Industrial Fired Boilers for General Refinery and Petrochemical Service

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a) Shall: As used in a standard, "shall" denotes a minimum requirement in order to conform to the specification.

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

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

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

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

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Introduction

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

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

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

Industrial Fired Boilers for General Refinery and Petrochemical Service

1 Scope

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

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

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

1.4 This RP does not cover forced circulation boilers.

2 Normative References

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

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

API Specification 6FA, *Specification for Fire Test for Valves*

API Recommended Practice 534, *Heat Recovery Steam Generators*

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

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

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

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

API Recommended Practice 551, *Process Measurement Instrumentation*

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

API Recommended Practice 555, *Process Analyzers*

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

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

API Recommended Practice 574, *Inspection Practices for Piping System Components*

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

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

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

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

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

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

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

AMCA Publication 99 [3], *Standards Handbook*

AMCA Publication 201, *Fans and Systems*, 2002

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

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

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

ASME B31.1 [6], *Power Piping*

ASME B31.3, *Process Piping*

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

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

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

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

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

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

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

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

ASTM D396, *Standard Specification for Fuel Oils*

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

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1 International Organization for Standardization, 1, ch. de la Voie-Creuse, Case postale 56, CH-1211 Geneva 20, Switzerland, www.iso.org.
2 American Boiler Manufacturers Association, 8221 Old Courthouse Road, Suite 202, Vienna, Virginia, 22015, www.abma.com
3 Air Movement and Control Association International, 30 West University Drive, Arlington Heights, Illinois 60004, www.amca.org.
4 American National Standards Institute, 25 West 43rd Street, 4th Floor, New York, New York 10036, www.ansi.org.
5 American Society of Heating, Refrigeration, and Air-Conditioning Engineers, 1791 Tullie Circle, N.E. Atlanta, Georgia 30329, www.ashrae.org.
6 ASME International, 2 Park Avenue, New York, New York 10016-5990, www.asme.org.
7 ASTM International, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania 19428, www.astm.org.

ASTM D1066, *Standard Practice for Steam Sampling*

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

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

IEEE 841-2009 [8], *Petroleum and Chemical Industry—Premium-efficiency, Severe-duty, Totally Enclosed Fan-cooled (TEFC) Squirrel Cage Induction Motors—Up to and Including 370 kW (500 hp)*

ANSI/ISA [9] 84.00.01-2004 (IEC 61511-1 Mod), *Functional Safety: Safety Instrumented Systems for the Process Industry Sector*

NBBI NB23[10], *National Board Inspection Code*, 2007

NFPA 85 [11], *Boiler and Combustion Systems Hazards Code*

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

U.S. EPA Contract No. 68-D-98-026 Work Assignment No. 0-08 [12], *Stationary Source Control Techniques Document for Fine Particulate Matter*

3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

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

3.1.1
adiabatic flame temperature
The highest attainable combustion temperature for the fuel and reactants at a specified inlet temperature and pressure if no energy is lost to the outside environment. Heat loss due to radiation, convection, or conduction is not included. Generally, the adiabatic flame temperature is determined for a stoichiometric fuel/air mixture.

3.1.2
air, excess
Additional air above the corrected theoretical air required to burn a fuel for stoichiometric combustion. Excess air is expressed as a percentage of the corrected theoretical air required for stoichiometric combustion.

3.1.3
air flow measurement instrument
A device for determining air flow quantity.

3.1.4
air flow permissive
A sensor that ascertains minimum air flow is present for purge and boiler operation.

3.1.5
air/fuel ratio
The ratio of the combustion air flow rate to the fuel flow rate.

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8 Institute of Electrical and Electronics Engineers, 445 Hoes Lane, Piscataway, New Jersey 08854, www.ieee.org.
9 The International Society of Automation, 67 T.W. Alexander Drive, Research Triangle Park, North Carolina, 22709, www.isa.org.
10 The National Board of Boiler and Pressure Vessel Inspectors, 1055 Crupper Avenue Columbus, Ohio 43229, www.nationalboard.org.
11 National Fire Protection Association, 1 Batterymarch Park, Quincy, Massachusetts 02169-7471, www.nfpa.org.
12 U.S. Environmental Protection Agency, Ariel Rios Building, 1200 Pennsylvania Avenue, NW, Washington, DC 20460, www.epa.gov.

3.1.6
air preheater
APH
A heat transfer apparatus through which combustion air is passed and heated by a medium of higher temperature such as combustion products, steam, or other fluid.

3.1.7
applicable code
The code, code section, or other recognized and generally accepted engineering standard or practice to which the system/equipment was built or that is deemed most appropriate for the situation.

3.1.8
asphaltic cutback
A viscous substance made of asphalt cement and petroleum solvent.

3.1.9
atomization
The breaking of a liquid into tiny droplets to improve fuel-air mixing and improve combustion. Steam, air, and fuel gas can be used as atomizing media. Steam is the most common in the refining industry. Atomization may also be accomplished by mechanical means.

3.1.10
atomizer
A device used to reduce a liquid fuel oil to a fine mist, using steam, air, or mechanical means.

3.1.11
attemperator
An apparatus for reducing and controlling the temperature of superheated steam.

3.1.12
authorized inspector
AI
A person designated by, or acceptable to, a jurisdiction that meets the requirements of the jurisdiction, the National Board Rules for In-service and New Construction Commissioned Inspectors.

3.1.13
availability
Calculated probability, expressed as a percentage, that a protective function will take the correct action to safe state on process demand.

3.1.14
basic process control system
BPCS
A system that responds to input signals from the process, its associated equipment, other programmable systems, and/or an operator and generates output signals causing the process and its associated equipment to operate in the desired manner.

3.1.15
blowdown
A sudden or routine release of the boiler contents to control solids in the boiler water. Blowdown protects boiler surfaces from severe scaling or corrosion problems that can result otherwise. Boiler blowdowns can be continuous or intermittent.

3.1.16
boiler
A closed vessel in which water is heated, steam is generated, steam is superheated, or any combination thereof by the application of heat from combusting fuels in a self-contained or attached furnace.

3.1.17
boiler bank
The collection of tubes that connect the upper and lower (mud) steam drums or headers. Steam rises from the lower drum or headers to the upper drum and water flows from the upper drum to the lower drum or headers and out to the boiler's waterwalls.

3.1.18
boiler control system
The group of control systems that regulates the boiler process, including the CCS, but not the BMS. The boiler control system responds to input signals from the equipment under control and/or from an operator and generates output signals, causing the equipment under control to operate in the desired manner.

3.1.19
boiler enclosure
The physical boundary for all boiler pressure parts and for the combustion process.

3.1.20
boiler feedwater
BFW
Water supplied to the boiler at high pressure. Typically treated to remove oxygen, precipitates, or other contaminants that can impair a boiler's performance.

3.1.21
boiler feedwater control
The control that regulates water flow and maintains steam/water interface within an acceptable range in the steam drum for all operating conditions.

3.1.22
boiler water
Water inside the steam drum. Boiler water solids concentration is much higher than in the boiler feedwater.

3.1.23
bundle
Groups of tubes arranged in a way that can be extracted for maintenance and cleaning.

3.1.24
burner
A device that introduces fuel and air into a boiler at the desired velocities, turbulence, and concentration to establish and maintain proper ignition and combustion.

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

3.1.25
burner management system
BMS
The system (logic, sensors, actuating devices, final elements, PLC) devoted to the starting and stopping of fuel burning equipment (fuel train and fans) in the proper sequence for safe operation, and tripping equipment when necessary to prevent damage.

3.1.26
bypass
A passage conveying a substance from the upstream side to the downstream side of a control device or equipment item so as to be independent of the action of the control.

3.1.27
capacity
The maximum main steam mass flow rate that the steam generator is capable of producing on a continuous basis with specified steam conditions and cycle configuration (including specified blowdown and auxiliary steam). This is frequently referred to as maximum continuous rating (MCR).

3.1.28
capacity, peak
The maximum main steam mass flow rate that the steam generator is capable of producing with specified steam conditions and cycle configuration (including specified blowdown and auxiliary steam) for intermittent operation, i.e. for a specified period of time without affecting future operation of the unit.

3.1.29
cavitation
The formation and violent collapse of vapor bubbles in a liquid caused by movement of something such as a pump impeller. Cavitation is potentially damaging to exposed surfaces.

3.1.30
chelate
An organic compound used in boiler water treatments that bonds with free metals in solution. Chelates help prevent metals from depositing upon tube surfaces.

3.1.31
chemical upset
A condition outside of normal operating conditions caused by incorrect dosing of boiler chemicals or incorrect boiler water chemistry.

3.1.32
circulation ratio
Mass ratio of (steam + water)/steam.

3.1.33
combustion control system
CCS
The control system that regulates the furnace fuel and air inputs to maintain the air-fuel ratio within the limits that are required for continuous combustion and stable flame throughout the operating range of the boiler in accordance with demand.

3.1.34
computational fluid dynamics
CFD
Numerically modeling a system's physics using fluid dynamic equations for continuity, momentum, and energy.

3.1.35
conductivity
A measure of the ability of a material to conduct an electric current. In this document it generally refers to water conductivity, which is a surrogate for total dissolved solids and is reported as micro S/cm or micro mho/cm. These two units are equivalent. Micro S/cm will be used throughout the document.

3.1.36
continuous blowdown
Water continuously taken from the steam drum at a controlled rate to reduce the level of dissolved solids to specified requirements. Utilizes a calibrated valve and a blowdown tap near the boiler water surface to reduce the level of dissolved solids.

3.1.37
convection section
Portion of the boiler in which the primary heat transfer mechanism is by convection.

3.1.38
corrosion allowance
The additional metal thickness added to allow for metal loss during the design life of the component. It is the corrosion rate multiplied by the component design life, expressed in inches or millimeters.

3.1.39
corrosion rate
The annual reduction in material thickness due to chemical attack from process fluid or flue gas, or both.

3.1.40
critical heat flux
CHF
A set of operating conditions that occurs when relatively high heat transfer rates from the tube wall to the steam/water mixture flowing inside the tube, associated with nucleate or forced convective boiling, change to lower rates associated with transition or film boiling. This causes DNB.

3.1.41
damper
A device for regulating volumetric flow of gas or air by introducing variable resistance to air entering a fan.

3.1.42
dead band
The range through which the control input signal may be varied, upon reversal of direction, without initiating an observable change in valve position.

3.1.43
dead time
Td
The interval of time between initiation of an input change or stimulus and the start of the resulting observable response.

3.1.44
deaerator
An open-type heater in which small droplets and thin films of water are brought into intimate contact with steam, thereby raising the water temperature to its boiling point at the deaerator pressure. As the water approaches the boiling point, the solubility of the “gas” in the liquid decreases significantly. The steam also serves to strip oxygen and carbon dioxide from the makeup water for removal via the vent(s) from the stripping section.

3.1.45
departure from nucleate boiling
DNB
Occurs when the applied heat flux to a tube becomes greater than or equals the CHF value. The liquid film that was present along the tube wall at lower heat fluxes disappears, the heat transfer coefficient decreases, and the tube wall temperature increases.

3.1.46
desiccant
A substance that absorbs water used for the removal of moisture.

3.1.47
desuperheater
See **attemperator** definition.

3.1.48
directional blocking
An interlock that, upon detection of a significant error in furnace pressure or HRSG process variables, acts to inhibit the movement of all appropriate final control elements in the direction that would increase the error.

3.1.49
downcomer
Boiler tubes or pipes that take boiler water away from the steam drum and to the heat absorbing surfaces where steam is generated.

3.1.50
draft
Negative pressure (vacuum) of flue gas or air at any point in the boiler.

3.1.51
duct
A conduit for air or flue gas flow.

3.1.52
economizer
A section of the boiler where incoming feedwater temperature is raised to less than saturation temperature by recovery of the heat from flue gases leaving the boiler.

3.1.53
effective projected radiant surface
The total flat projected area of the non-refractory lined waterwalls, the floor, roof, both sides of the radiant superheater, furnace exit plane, and waterwall platens.

3.1.54
erosion
A reduction in material thickness due to mechanical attack from a fluid, expressed in inches or millimeters.

3.1.55
evaporator
The area of the boiler where water boils to form steam. Typically, a mixture of water and steam exits at the outlet of this area. Also referred to as the steam generator section.

3.1.56
extended surface
Refers to the heat transfer surface in the form of fins or studs attached to the heat absorbing surface.

3.1.57
fan actual flow rate
The volume flow rate determined at the conditions of static pressure, temperature, compressibility, and gas composition, including moisture, at the fan inlet flange.

3.1.58
fan inlet velocity pressure
The difference between fan static pressure and static pressure rise.

3.1.59
fan maximum allowable speed
The highest speed at which the manufacturer's design permits continuous operation.

3.1.60
fan rated point (fan capacity)
The capacity and pressure rise required by fan design to meet all specified operating points.

3.1.61
fan rated point (fan speed)
The highest speed necessary to meet any specified operating condition.

3.1.62
fan static pressure
Difference between the fan total pressure and the fan velocity pressure.

3.1.63
fan static pressure rise
Static pressure at the fan outlet minus the static pressure at the fan inlet.

3.1.64
fan total pressure
Difference between the total pressure at the fan outlet and the total pressure at the fan inlet.

3.1.65
fan trip speed
Speed at which the independent emergency overspeed device operates to shut down a prime mover.

3.1.66
fan velocity pressure
Pressure corresponding to the average velocity at the specified fan outlet area.

3.1.67
filter strainer
strainer/filter
A device that removes and collects particles of iron, dirt, etc. that could otherwise cause fouling and/or failures in the system.

3.1.68
firebox
An enclosed space provided for the combustion of fuel. Also known as the furnace or combustion chamber.

3.1.69
flame detector
The flame-sensing element. Its output signal is the input for the flame safeguard amplifier.

3.1.70
flame envelope
The term used to define the flame contour (width and length); usually corresponds to the boundary (not necessarily visible) at which 99.5 % of the fuel is fully converted to CO_2 and H_2O.

3.1.71
flame failure
The loss of flame detection by any cause other than a deliberate, intended action.

3.1.72
flame safeguard
The flame detector that detects a flame and in the event of failure to ignite, igniter failure, or main flame failure, removes the flame proving signal to the BMS to initiate a safety shutdown. The flame safeguard consists of a flame detector, an amplifier, and a safety certified output (typically discrete relay output) for signal transmission.

3.1.73
flue gas
The gaseous product of combustion including the excess air.

3.1.74
fluid catalytic cracking
FCC
A process whereby heavy distillates or residues are converted into higher value products.

3.1.75
flushing
A cleaning procedure whereby the interior surfaces are rinsed to remove deposits.

3.1.76
forced draft fan
FD fan
A device used to supply ambient combustion air to the combustion chamber burners.

3.1.77
fouling resistance
Heat transfer resistance used to calculate the overall heat transfer coefficient.

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

3.1.78
fuel efficiency
Total heat absorbed by the steam and water divided by the total input of heat derived from the chemical energy of the fuel combusted (HHV basis excludes sensible heat of the fuels, but includes sensible heat from air preheat).

3.1.79
fuel ignition safety time
The period during which the main fuel SSV(s) is (are) permitted to be open before the igniter flame is extinguished and before the flame safeguard is required to supervise the main flame alone.

3.1.80
furnace
The portion of a boiler where combustion takes place.

3.1.81
furnace (firebox) area heat release rate [Btu/(h-ft^2) or W/m^2]
The total boiler heat input on HHV basis divided by the furnace effective (projected) radiant cooling surface area.

3.1.82
furnace (firebox) heat flux [Btu/(h-ft^2) or W/m^2]
The net heat absorbed by the furnace portion divided by the effective (projected) furnace area.

3.1.83
heat flux density
Heat absorbed divided by the exposed heating surface of a specific coil section.

3.1.84
heat recovery steam generator
HRSG
A system in which steam is generated and may be superheated or water heated by the transfer of heat from gaseous products of combustion or other hot process fluids.

3.1.85
higher heating value gross heating value
HHV gross heating value
Total heat obtained from the combustion of a specified fuel when all the products of combustion are at the original pre-combustion temperature. H_2O is a liquid byproduct.

3.1.86
igniter
A permanently installed device that provides proven ignition energy to light-off the main burner.

3.1.87
ignition period (igniter and main burner)
Defined time intervals that start with the opening of the fuel SSVs during light-off. Failure to detect flame at the end of these time intervals results in fuel supply shutoff.

3.1.88
ignition safety time
The period of time that starts with the opening of the fuel supply during the start-up process and ends, in the absence of a flame, with the shutting off of the fuel supply.

3.1.89
induced draft fan
ID fan
A device used to remove the products of combustion from the boiler.

3.1.90
infrared thermography
IR
Detection of radiation in the infrared range of the electromagnetic spectrum using a thermal imaging camera and the production of images of that radiation, called "thermograms."

3.1.91
intermittent (manual) blowdown
Periodically removing boiler water through taps at the bottom of the boiler. These openings allow for the removal of solids/sludges that settle at the bottom of the boiler. Intermittent blowdown is also used to keep water level control devices and cutoffs clear of any solids that would interfere with their operation.

3.1.92
intermittent igniters
Igniters that support burner operation in certain operating modes.

3.1.93
interrupted igniters
Igniters used for initial burner light-off only.

3.1.94
jurisdiction
A legally constituted government administration that may adopt rules relating to equipment.

3.1.95
lagging
External sheathing (typically metal) that protects insulation from atmosphere and elements.

3.1.96
layup
A period of time during which a boiler is inoperative in order to allow for repairs or preventive maintenance.

3.1.97
leak tightness device
A system to prove the effective closure of the main fuel SSVs and that is capable of

a) detecting small fuel leakage rates, e.g. a pressure proving system, and

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

3.1.98
logic system
The decision-making and translation elements of the BMS. A logic system provides outputs in a particular sequence in response to external inputs and internal logic. Logic systems are comprised of the following:

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

b) operating system and logic software.

3.1.99
louver damper
A damper consisting of several blades, each pivoted about its center and linked together for simultaneous operation.

3.1.100
lower flammable limit
The lowest ignitable concentration of fuel gas or vapor in air. Below this concentration, a fuel gas/air mixture will not ignite. The lower flammability limit decreases with increasing temperature.

3.1.101
lower heating value net heating value
LHV net heating value
Heat obtained from combustion with water vapor as a combustion product, i.e. HHV less 2442.5 kJ/kg (1050.1 Btu/lb).

3.1.102
main flame establishment period
A period during which the main fuel SSV(s) is/are permitted to be open before the igniter flame is extinguished and before the flame safeguard is required to supervise the main flame alone.

3.1.103
manifold
A chamber for the collection and distribution of fluid to or from multiple parallel flow paths.

3.1.104
manufacturer
The entity that constructs the boiler, boiler components, and/or associated equipment in accordance with specifications provided by purchaser and requirements of applicable standards. While the manufacturer may subcontract all or part of the construction, the manufacturer remains fully responsible for the work product. The manufacturer may or may not be the vendor.

3.1.105
master fuel trip
MFT
An event resulting in the rapid shutoff of all fuel, including igniters, and de-energizing spark ignition.

3.1.106
material safety data sheet
MSDS
A data sheet that catalogs chemical, chemical compound, and chemical mixture information, focusing on the hazards when the material is used in work settings.

3.1.107
maximum continuous rating
MCR
See **capacity** definition.

3.1.108
mud drum
The lower drum of a two-drum boiler where boiler water sediments settle out and collect.

3.1.109
nondestructive examination
Evaluation of the properties of a material, component, or system without causing damage.

3.1.110
operator supervision
A circumstance by which an operator has continuous control and surveillance of the plant and is located in a position where he/she can shut the plant down in the event of an emergency.

3.1.111
original equipment manufacturer
OEM
The company that originally manufactured the equipment.

3.1.112
overshoot
The amount by which the step response initially exceeds the final steady state value (% of step change).

3.1.113
owner
Having legal title to the boiler, boiler components, and/or associated equipment. The owner may or may not be the purchaser and/or user.

3.1.114
pegging steam
Steam fed to the deaerator to achieve saturation conditions inside the deaerator and to create a scrubbing action between the steam and the feedwater, by which dissolved corrosive gases (mainly O_2, CO_2, and NH_3) that become corrosive at elevated temperatures can be eliminated. The removal of these gases is necessary to protect the piping and associated equipment. The gases removed are vented from the deaerator to atmosphere.

3.1.115
penetrant testing
Penetrant testing, or liquid penetrant inspection, is an inspection method used to locate surface-breaking defects, e.g. hairline cracks, surface porosity, and fatigue cracks, by applying a dye penetrant.

3.1.116
personal protective equipment
A protective garment or equipment designed to protect the wearer's head (helmet), eyes (glasses, goggles), hands (gloves), ears (plugs, muffs), and body from injury.

3.1.117
pressure design code
The recognized pressure vessel standard specified or agreed by the purchaser, e.g. ASME *Boiler and Pressure Vessel Code*.

3.1.118
programmable logic controller
PLC
A computer that uses multiple inputs and output arrangements to control a boiler. PLCs are programmed using application software.

3.1.119
prove
To establish by measurement or test the existence of a specified condition such as flame, flow, level, pressure, position, etc.

3.1.120
purchaser
The one who procures the boiler, boiler components, and/or associated equipment. The purchaser may, or may not, be the owner and/or user.

3.1.121
purge
A flow of air at a rate that will effectively remove and displace any gaseous combustibles and replace them with the purging medium.

3.1.122
quarl
The refractory blocks surrounding the burner components. The shape of the burner tile forms the air flow path between the throat and the exit of the burner and helps stabilize the flame.

3.1.123
radiant section
The portion of the boiler in which the primary heat transfer mechanism is by radiation.

3.1.124
register (burner air)
A set of dampers for a burner, or an air supply system to a particular burner, used to distribute the combustion air admitted to the combustion chamber. The register frequently controls the direction and velocity of the airstream for efficient mixing with the incoming fuel.

3.1.125
reliability
Measure of the ability of equipment/systems to operate without malfunction or failure between planned maintenance interventions.

3.1.126
residual catalytic cracking
RCC
The residual fluid catalytic cracking process has its similarities to the fluid catalytic cracking process; however, in the RCCUs, heavy feedstocks are employed. As in FCCUs, hot flue gas developed from catalyst regeneration is used to generate steam in a waste heat boiler.

3.1.127
Ringelmann number
A visually comparative scale used to define levels of opacity, where clear is 0, black is 5, and 1 through 4 are increasing levels of gray.

3.1.128
riser
Boiler tubes or pipes where the two-phase fluid flow is toward the steam drum for separation.

3.1.129
safety instrumented function
SIF
A protective function that takes corrective action to safe state when unacceptable process conditions are detected. It can be either a safety instrumented protection function or a safety instrumented control function.

3.1.130
safety instrumented system
SIS
An instrumented system that implements one or more SIFs to maintain the boiler in a safe state when unacceptable or dangerous process conditions are detected. An SIS is composed of any combination of sensor(s), logic solver(s), and final elements.

3.1.131
safety integrity level
SIL
A discrete level (one out of four) for specifying the safety integrity requirements of the safety instrumented functions to be allocated to the safety instrumented systems. Safety integrity increases from level 1 to level 4.

3.1.132
safety shutdown
The process that is initiated immediately in response to a BMS signal and that causes the burner(s) to shut down.

3.1.133
Sauter mean diameter
SMD
The diameter of a droplet whose specific surface is the same as that for the total number of droplets in the spray.

3.1.134
self-checking flame detector
A flame detector that automatically, and at regular intervals, tests the entire sensing and signal processing system of the flame detector.

3.1.135
sootblower
A mechanical device for discharging steam or air to clean heat-absorbing surfaces.

3.1.136
stack
A vertical conduit used to discharge flue gas to the atmosphere.

3.1.137
steam drum
A pressure vessel whose primary purpose is to separate liquid and vapor phases. Steam drums also provide an operating water storage capacity.

3.1.138
steam purity
The measurement of solid carryover in the steam.

3.1.139
steam quality
A measure of the amount of moisture in the steam step resolution.

3.1.140
steam temperature control range
The capacity range over which main steam temperature and/or reheat steam temperature may be maintained at the rated conditions.

3.1.141
step resolution
The minimum step change in input signal to which the control valve system will respond while moving in the same direction.

3.1.142
step response time (T63)
The time after an input signal step change until the output has reached 63 % of the final steady state value.

3.1.143
step response time (T86)
The time after an input signal step change until the output has reached 86.5 % of the final steady state value.

3.1.144
stoichiometric air
The chemically correct amount of air required for complete combustion with no unused fuel or air in the products.

3.1.145
stoichiometric fuel rate
That fuel rate at which, if reacted completely with the combustion air flow, the fuel would just consume all the oxygen in the air.

3.1.146
stoichiometric ratio
The ratio of fuel and air required for complete combustion such that the combustion products contain no oxygen.

3.1.147
superheater
The portion of the boiler in which saturated steam is heated to higher temperatures.

3.1.148
sweetwater condenser
Condenses saturated steam from the steam drum in a shell and tube exchanger utilizing feedwater as the cooling medium on the tube side. Condensed saturated steam is used to attemporate superheated steam.

3.1.149
thermal efficiency
Total heat absorbed divided by the total input of heat derived from the combustion of fuel (hL) plus sensible credits. Credits include sensible heat from air, fuel, atomizing steam, and auxiliary power to drives.

3.1.150
unburned combustible
The combustible portion of the fuel that is not completely oxidized.

3.1.151
upper flammable limit
The highest ignitable concentration of fuel gas or vapor in air. Above this concentration, fuel gas/air mixture will not ignite. The upper flammability limit increases with increasing pressure.

3.1.152
user
The organization or individual using or operating the boiler and associated equipment. The user may or may not be purchaser and/or owner.

3.1.153
valve-proving system
The system that proves the leak tightness of the burner and igniter SSVs and prevents main burner or igniter light-off if leak tightness requirements are not satisfied.

3.1.154
vendor
The entity that supplies the boiler, boiler components, and/or associated equipment.

3.1.155
volatile corrosion inhibitors
VCIs
Organic compounds that prevent metal surfaces from corroding by creating an invisible barrier that emits rust blockers at a molecular level.

3.1.156
volumetric heat release
Heat released divided by the net volume of the firebox.

3.1.157
water tube boiler
A multiple tube circuit heat exchanger within a gas-containing casing in which steam is generated inside the tubes by heat transferred from a hot gas flowing over the tubes.

3.1.158
waterwalls
Tubes forming the walls of the boiler. Water flows to these tubes from the steam drum through the downcomer piping. As the water in these tubes absorbs heat, water changes phase to a water/steam mixture that rises through these tubes due to its lower density, compared to water in the downcomer tubes.

3.2 Acronyms and Abbreviations

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

LEL	lower explosion limit
LHV	lower heating value
LLCO	low level cutoff
LWA	low water alarm
LWCO	low water cutout
LWL	low water level
MAWP	maximum allowable working pressure
MCR	maximum continuous rating
MFGCV	main fuel gas control valve
MFT	master fuel trip
MSDS	material safety data sheet
NH_3	ammonia
NOx	oxides of nitrogen
OD	outside diameter
NRV	non-return valve
NWL	normal water level
OEM	original equipment manufacturer
PIF	protective instrumented function
PLC	programmable logic controller
POF	position on failure
PMI	positive materials identification
PST	partial stroke testing
RAGAGEP	recognized and generally accepted good engineering practice
RCC	residual catalytic cracking
RCCU	residual catalytic cracking unit
RTD	resistance temperature detector
SCR	selective catalytic reduction
SG	specific gravity
SIF	safety instrumented function
SIL	safety integrity level
SIS	safety instrumented system
SMD	Sauter mean diameter
SNCR	selective non-catalytic reduction
SOx	oxides of sulfur
SSU	Saybolt seconds universal
SSV	safety shutoff valve
TDS	total dissolved solids
TFI	trial-for-ignition
TOC	total organic carbon
UBHC	unburned hydrocarbon

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

4 Boilers—Equipment Overview

4.1 General Considerations

4.1.1 General

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

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

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

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

4.1.2 Steam Pressure

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

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

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

4.1.3 Superheated and Saturated Steam

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

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

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

4.1.4 Steam/Water Circulation

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

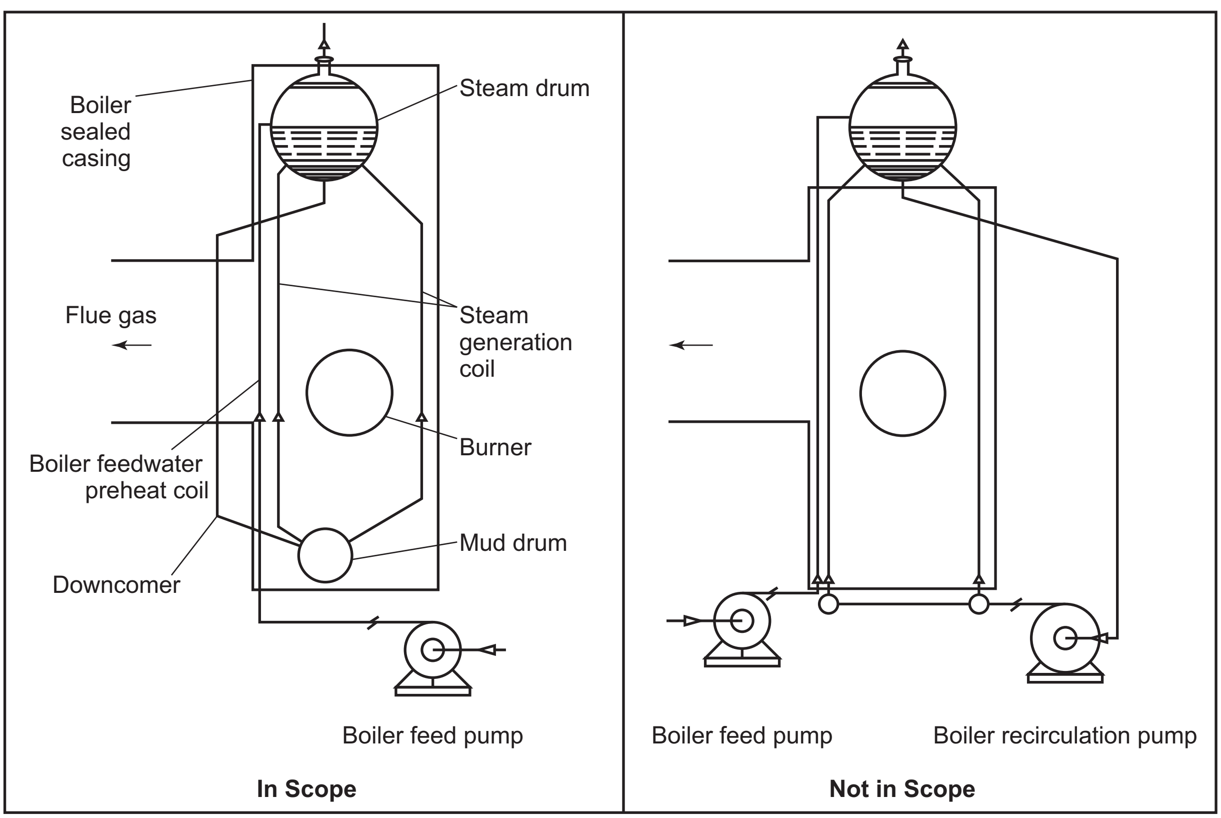


Figure 1—Boiler Steam and Water Circulation

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

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

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

4.1.5 Steam Production and Capacity

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

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

4.1.6 Fuel Types

Refinery boilers burn several different types of liquid and gaseous fuels, and frequently these boilers will simultaneously burn more than one fuel. Fuels that these boilers commonly burn are natural gas, oil, and refinery gas (similar to natural gas). At many refineries a fluid catalytic cracking unit (FCCU) produces a gas called "regeneration gas," which contains carbon monoxide (CO). The CO shall be oxidized or combusted to CO_2 so it is either sent directly to a boiler from the FCCU's regenerator or sent to a thermal oxidizer and then sent to a waste heat boiler. The boiler shall be designed to burn the maximum and minimum amount of regeneration gas from the FCCU. Since the regeneration gas has a low higher heating value (HHV), a supplementary fuel, such as refinery blended gas, shall be burned as well.

Each refinery boiler is designed specifically for the fuel(s) to be burned. Some of the common design characteristics that change based on the fuel are furnace heat release rate, flue gas velocities through tube banks, and tube spacings. Different fuel types have different adiabatic flame temperatures and air/fuel requirements that may change the radiant/convective heat absorption ratio; each boiler's surface requirements must be tailored to the fuels proposed to be fired. Each type of fuel burned also has different combustion products. The boiler operator shall consider the emission of these combustion products to meet federal, state, local emission, and final user's requirements.

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

4.1.7 Seasonal Water and Steam Balances

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

4.1.8 Boiler Sparing Philosophy

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

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

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

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

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

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

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

4.2 Operations

4.2.1 Strategies Overview

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

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

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

4.2.2 Steam and Water Operating Guide

4.2.2.1 General

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

4.2.2.2 Boiler Water Level

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

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

4.2.2.3 Boiler Water Blowdown

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

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

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

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

4.2.2.4 Intermittent Blowdown

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

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

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

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

4.2.2.5 Continuous Blowdown

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

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

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

4.2.2.6 Saturated Steam Sampling

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

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

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

4.2.2.7 Boiler Feedwater Control

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

4.2.2.8 Attemperation and Desuperheating

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

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

a) Spraying desuperheaters: These may be installed at the outlet of the superheater coil or in an interstage configuration. Spray water will, in many cases, be BFW, provided the steam purity is not adversely affected; in some cases it can be condensate or demineralized water.

b) Steam desuperheating: Some designs can use saturated steam as the attemperating media, but these are rather uncommon.

c) Fireside control methods: This can involve changes to burners, masking of furnace surfaces, etc.

d) Steam condensers, also known as sweetwater condensers: In these cases a portion of the steam is drawn from the boiler prior to entering the superheater and then the steam is condensed by removing the latent heat (typically from BFW). The advantage of this system is that the re-injected condensate does not introduce foreign impurities into the superheater stream.

e) Other methods suggested by the boiler manufacturer.

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

4.2.2.9 Superheater Start-up Vent

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

4.2.2.10 Superheater Drains

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

4.2.2.11 Economizer

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

4.2.3 Air and Flue Gas

4.2.3.1 General

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

4.2.3.2 Air Moving Equipment

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

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

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

4.2.3.3 Dampers

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

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

4.2.3.4 Stack Dampers

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

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

4.2.3.5 Air and Flue Gas Ductwork

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

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

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

4.2.3.6 Flue Gas Recirculation Ductwork

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

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

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

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

4.2.4 Fuel and Combustion

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

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

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

4.2.5 Sootblowers

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

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

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

The controls system shall be of the open architecture type.

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

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

a) the header shall be warm,

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

4.3 Boiler Configurations

4.3.1 General

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

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

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

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

4.3.2 Water Tube Package "D" Boiler

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

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

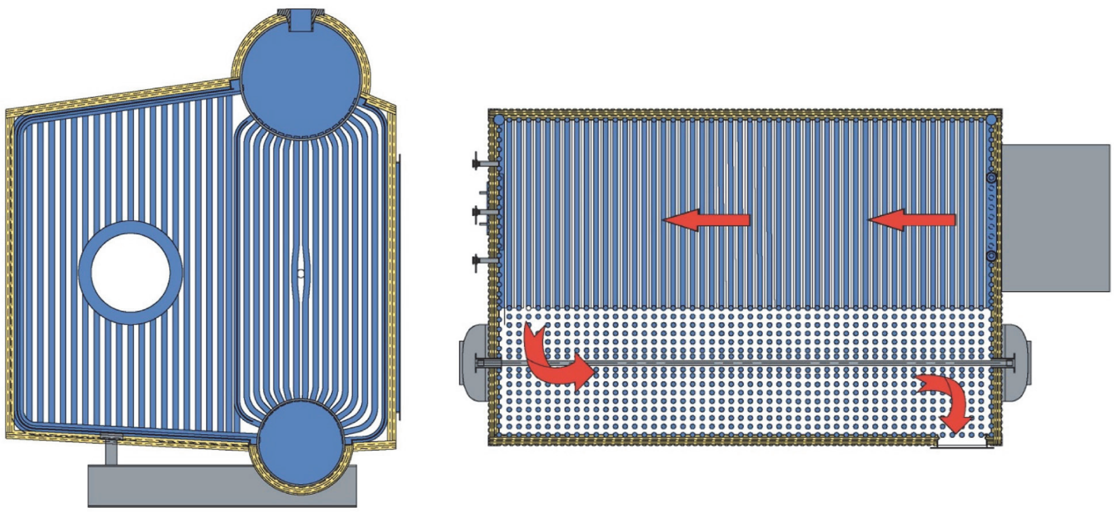


Figure 2—Water Tube Package "D" Boiler

4.3.3 Water Tube Package "O" Boiler

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

4.3.4 Water Tube Package "A" Boiler

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

4.3.5 Modular Boiler

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

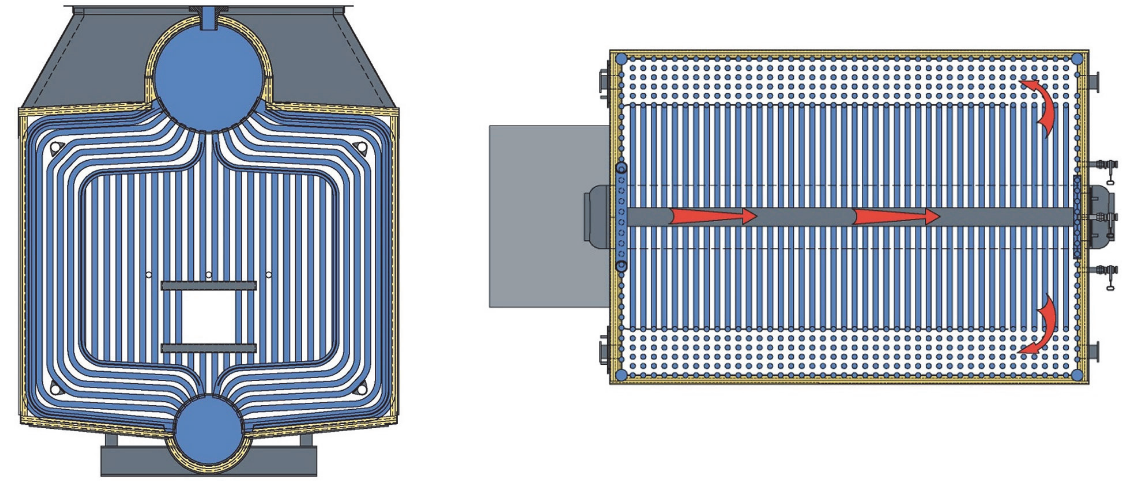


Figure 3—Water Tube Package "O" Boiler

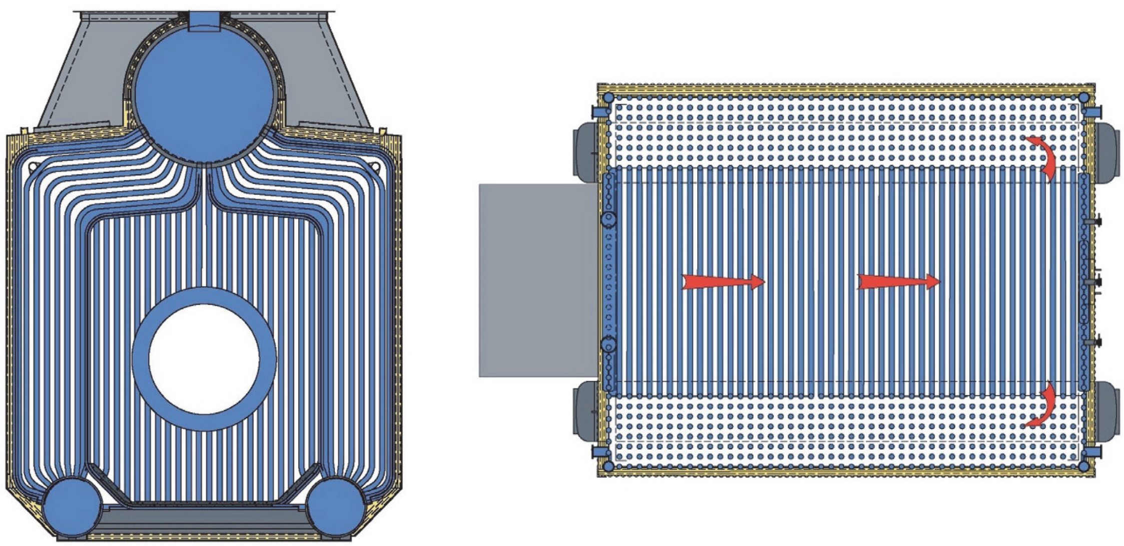


Figure 4—Water Tube Package "A" Boiler

4.3.6 Single Steam Drum Boiler

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

4.3.7 Field Erected Boiler

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

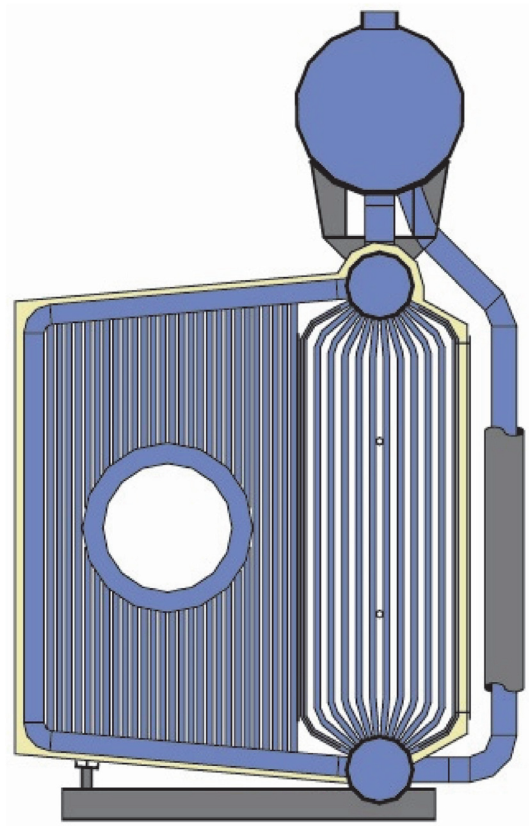


Figure 5—Modular Boiler

4.3.8 CO Boiler

4.3.8.1 General

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

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

There are three types of FCCUs:

a) FCC with a regenerator with full combustion,

b) FCC with a regenerator with partial combustion,

c) FCC with two regenerators—one with partial combustion and one with full combustion.

Steam generator types are as follows.

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

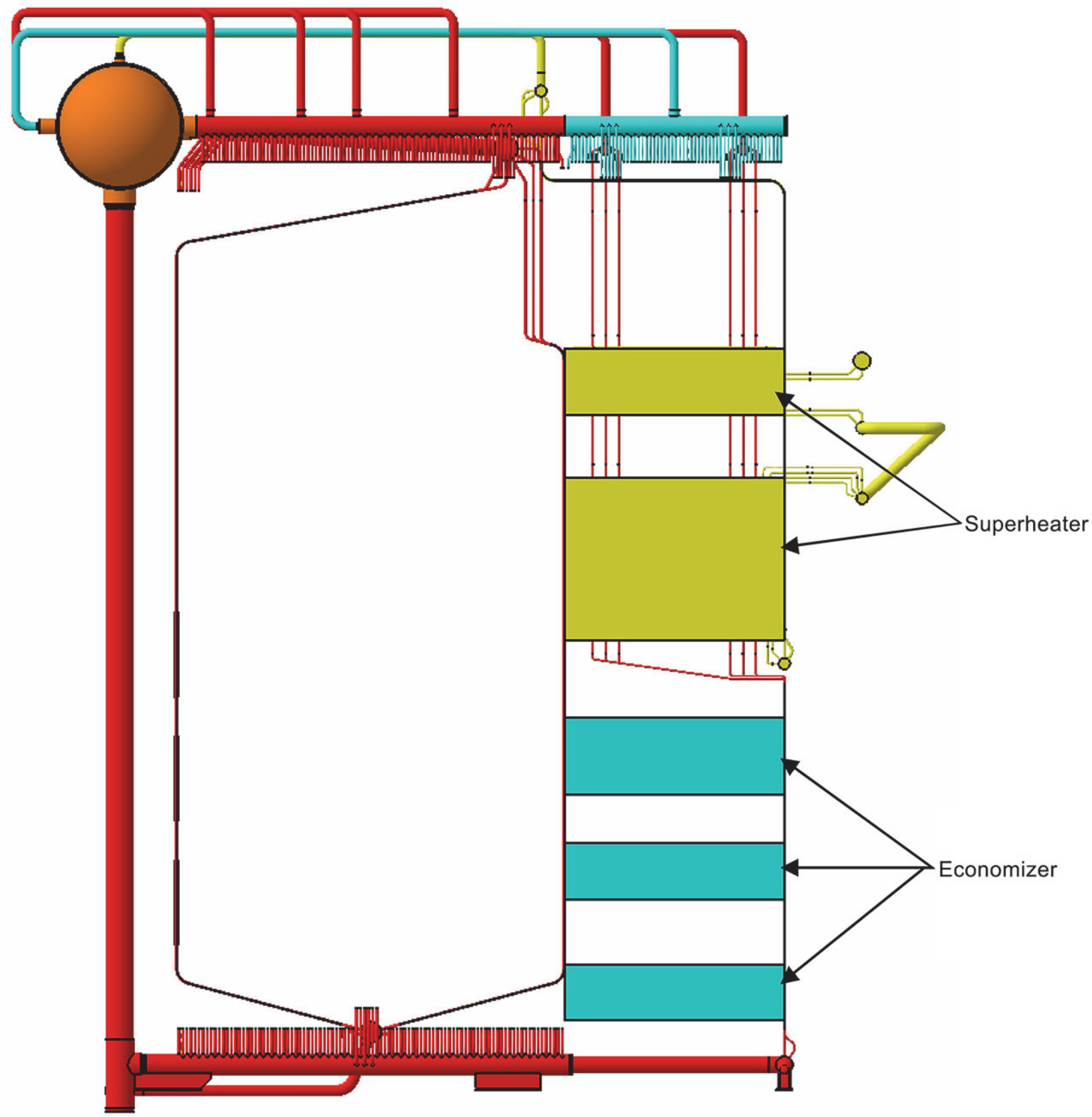


Figure 6—Single Steam Drum Boiler

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

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

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

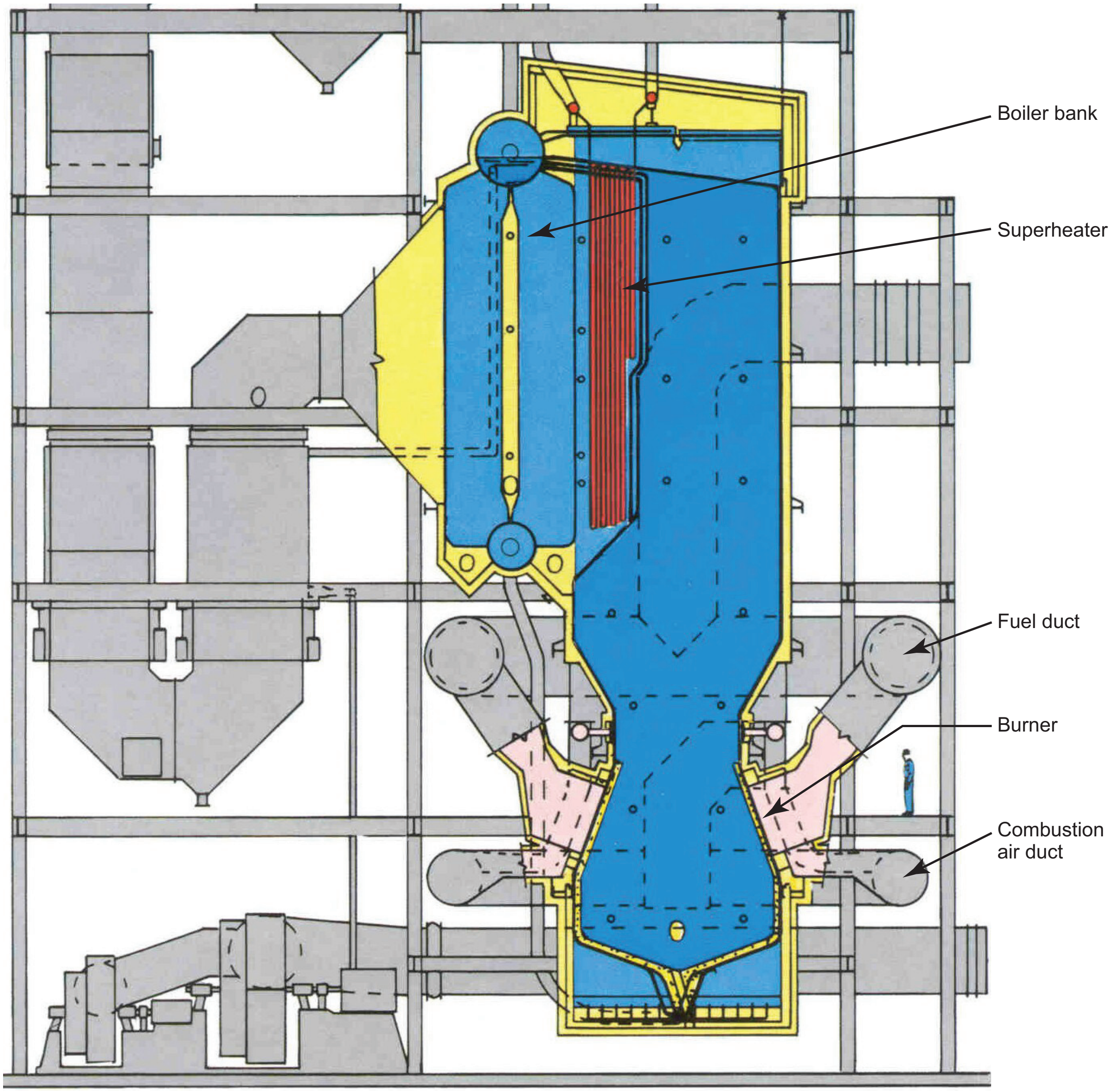


Figure 7—Field Erected Boiler

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

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

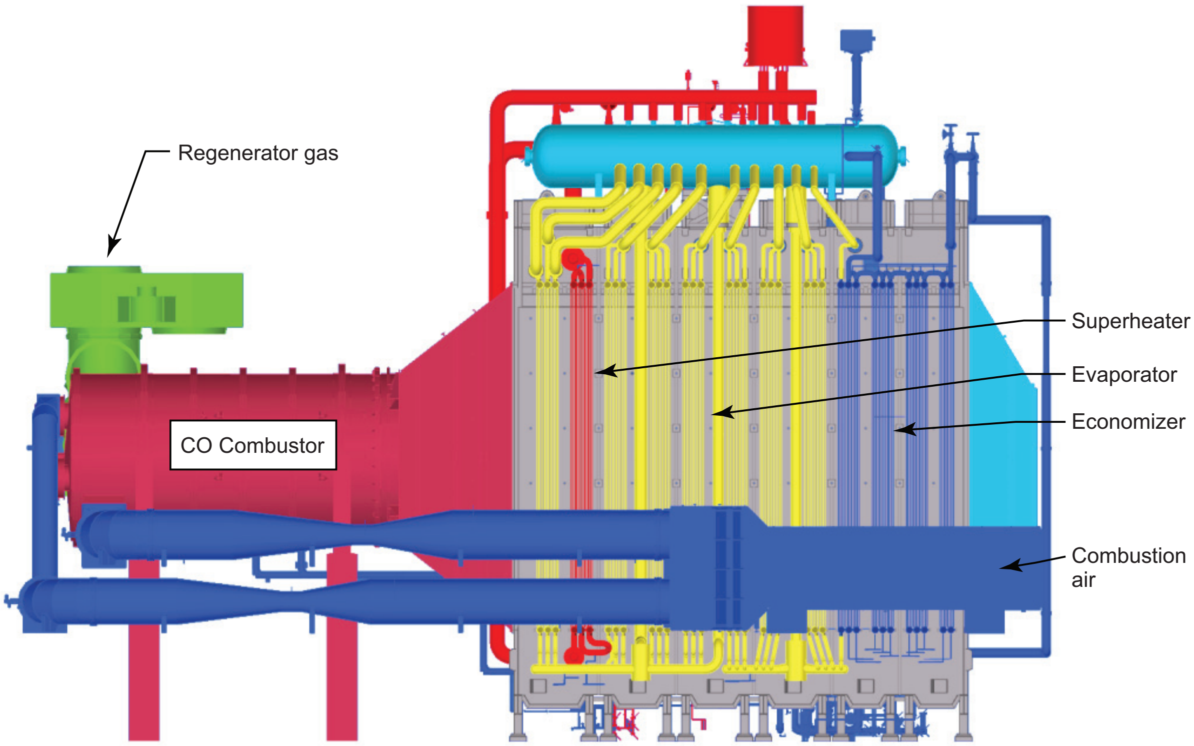


Figure 8—Carbon Monoxide Combustor and Heat Recovery Steam Generator

1) Two CO boilers, one as an HRSG and one a CO boiler with supplementary fuel to combust and render harmless the CO (two types possible; see above).

2) Only one CO boiler with supplementary firing (two types possible; see above). The flue gas from the second regenerator is mixed in the flue gas after CO combustion, upstream of the convection sections.

The second design option is preferable.

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

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

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

4.3.8.2 Adiabatic CO Boiler Design

4.3.8.2.1 General

The adiabatic, or thermal oxidizer, type of CO boiler achieves very high rates of CO destruction by combusting the CO-rich residual catalytic cracking (RCCU) gas (flue gas from a regenerator) in an internally insulated chamber. As there is minimal heat loss through the internal insulation, the uniformly high temperature of the combustion chamber promotes efficient oxidation of CO to CO_2.

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

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

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

4.3.8.2.2 Sulfur Dew Point Corrosion

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

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

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

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

4.3.8.3 Thermal Oxidizer

4.3.8.3.1 Theory for Adiabatic Combustion

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

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

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

4.3.8.3.2 Mixing

Air is typically introduced in multiple locations in the thermal oxidizer. Air is needed to oxidize the CO to CO_2, combustion air is required for the supplemental fuel, and quench air is added to control the temperature in the incinerator.

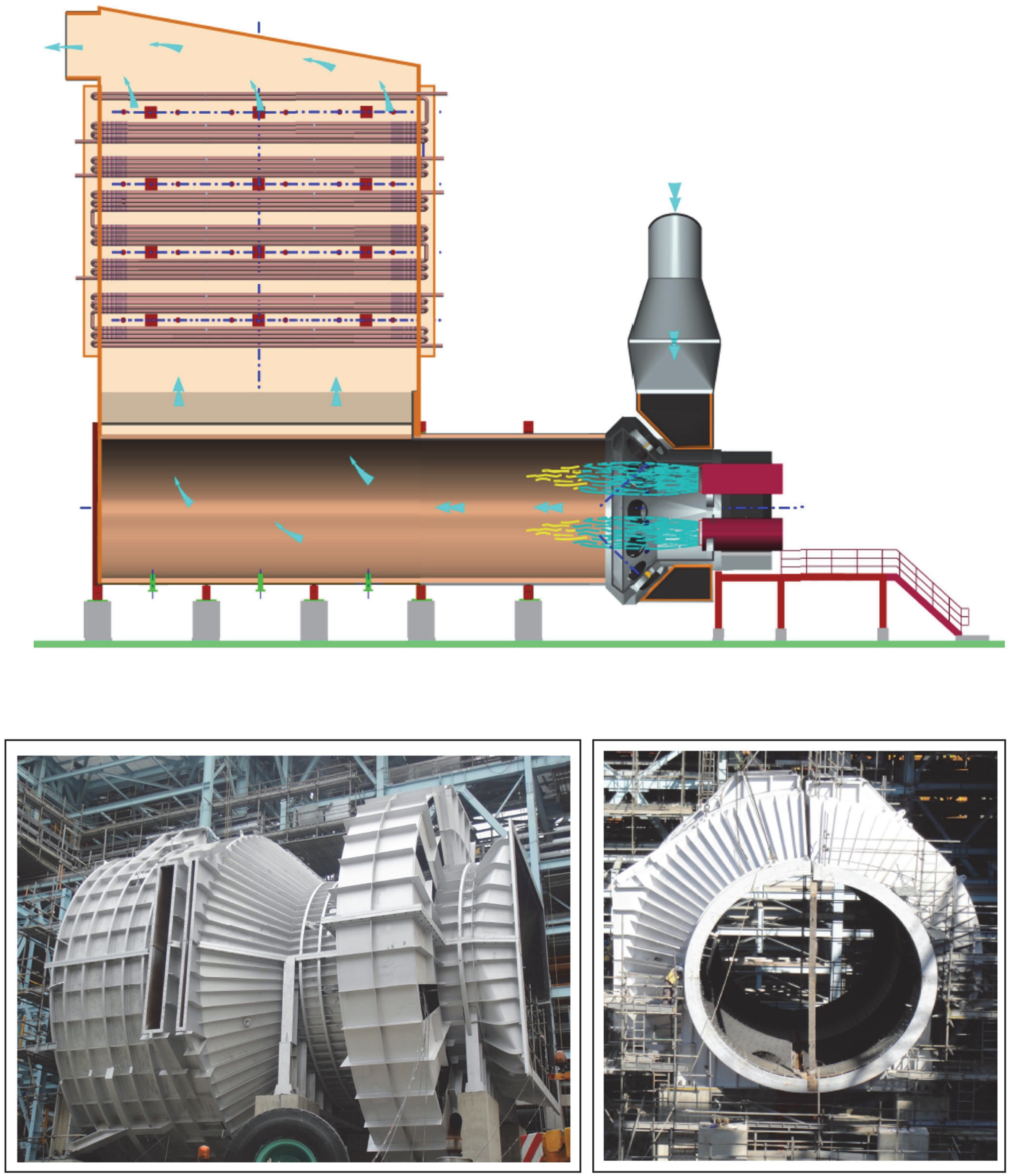


Figure 9—Thermal Oxidizer

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

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

4.3.8.3.3 Refractory

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

a) The design of the refractory lining of the RCCU waste gas inlet shall consider both the elevated temperatures and the erosive nature of the RCCU waste gas. Depending on the design of the RCCU waste gas inlet, a single layer refractory system or a multiple layer refractory system is utilized to protect the RCCU waste gas inlet portion of the thermal oxidizer. The hot face layer should consist of an abrasion resistant material.

b) In the main combustion zone, which includes the entire flame length, refractory also consists of a multiple layer system. The hot face layer here shall be suitable for direct exposure to the flame and be sufficiently strong to prevent erosion. The effect of radiation from the flame should also be considered.

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

4.3.8.4 Waste Heat Boiler

4.3.8.4.1 General

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

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

a) Clean and Fouled Operation

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

Figure 10—Modular Waste Heat Boiler Configurations

2) The most serious result of this overperformance is high steam production from the steam generator and high steam temperature from the superheater. This can cause superheater tube metal temperatures to be higher than designed and/or may cause excessive amounts of attemperator spray water to be consumed. This may result in steam purity issues if the spray water quality is poor.

3) Also, the flue gas temperature exiting the economizer can be up to 28 °C (50 °F) lower than design due to evaporator and economizer overperformance, and this needs to be considered in the design of downstream equipment.

b) Flue Gas Velocities

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

4.3.8.4.2 Screen

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

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

4.3.8.5 Mechanical Design Details

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

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

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

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

4.4 Fuels Fired in Industrial Steam Boilers

Historically, the primary fuels fired in most refinery and chemical plant steam boilers were No. 6 fuel oil, commonly called “Bunker C,” natural gas, and plant byproduct gases, as these fuels were commonly available. Beginning in 1970, emissions regulations began and in some areas NOx reductions became mandatory. The first trend in the industry was to convert the oil fired boilers to gas, as No. 6 fuel oil contains fuel bound nitrogen. When burned, a portion of the fuel-bound nitrogen converts to NOx; that fuel-bound (or fuel sourced) NOx can exceed the NOx generated from the thermal effects alone. Natural gas fuel has often replaced No. 6 fuel oil for its economic, environmental, and technological advantages. Section 6.5 describes the common fuels, both gas and liquids, used in refineries and chemical plants. Solid fuels are not reviewed as their use in these facilities is rare.

4.5 Igniter Management System

Given the extensive acceptance of NFPA 85 in the boiler industry, it seems logical that we should use extreme care in correlating these two important safety standards such that engineers and operators who work with boilers may not be confused by terminology used in API 538 and in NFPA 85 (2011) or previous editions. In many cases confusion will arise from the time of the original boiler design, where a clear decision has to be made by the end user concerning which standard to apply for their company’s power boilers. To this effect, the NFPA 85 igniter classifications used for many years are used in API 538 to clearly address the ways igniters can be used. A summary of these igniter classes, as per NFPA 85 (2011), Sections 3.3.85 to 3.3.85.4, is as follows.

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

b) Class 1 Igniter—An igniter that is applied to ignite the fuel input through the burner and to support ignition under any burner light-off operating condition. Its location and capacity are such that it will provide sufficient ignition energy, generally in excess of 10 % of full load burner input, at its associated burner to raise any credible combination of burner inputs of both fuel and air above the minimum ignition temperature.

c) Class 2 Igniter—An igniter that is applied to ignite the fuel input through the burner under prescribed conditions. It is also used to support ignition under low load or certain adverse operating conditions. The range of capacity of such igniters is generally 4 % to 10 % of full load burner fuel input.

d) Class 3 Igniter—A small igniter applied particularly to fuel gas and fuel oil burners to ignite the fuel input through the burner under prescribed light-off conditions. The capacity of such igniters generally does not exceed 4 % of the full load burner fuel input.

e) Class 3 Special Igniter—A special Class 3 high energy electrical igniter capable of directly igniting the main burner fuel.

See Table 1 for a concise summary of these NFPA igniter classes.

The end user shall ensure that igniters are tested with the ignition subsystem in service to be certain that they meet the class requirements.

It shall be kept in mind that one reason for using a Class 1 or Class 2 igniter is simply for operational flexibility, such as the ability to extend the turndown of the boiler for curing refractory with igniters only in service, and for low-load operation where a boiler is kept in a warm standby condition so that it can quickly be brought into service.

How long an igniter is allowed to stay on depends on its classification and its ability to operate continuously. From these definitions the allowable ignition trial period before generating a burner trip is determined. Class 3 and 3S igniters usually have short trial periods, as short as 15 s to 20 s. This is one reason why the piping length from the igniter or burner shutoff valves to the igniter or burner should be kept to a minimum distance. Minimizing this distance minimizes the fuel volume left in the pipes when the safety shutoff valves (SSVs) close such that residual fuel in this piping will not enter the furnace under gravity. The trial period for the associated load burner will also be determined

Table 1—Igniter Properties Summary

Class per NFPA 85 (2011)	Can Be Used for a Class	Igniter Heat Release	Capable of Continuous Operation	Ignition of Load Burner	Capable of Supporting Ignition	Main Burner Turndown	Main Burner Fuel
1	2 or 3	≥10 % of burner heat release.	Always capable of continuous operation.	To ignite the burner under any burner light-off operating conditions.	Supports continuous ignition under any burner light-off operating conditions.	Can be used to extend the turndown range of the main burner.	Coal, coke, coal slurry, wood, fuel oils, and fuel gases.
2	3	>4 % to ≤10 % of burner heat release.	Always capable of continuous operation.	To ignite the burner under low load or certain adverse operating conditions.	Supports ignition under low load or certain adverse operating conditions.	Shall not be used to extend the turndown range, but can support ignition under low loads or adverse operating conditions.	Coal, coke, wood, fuel oils, and fuel gases.
3	Class 3 only	≤4 % of burner heat release.	For intermittent use only, or continuous for specific cases.	To ignite the burner only under prescribed light-off conditions.	Not used to support the burner.	Shall not be used to support ignition or to extend the turndown range.	Fuel oils and fuel gases.
3S	Class 3S only	Not applicable, typically 12 Joules per spark.	Only for intermittent use.	To ignite the burner only under prescribed light-off conditions.	Not used to support the burner.	Not used to extend the turndown range.	Fuel oils and fuel gases.

from both the concern for introducing a combustible fuel mixture into a furnace without an adequate igniter flame present to ignite it; hence if a Class 3 igniter is used and a main flame is not proven within NFPA 85 guidelines, the burner and the igniter have to be shut down.

If at least one Class 1 or Class 2 igniter is proven in a furnace with a single or multiple burners, and the associated burner fails to light under normal prescribed conditions, then only that burner is shut down. These igniters that are lit in the furnace are not shut down, and there is no need to purge the boiler. Another burner can be ignited, while the operators determine the reason for the ignition failure on the previous burner.

Another firing mode that has been used in package boilers and fluidized bed boilers is to fire multiple burners as a group in the "unison" firing mode. In this mode of operation the burner group being fired in unison has to be considered as a single burner or igniter, as the case may be. This mode of operation introduces further operating constraints in designing a set of burner and igniter SSVs for the burners or the igniter group associated with those burners. Keep in mind that operational flexibility in these boilers can be realized by using individual Class 1 or Class 2, while still configuring the main burner group for unison firing mode.

In addition to these issues, many modern burners have a configuration where a Class 1 igniter is an integral part of the burner. In such situations, a careful study of the burner design will eliminate the need for a separate igniter, and possibly a separate igniter valve train. Again, the burner vendor has to demonstrate the performance of this compound igniter burner system.

4.6 Burner Management Systems

4.6.1 General

API 538 should not be applied exclusively as a basis for BMSs. It should be used in conjunction with NFPA 85. For those that apply NFPA 85 to industrial fired boilers in the refinery and petrochemical industry, API 538 provides supplementary guidance for boiler and combustion system hazards. See Section 1 for boiler types covered by API 538.

In contrast to API 538, NFPA 85 is broad, comprehensive, and wide-ranging. NFPA 85 covers multiple burner boilers, single burner boilers, fluidized bed boilers, fundamentals of combustion, systems hazards, HRSGs and other combustion turbine exhaust systems, pulverized fuel systems, and stoker operations.

As indicated in NFPA 85, Chapter 1, “The purpose of this code shall be to contribute to operating safety and to prevent uncontrolled fires, explosions, and implosions in equipment. This code shall establish minimum requirements for the design, installation, operation, training, and maintenance of pulverized fuel systems, boilers, HRSGs, combustion turbine exhaust systems, and their systems for fuel burning, air supply, and combustion products removal. This code shall require the coordination of operating procedures, control systems, interlocks, and structural design. This code shall not be used as a design handbook. A designer capable of applying more complete and rigorous analysis to special or unusual problems shall have latitude in the development of such designs. In such cases, the designer shall be responsible for demonstrating and documenting the validity of the proposed design.”

NFPA 85 is not a mandatory requirement by all local governing authorities.

4.6.2 Hazard Analysis

With the current release of NFPA 85 (2011), Annex A.4.11 has been updated to include hazard analyses that are consistent with current practices in the refining and petrochemical industry.

Utilizing the equivalency provision in NFPA 85 (2011), Section 1.5, alternative designs that meet the requirements of NFPA 85 may be achieved where all the following are provided per NFPA 85, Annex A.4.11.

a) Approval of the authority having jurisdiction (AHJ).

b) A documented hazard analysis that addresses all the requirements of NFPA 85.

c) A documented life-cycle system safety analysis that addresses all requirements of NFPA 85 and incorporates the appropriate application-based safety integrity level (SIL) for safety instrumented systems (SIS). One methodology for achieving a life-cycle system safety analysis is to use a process that includes SIL determination and a SIS design and implementation consistent with the ISA 84 standard series.

As an industry consensus document, API 538 may assist in defining a recognized and generally accepted good engineering practice (RAGAGEP) for the application of instrumentation, control, and protective functions to boilers. However, hazard analysis and SIL assignment are fully independent issues. While this document provides the functional safety basis for protective functions, there is no explicit or implicit recommendation to assign a SIL to a protective instrumented function (PIF). A PIF is classified as a safety instrumented function (SIF) if a SIL is assigned. Facilities that desire to assign a SIL to a SIF should follow the guidelines stated within ANSI/ISA 84.00.01-2004 (IEC 61511-1 Mod).

Some in the industry [i.e. contractors, original equipment manufacturers (OEMs), and vendors] regard NFPA 85 as a document to be strictly followed. However, NFPA 85 (2011), Section 1.3.2 states “This code shall not be used as a design handbook.” NFPA 85 recognizes that a competent designer and/or hazard assessment team should evaluate the hazards and allocate protective functions to mitigate the hazards. Where special problems arise, a competent designer is given the latitude to resolve these issues with a documented basis to the owner/operator. For additional clarification, see 7.2.3.

4.6.3 Documenting the Validity of the Proposed Design

NFPA 85 is a prescriptive, minimum safety standard to be used by competent designers and is not a design handbook. Competent designers are given the latitude to address special or unusual problems provided they document the validity of the designs where such problems exist (NFPA 85, Section 1.3). Additionally, the equivalency section in NFPA 85, Section 1.5 states that “Nothing in this code is intended to prevent the use of systems, methods, or devices of equivalent or superior quality, strength, fire resistance, effectiveness, durability, and safety over those prescribed by this code.”

In contrast, API 538 is a performance-based recommended practice that provides options to mitigate specific process hazards and forms a basis for justifying special designs to the AHJ when these designs deviate or diverge from the prescriptive requirements in NFPA 85.

4.6.4 Impact of Loss of Steam to Critical Process Equipment

Implementation of NFPA 85 requires a competent designer to properly integrate the individual components of a protective function (input sensors, logic solver, and final elements) into a comprehensive protective system. The start-up permissive and tripping interlocks specified in NFPA 85 are limited to those directly associated with the steam generator and combustion system. However, additional steam generator interlocks that are site- or process-specific may be required to ensure safe operation and prevent damage to the steam generator, associated equipment (e.g. outlet piping and superheaters), or critical process equipment.

When designing the BMS and safety interlocks for a steam generator in general refinery or petrochemical service, the overall impact (e.g. safety, environmental, financial) to the plant for loss of steam should be evaluated. Depending on the consequential damage to process, some equipment protection interlocks may not represent good engineering practice for a specific application. In those cases, a high priority alarm may represent the best practice for the benefit of critical production processes and/or critical process equipment.

4.6.5 Operational Limits

The demonstrated operating range of the burner(s) defines the safe operating limits of the combustion system. The operating range shall be determined for specific applications over the full range of anticipated fuels to meet the steam production requirements. The CCS is designed to keep the boiler within the demonstrated operating range. When these operational limits are exceeded, the BMS is designed to take corrective action to safe state by initiating a master fuel trip (MFT).

It is important to recognize that the BMS has limitations. For example, a control loop malfunction may prevent the CCS from maintaining the required air/fuel ratio for safe operation. If the control loop malfunction prevents the process variable (e.g. air or fuel) from crossing the BMS trip set point, the BMS will not be capable of detecting the process hazard. Thus, a CCS to BMS trip may be considered as noted in 7.2.3.14.

For additional clarification on process hazards protection, see 7.5.5.

4.6.6 Fuel-rich Combustion

At operating conditions it is possible for a boiler to accumulate combustibles above the auto-ignition temperature if there is insufficient air to consume all of the fuel. Fuel-rich combustion produces hot flue gas with residual combustibles that can explode if mixed with fresh air too quickly. This is most likely to occur when a furnace transitions suddenly from fuel-rich combustion to fuel-lean combustion (see 7.5.5).

Unburned fuel or products of incomplete combustion leaving the boiler radiant section may be detected by flue gas analyzers (see 7.3.6). When such readings are present, operators should slowly reduce fuel flow.

Flame safeguard instrumentation (see 7.3.7) may provide little, if any, notification to the operator that significant quantities of unburned fuel or incomplete products of combustion are present in the flue gas. If flame is lost at the burner(s), an immediate burner or MFT is required.

Local fuel-rich conditions are not inherently hazardous; air-staged operations create fuel-rich conditions in one or more burners by design and the burner flame is stable and nearly smoke free. One example is when combustion is completed in the upper radiant zone using overfire air or air-rich upper burners (see 6.3).

4.7 Boiler Feedwater Preparation

There are three basic areas of water treatment associated with BFW preparation systems: softening or demineralization of makeup water, oxygen removal, and condensate treatment. Additional information on this subject can be found in Section 9.

Makeup water for industrial fired boilers for refinery and petrochemical service shall, when combined with return condensate, meet ASME guidelines. Makeup water may be pretreated by sodium zeolite softening, ion exchange demineralization (with or without mixed bed polishing), reverse osmosis, or desalination. The feedwater type and quality, as well as the boiler pressure level and desired cycles, are used to determine the most appropriate treatment. In some cases a combination of these treatment processes is used. Fresh water is typically treated by softening, ion exchange demineralization, or reverse osmosis. Brackish water may be treated by reverse osmosis followed by ion exchange demineralization or two-pass reverse osmosis. Seawater is treated by desalination or two-pass reverse osmosis, possibly followed by mixed bed polishing.

Oxygen removal is accomplished mechanically in the deaerator and chemically with oxygen scavengers. The deaerator removes oxygen to approximately 7 ppb, based on the manufacturers design and specification. Oxygen scavengers (either inorganic or organic) are used to complete the removal of oxygen to prevent preboiler (economizers and BFW heaters) and boiler internal corrosion.

Condensate treatment includes addition of neutralizing amines to the deaerator to neutralize CO_2 in the condensate and may include removal of organics and/or ion exchange polishing.

4.8 Boiler Water Quality and Internal Chemical Treatment

Boiler water quality shall meet ASME guidelines based on the pressure of the boiler and the type of makeup water (softened or demineralized). Boiler water quality limits are set to control steam purity, internal boiler corrosion, and deposition. Boiler water quality is controlled by continuous blowdown and addition of internal treatment chemistry. Internal treatment chemistry is added to the BFW line or steam generator to control deposition and corrosion.

The internal treatments are specified based on the BFW quality and the boiler operating pressure. Boilers with softened or reverse osmosis makeup water are typically on residual phosphate or complexing chemistry (chelant/polymer or all-polymer). Boilers with demineralized or desalinated feedwater are typically on congruent pH/PO_4 internal treatment. Additional information can be found in Section 10.

4.9 Steam Purity

Steam purity is the measurement of solids in the steam. Acceptable steam purity is needed to prevent deposits in superheaters and steam turbines, steam line cracking, and to minimize condensate system corrosion. Some processes may also be impacted by steam purity. ASME and turbine manufacturers provide guidelines for steam purity, which is achieved by:

1) controlling boiler water quality, and

2) good steam/water separation in the steam drum.

Additional information is provided in Section 11.

4.10 Boiler Performance

4.10.1 General

- Many criteria are used to assess boiler performance. In some cases, these are established because of regulatory compliance requirements or external, environmental concerns. In other cases, these criteria are set based on internal plant operations and the overall plant performance requirements. Sometimes, these performance criteria are the basis for a guarantee that shall be satisfied. Both the purchaser and the vendor shall understand the basis for the performance criteria and the flexibility either has in agreeing to or enforcing it.

4.10.2 Thermal Performance

The thermal performance of a boiler determines how efficiently the boiler converts heat released during the combustion of fuel into energy contained in steam. ASME *PTC* 4 describes how to conduct tests to accurately characterize a boiler's thermal performance. This document also describes how to quantify the uncertainty of the required test measurements.

- In most cases, the steam outlet conditions (flow, temperature, and pressure) and the inlet streams (water, air, and fuel) are the only parameters defined by the purchaser. The specific performance details, such as efficiency, exit gas temperature, fuel consumption, pressure drops, etc., are defined by the vendor during the proposal and design stages. Formal acceptance testing is then done to measure the actual operation against the vendor's design.

Once the test data is obtained from an existing boiler, the calculations described in ASME *PTC* 4 can be used to calculate the boiler's thermal performance. During the boiler's design phase, these same calculations are used to predict the boiler's thermal performance using design data. Some of these calculations make use of a heat and mass balance applied to a control volume around the boiler.

Using ASME *PTC* 4, a boiler's thermal performance can be characterized with some or all of the following parameters: efficiency, thermal output, steam mass flow, steam temperature/control range, exit flue gas and entering air temperatures, excess air, water/steam pressure drop, air/flue gas pressure drop, air infiltration, energy input, fuel, air, and flue gas flow rates.

As noted in ASME *PTC* 4, a boiler's output is defined as the "energy absorbed by the working fluid that is not recovered within the steam generator envelope." This energy is the amount of heat necessary to produce the desired steam flow at a specific temperature and pressure from a specific set of boundary conditions for the air, feedwater, and fuel.

If a new boiler is to be designed to operate over a range of loads, its thermal performance at each desired load should be calculated during the design phase. These results may then confirm or modify the new boiler's planned operation.

Boiler purchase contracts often have guarantee terms defined for the measurement and acceptance of the unit with regard to defined boiler performance criteria.

It is recommended that acceptance testing of new boilers be conducted as soon as practical after initial operation. Formal acceptance testing of a boiler is challenging and time consuming when done properly. In many cases, the formal testing is waived based on "acceptable" operation and meeting the design steam production conditions. In addition to acceptance testing, routine performance tests are also recommended to ensure boiler performance does not deteriorate over time.

4.10.3 Steam Purity

Steam purity performance is typically not measured on a regular basis unless there is some reason to suspect a problem. Steam purity measurements are often made soon after the boiler is initially commissioned to determine that specified values are being met when the boiler is new. Proper steam sampling facilities are necessary to ensure the sampling and testing of steam samples is meaningful.

ASME *PTC* 19.11 describes how to properly and accurately sample and analyze water and steam samples. Also, please refer to Section 11 of this document for additional information regarding expected steam purity and proper isokinetic nozzles for steam sampling per ASTM D1066-97.

Two additional items to pay attention to are:

a) make sure the sample is running "undisturbed" for at least 30 min prior to collecting a grab sample,

b) only collect the high purity steam sample in a sodium-free (triple rinsed with high purity distilled water) collection bottle.

Omitting these steps can invalidate the test results, even when all other steps are done correctly.

4.10.4 Emissions Performance

Emissions performance is the one test that is rarely omitted. Most locations shall confirm the performance of the boiler with respect to at least one emissions criterion. Because of the regulatory requirements, most of the boilers are equipped with continuous emission monitoring systems (CEMS) to document the boiler emissions for the regulated species. Although nitrogen (NOx) and sulfur oxides (SOx) are the most commonly monitored emissions, some facilities are also required to monitor particulates, opacity, CO, and volatile organic compounds (VOCs).

Refer to 6.3.7 of this document for information regarding emissions control using specialized burners and the expected NOx levels from various control strategies. Also refer to 7.3.6 for information regarding flue gas analyzers, including CEMS. Finally, Annex E provides further discussion of emissions controls and fuel selection.

4.10.5 Noise

In general, noise from the boiler itself is not a significant concern. However, there are several auxiliary items supplied with the boiler that may generate excessive noise levels. Although the ductwork and the boiler itself may produce a constant low-level noise, the most common source of continuous noise is the FD fan (also the ID fan, if supplied). The FD fan intake and the fan driver typically produce unacceptable noise levels that shall be controlled. Silencers are normally included in the air inlet duct and the intake is elevated to reduce noise at ground level. Control valves associated with feedwater and desuperheating may also generate high noise levels. Intermittent or infrequent loud noise comes from start-up vents and pressure-relief valves. Silencers are typically provided for the start-up vents. Another intermittent noise source is a steam safety valve release to atmosphere. As an intermittent source, this noise can be treated differently than other boiler noise sources, e.g. warning signs requiring double ear protection in the safety valve vicinity. Alternatively, this intermittent noise source may be required to meet the same noise limits as other continuous noise sources, e.g. requiring a valve discharge silencer.

The general noise limit is commonly set at 85 dB(A), but some plants may require different values depending on the boiler location. High noise sources, like the FD fan, may be allowed to operate at 90 dB(A) with a requirement for hearing protection in the area. The start-up vent silencer is usually required to meet the 85 dB(A) limit at grade to allow the vent to be open for an extended period of time.

Because of the impact of the surroundings on the noise levels generated by equipment, most of the items are shop tested or certified to meet a noise level standard. Field testing is typically only done if there is a problem or concern for the noise of the item.

Refer to API 560, Annex I, for information and guidance regarding the measurement of noise emanating from fired process heaters. Similar measurements would be appropriate for a boiler.

4.10.6 Rate of Load Change and Turndown

4.10.6.1 Rate of Load Change Testing

When boilers are used in a centralized facility to supply steam to the general plant, they are often expected and required to be able to accommodate the varying load conditions in the plant. This often requires these boilers to be able to operate with rapid load changes. They shall increase their steam production when a process steam producer stops making steam or when a heavy steam user comes online. Although usually less of a problem, these boilers shall also be able to handle rapid load reductions when a steam using process drops off or when an auxiliary steam producer comes online.

If the magnitude and frequency of these load changes can be predicted or estimated by the purchaser, the load change requirements can be established as part of the overall boiler performance. If not specifically required, the boiler vendor may identify a recommended rate for the load changes the boiler can tolerate.

In order to test the boiler regarding its ability to handle load changes, it is necessary to establish the conditions required for the performance. Steady state operation at some low steam production level is established and an instantaneous steam demand condition is created. The boiler's automatic response to this load change can then be documented. Specific issues or limitations to watch for include:

a) main steam header pressure drop (minimum pressure);

b) boiler steam drum level change (max and min);

c) FD fan response [damper position (or driver speed) and air flow];

d) fuel flow and burner operation;

e) emissions and excess air variations.

Similar testing and monitoring can be done for the load reduction test.

Unless the boiler trips or some mechanical limit is reached or exceeded, acceptance of the boiler's response to a rapid load change is often subjective. The acceptance test for this criterion is "did the boiler continue to operate throughout the load change test at the load rate change specified."

4.10.6.2 Turndown Testing

• There are two turndown conditions that may be tested for a boiler as part of performance testing. The most common, "boiler turndown," is usually defined as the lowest steam production (at design pressure) that the boiler can achieve and still maintain the required (specified) steam temperature. Another turndown condition that may be required by the purchaser is to confirm the minimum stable steam production (or boiler operation) at design pressure with reduced outlet steam temperature. These turndown conditions can be specifically tested as part of the boiler performance testing. The specific turndown requirement should be specified by the purchaser during design.

To test the first turndown condition, the purchaser reduces the steam production from the boiler to the point at which the final (outlet) steam temperature begins to drop. At this condition, the desuperheating water flow should be off. As the steam flow is reduced further, there is insufficient heat input being provided to maintain the steam temperature (superheat).

To test the second turndown condition, the purchaser will reduce the steam flow to the "turndown," or minimum condition, and evaluate the general performance of the boiler. At this low steam production, the excess air may be well above the design operation due to limited ability to reduce air flow sufficiently to maintain low excess air (LEA) operation.

Other turndown criteria for specific auxiliary items, such as burners, attemperators, fans, and fuel supply trains, may need to be tested separately in the shop prior to shipment or in the field without the boiler in service. Refer to the specifications for the component in question to determine the suggested methods for testing.

5 Water Tube Boiler Components

5.1 Pressure Parts—Superheaters/Attemperators

5.1.1 Purpose

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

Small superheaters are sometimes installed to add 14 °C to 28 °C (25 °F to 50 °F) of superheat to steam in order to prevent condensation from forming in the steam distribution system.

Attemperators are used to control the final steam temperature by introducing a controlled amount of water into the steam in order to achieve a desired set point temperature. Attemperators are also referred to as desuperheaters.

5.1.2 General Description

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

Radiant superheaters (not common in industrial boilers) are located within the furnace and have a decreasing temperature versus load characteristic. Consequently, radiant superheaters generally have minimal attemperation requirements at full load. Convective superheaters have an increasing temperature versus load characteristic. Therefore, convective superheaters typically have a high attemperator flow at full load. Radiant-convective superheaters configured either in series, or as two or more stages, receive heat by both radiation and convection and consequently have a relatively flat temperature versus load characteristic. Radiant-convective superheaters, therefore, have reduced attemperator water requirements.

In low-pressure boilers operating at 2.8 MPa (ga) [400 psi (ga)] and below, small amounts of superheat can be attained by passing saturated steam through a pressure-reducing station. Superheat achieved by this method typically ranges from 2.8 °C to 14 °C (5 °F to 25 °F) above saturation.

Superheaters may be arranged with multiple passes transverse (perpendicular) to the flue gas flow, as well as multiple stages in the same direction of (parallel to) flue gas flow. Additionally, steam flow may be counter to, or co-current (parallel) to, flue gas flow. The arrangement of passes and stages are set to provide a reasonable pressure drop and sufficient steam mass flow per tube to limit tube wall temperature.

Attemperator systems usually consist of a flow control valve, spray nozzles within the steam line, a downstream temperature transmitter, and a controller. The location of the spray nozzles can be at the superheater outlet (terminal attemperation), between superheater stages (inter-stage attemperation), or between passes (inter-pass attemperation). Feedwater is typically used as the cooling medium as long as the water quality is adequate to prevent contamination of the final steam or damage to the superheater in the case of inter-stage or inter-pass attemperation. When feedwater quality is not sufficient a “sweetwater condenser” may be used to provide high-quality water to the attemperator. These condensers take saturated steam from the steam drum and condense it in a shell-and-tube exchanger utilizing feedwater as the cooling medium on the tube side. A condensate storage tank with sufficient capacity is typically provided to ensure an adequate supply of water during operating transients. Methods of non-direct contact attemperation include cooling the superheated steam in heat exchangers. These non-direct contact attemperators are used where BFW is not clean enough to provide the required purity of superheater steam. One of the most common types of non-direct contact attemperators is an in-drum coil in which the superheated steam is cooled by transferring heat to the saturated steam/water mixture in the steam drum. In-drum coils may also be located in the mud drums if the mud drum is of sufficient size to accommodate the coil. Superheated steam may also attemporate by cooling it in an external shell-and-tube type heat exchanger with the incoming BFW as the cooling side. These types of non-direct contact attemperators often use a three-way valve controlled by steam temperature to maintain final steam temperature.

- Adequate superheat temperature margin above saturation is recommended for all operating conditions. Attemperator (desuperheater) spray flow rate required to maintain the superheat margin is dependent on the specified boiler control (operating) range. Excessive attemperation spray is not recommended and should be avoided, if possible. The purchaser should decide on the control (operating) range and the maximum attemperator spray flow rate based on a percentage of MCR, minimum MCR rate (control range) to meet design superheat temperature, and superheat margin above saturation temperature. Typical values are 7 % MCR, 50 % to 60 % MCR, and 15 °C (25 °F) above saturation, respectively.

It is standard practice not to design a superheater for a no-flow condition.

5.1.3 Mechanical Details

Superheaters may have tubes in hairpin loops connected in parallel to inlet and outlet headers. They may also be of the continuous tube design in which each element has tube loops in series between inlet and outlet headers. In either case, they may be designed for drainage of condensate or may be in non-drainable pendent arrangements. Vertical tube superheaters are typically supported from the headers and may contain steam-cooled wrapper elements or water-cooled spacers to maintain proper tube spacing. Horizontal tube superheaters are typically supported via lugs welded to boiler tubes or via steam-cooled support tubes. Steam-cooled support tubes may be either an independent stream or integral to the element it supports. Superheater elements and supports shall be designed to accommodate the differential expansion caused by dissimilar materials and different operating temperatures. The maximum differential expansion may occur during start-up when the boiler pressure parts are cold and the superheater is exposed to hot flue gas without any cooling steam passing through the elements.

Tube-skin thermocouples may be attached to the superheater tubes as a monitoring device. The suggested locations are immediately downstream of the inlet header, upstream and downstream of the attemperator, and on the superheater terminal pipe.

Attemperators come in many types, from simple spray nozzles to complex variable venturi styles. The selection of the appropriate type is dependent on the turndown range required, the control accuracy needed and the available spray water pressure. The design of the spray nozzles shall minimize thermal stresses created by the temperature differential between the steam and the incoming water. In addition, the downstream piping may require a thermal liner to protect the pressure piping from damage due to impingement of water droplets.

Superheater tubes and their supports shall be designed for vibration-free operation.

5.1.4 Metallurgy

Superheater tubes are generally carbon steel, 1-$^{1}/_{4}$Cr-$^{1}/_{2}$Mo (T-11), 2-$^{1}/_{4}$Cr-1Mo steel (T-22), 9Cr-1Mo-V (T-91), and 18CR-8Ni (304H) grade stainless. The material selection depends on the temperature and pressure of the application. Typically, the governing criterion is based on a minimum tube wall thickness, as calculated from ASME *BPVC*. Excessive tube wall thicknesses are avoided by selecting a higher grade material. Tubes used in the steam superheat section are generally higher alloys for improved strength and resistance to thermal oxidation. The selection depends on the metal temperature and operating stress of the tube during normal operation and also its resistance to damage during start-up. The orientation of steam flow relative to the flow of hot gases over the tubes can have a dramatic effect on the operating temperature of the tube wall. Counter flow arrangements require the least heating surface, but have the highest tube metal temperature; parallel flow designs have lower metal temperatures, but may not be practical for some high steam temperature applications due to arrangement considerations.

The design metal temperature for a superheater tube is equal to the calculated tube outer wall temperature plus a design margin. The boiler vendor includes this design margin, which should consider steam and flue gas flow and temperature unbalance effects. The tube midwall temperature is used to determine the allowable stress that is used in the calculation of the tube wall thickness. The midwall temperature is the average of the inner and outer wall temperatures.

Tube material temperature limits can be found in ASME *BPVC* Section II, Part D.

Generally, the attemperator metallurgy matches the piping to which it is installed.

5.1.5 Operation

In general, superheaters are located in areas of comparatively high flue gas temperatures, and as a result, the danger of oxidizing or burning the superheater tubes always exist. It is important to maintain steam flow through a superheater at all times and in sufficient quantity to absorb and carry away the heat picked up by the tubes.

Non-drainable or pendent arrangements are very susceptible to tube failure due to overheating on start-up. Water collected in the pendant shall be slowly vaporized to ensure a flow path for the steam. If the boiler is heated too rapidly, some pendants will not clear of liquid; therefore, steam will not flow and the tube will overheat and fail. Special start-up instructions should be taken into consideration with this type of arrangement. Superheater element outlet thermocouples may be installed to monitor if all elements are clear and passing steam.

Prior to placing a superheater into service, all drains and vents shall be opened to clear headers of as much water and entrained air as possible. The drains and vents shall remain open until the steam pressure reaches 34.5 kPa (ga) [5 psi (ga)] or until a definite flow of steam through the superheater has been detected. At this time all the drains and vents should be closed, except for the vent on the outlet header. The vent on the outlet header shall remain open until the unit is passing steam into the outlet piping.

Placing a cold boiler with a superheater into service requires moderate firing of the combustion equipment in such a way that the heat is as uniformly distributed over the superheater tubes as possible. During the start-up process the steam temperature leaving the unit should be below the temperature during normal operation. If at any time during unit start-up, the outlet steam temperature approaches the maximum design steam temperature, the firing rate is too high.

During normal operation the superheater outlet temperature shall be monitored to ensure that any final steam temperature control equipment is functioning properly. If final steam temperature cannot be controlled to within the limits of the design temperature, the firing rate shall be reduced until the system can be brought under control and the superheater tubes protected from excessive heat exposure. Boiler turndown can affect the ability to control superheater outlet steam temperature.

All superheater arrangements are susceptible to failure due to steam impurities plating on the tube internal surfaces. Such impurity plating insulates the tube metal from the superheated steam, thereby raising the superheater metal temperature above design conditions. Therefore, the steam purifying equipment shall be maintained to operate at its optimal efficiency to minimize the carryover of boiler water solids into the superheater tubes.

Attemperator outlet temperature should be monitored to ensure there is sufficient residual superheat based on attemperator design limits. This will ensure there is no moisture carried into the downstream piping. If the attemperator is not being used, make sure the water shutoff valve is closed to prevent unintended water leakage through the control valve.

The steam at boiler outlet is usually protected from too high a temperature. The boiler load has to be reduced if the steam temperature is too high (e.g. in case of a malfunction of the attemperator). The same action may be taken if an intermediate steam temperature becomes too high.

Refer to Section 7 for more detailed control functions.

5.1.6 Maintenance

During the routine boiler inspection, the superheater should be inspected for signs of material degradation. On the outside of the tubes any scaling of the tube surface, sagging of elements, changes in tube OD, and the condition of all tube supports should be noted and recorded. A sampling of tube wall thicknesses should be performed periodically to determine the material loss rate. This information may be used to predict when superheater tube replacement will be necessary and will help prevent emergency shutdowns (ESDs) for repairs. This is especially true if the fuel fired is corrosive to the tubes or has abrasive ash content. Tube inside surfaces should be inspected for excessive corrosion or for deposition of boiler water solids. Any tubes that show excessive deterioration shall be replaced prior to putting the unit back in service.

Refractory baffles used to either protect portions of the superheater from direct furnace radiation or used to direct the flow of flue gases through the superheater should be checked for proper location and condition. Improperly located refractory can lead to overheating of individual elements and overall poor performance of the superheater.

Attemperator water shutoff valves should be checked to ensure they achieve tight shutoff. Any unintended leakage of spray water into steam piping can damage a superheater if the water enters a tube and creates differential temperatures between any of the tubes.

5.1.7 Troubleshooting

See Table 2 for superheater troubleshooting options.

Table 2—Troubleshooting Superheaters

Trouble	Causes	Solutions
Low steam temperature at desired operating conditions.	Outside fouling. Scale on inside of tubes. Change in fuel characteristics. Change in burner excess air or FGR levels. Too much water introduced through the desuperheater.	Sootblow or water wash tubes. Chemically clean tubes. Check fuel air ratio of burners. Check desuperheater control valve operation. Add superheater tubes.
High steam temperature at desired operating conditions.	Low emissions, staged combustion burners can significantly increase superheater steam temperatures due to increase in furnace exit gas temperature. Desuperheater water flow is insufficient.	Remove superheater tubes. Check desuperheater control valve operation.
Tube internal corrosion.	Deposits on inside surface of tubes.	Check that drum internals are properly designed and installed.
Scale on inside of tubes.	Water carryover.	Check drum internals properly designed and installed. Chemically clean tubes.
Steam/water balance shows water loss.	Tube leak.	Shut down to investigate and repair.

5.2 Pressure Parts—Steam Generating Tubes

5.2.1 Purpose

The purpose of the steam generating tubes (riser/evaporator tubes) is to carry water and the water/steam mixture flowing from the lower drum (mud drum) to the steam drum. During its path, steam is generated by convection heat transfer to the bank tubes and by radiation to the furnace and screen tubes.

5.2.2 General Description

The steam generating tubes are divided between the boiler bank tubes and the waterwall furnace tubes. Radiation is the primary heat transfer mechanism in the furnace. Convection heat transfer is the primary mechanism in the boiler bank tubes. Vaporization takes place in the riser/evaporator tubes, and the steam/water mixture generated has a density less than the density of the water in the downcomers. This density difference and the static pressure head generated by the height difference between mud and steam drums is the driving force for the natural flow (circulation) through the boiler's steam generating tubes. Higher steam pressure boilers have a smaller density difference than lower pressure boilers.

5.2.3 Mechanical Details

- The purchaser shall specify the acceptability of electric resistance welded (ERW) steel. The ERW tubes are limited to economizers and evaporative tubes. Seamless tubes can be used anywhere in a boiler.

  All steam generating tubes shall have a minimum OD of 38 mm (1.5 in.). Normally, the tube size is no larger than 76 mm (3.0 in.).

- Steam generating tube material shall be selected based on the highest anticipated metal temperatures and flue gas composition. Typically carbon steel is used for evaporator tubes.

  Tube and header configurations shall allow free natural circulation of water and steam in the proper direction at all loads, and be installed to allow complete draining of all tubes and headers.

- Tubes to boiler drums are attached by rolling to drums. Tube holes in steam and mud drums should be grooved (serrated) to provide a more reliable seal. The tubes may be seal welded or fully welded if deemed appropriate by the purchaser due to pressure considerations or specific applications.

  The recommended minimum wall thickness of tubes is 4 mm (0.15 in.) for 76 mm (3 in.) OD tubes and 3 mm (0.120 in.) for 51 mm (2 in.) OD tubes and smaller.

  Horizontal tubes (oriented with less than 3° slope) located in furnace floors shall be covered by firebricks, 50 mm (2 in.) thick, minimum.

  All outside waterwalls and furnace division walls shall be of the membrane wall design.

  For boiler tubes, temperatures are maintained at known levels by providing a sufficient flow of water to prevent the occurrence of critical heat flux (CHF) phenomena. An adequate saturated water velocity shall exist for each tube. Areas where CHF is more likely to occur are high heat flux zones and sloped tubes that receive heat from the top.

5.2.4 Operation

Based on their configurations, steam generating tubes are mainly divided into riser, division wall, side wall, and D-shaped tubes. Steam generating tubes connect the mud (lower) drum to the steam drum (top). The driving force for the flow in the steam generating tubes is the density differential between water in the downcomer tubes and water/steam mixture in the steam generating tubes. For each tube configuration (circuit), different pressure loses are encountered due to variations in tube length, size, shape, and number of bends, which influences the natural circulation. There shall be ample circulation in every circuit to ensure sufficient cooling of tubes by keeping the tube surface wetted continuously and maintaining an efficient heat absorption rate. If improper circulation exists, departure from nucleate boiling (DNB) can occur, resulting in film boiling and possible steam blanketing, which is to be avoided. Steam blanketing in horizontal or sloped tubes will act as an insulting layer to the cooling steam/water mixture, resulting in overheating of the top side of the tube. Another problem associated with DNB is the formation of deposits on the internal heat transfer surface, as the washing effect is lost. Deposits will also act as an insulting layer and eventually will cause overheating and tube failure.

DNB occurs when heat flux becomes greater than, or equal to, the CHF value. Figure 11 depicts typical boiler circulation ratios versus steam drum operating pressures.

The dimensions and design of furnace wall steam generating tubes shall be such that complete combustion of fuels takes place within the furnace limits without flame impingement on sidewalls, roofs, and front walls.

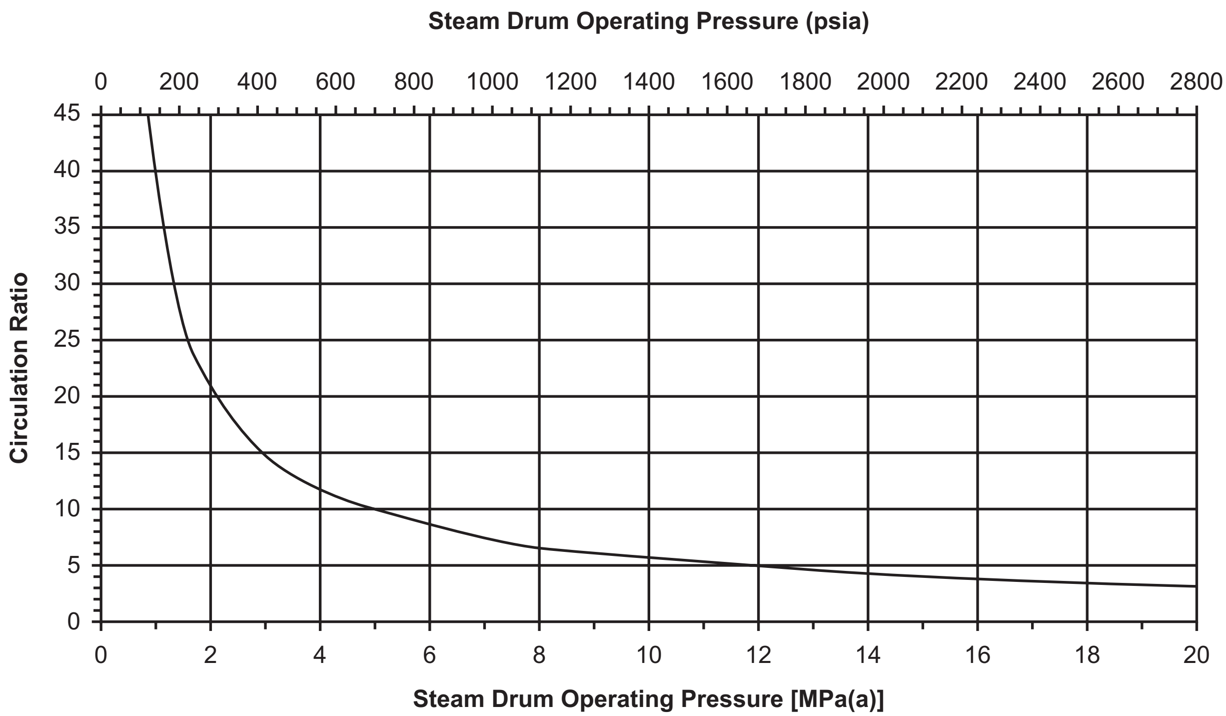


Figure 11—Typical Circulation Ratio vs Steam Drum Operating Pressure

5.2.5 Maintenance

Maintenance of the boiler consists of keeping the tubes clean. External cleaning generally consists of sootblowing on a regular basis. The frequency of the cleaning is based on the extent of fouling and the extended surface arrangement. In some situations water washing is utilized. Since the residue of heavier fuels may be hygroscopic, it is imperative that water washing remove all the deposits to prevent an insoluble mass from being baked onto the tubes when the boiler is brought back online. It is also important to maintain a clean surface on the inside of the tubes. Scale removal is accomplished by chemical cleaning. When damage of tubes or extended surface is indicated, the damaged tubes should be replaced. Periodic inspection of the lining and tube supports should also be performed.

5.2.6 Troubleshooting

See Table 3 for steam generating tube troubleshooting options.

Table 3—Troubleshooting Steam Generating Tubes

Trouble	Causes	Solutions
Decreased efficiency.	Tubes fouled. Scale on inside of tubes. Excessive flue gas flow.	Sootblow or water wash tubes. Chemically clean tubes. Check burners fuel air ratio.
Tube internal corrosion.	Water not deaerated. Incorrect pH.	Check deaerator. Check water pH.
Steaming in the economizer.	High flue gas inlet temperature. Feedwater bypassing.	Clean tube surfaces of upstream sections (boiler and superheater). Fully close bypass valve.
Steam/water balance shows water loss.	Tube leak.	Shut down to investigate and repair.
Tube blistering and failure.	Scale on inside of tubes. Direct flame impingement.	Chemically clean tubes. Check burner flame pattern.
Scale on inside of tubes.	Improper water chemistry. Departure from nucleate boiling.	Verify, and if necessary, change water treatment/water chemistry program. Confirm boiler circulation.

5.3 Pressure Parts of Economizers

5.3.1 Purpose

The purpose of the economizer section is to improve the thermal efficiency of the boiler by utilizing the waste heat in the flue gas to preheat BFW. Using an economizer reduces fuel usage, and therefore, lowers the stack emissions mass rate.

5.3.2 General Description

5.3.2.1 General

An economizer is a heat exchanger located in the path of the flue gas downstream of the boiler tubes. It is generally a bank of tubes arranged in rows. The economizer may be initially designed as an integral part with the boiler, or it may be supplied as a free standing item separate from the boiler. It may also be a retrofit item added to an existing boiler.

5.3.2.2 Efficiency Considerations

The boiler may operate with or without an economizer. An economizer is used to increase boiler efficiency. The relative advantage of an economizer will vary based on the operating conditions of the boiler. A high-pressure boiler will have a higher flue gas stack temperature (more waste heat) than a low-pressure boiler since the flue gas temperature will always be higher than the water saturation temperature. As a result, the potential for efficiency improvement is greater and the use of an economizer may be more beneficial in a high-pressure boiler. There may also be incentives for reduction of stack emissions resulting from the addition of an economizer. An economizer may be used alone or in conjunction with an APH to increase the overall efficiency. The economizer will reduce flue gas temperature entering the APH, which can affect the materials of construction and the size of the APH. The use of an economizer will increase the draft losses and shall be considered in the design of the stack and/or fans. Economizer retrofits shall also take into consideration the potential effects on boiler natural circulation due to reduced furnace heat input.

The economizer should be sized to preclude steaming during all specified operating conditions. The maximum economizer outlet water temperature shall be below the steam drum saturation temperature for the expected range of operating conditions. In the event that start-up or upset conditions result in steam generation within the economizer, the steaming condition shall not impair required steam quality, cause vapor lock, cause equipment damage, or otherwise impair boiler operation. Design considerations for the possibility of steaming may include header vent valves, bypass valves, and recirculation of water.

Economizer design should consider whether individual tubes or the entire coil section may need to be replaced.

The economizer coil shall be designed to be completely drainable.

5.3.2.3 Types of Economizers

The most common type of economizer is the conventional type, which uses the sensible heat in the flue gas. The economizer is designed such that the flue gas outlet temperature will remain above the dew point of the flue gas and the economizer inlet feedwater temperature is high enough to prevent condensation of the flue gas. Generally, the BFW is preheated within the economizer to a temperature below its boiling point. Although not recommended, in some instances limited boiling can take place within the economizer. Conventional type economizers can have a variety of different coil arrangements and tube sizes.

Another type of economizer is known as a condensing economizer. In addition to utilizing the sensible heat in the flue gas, the condensing economizer is designed to capture the latent heat of vaporization from the water vapor in the gas and thus produce a higher efficiency. The use of condensing type economizers is not common in refineries or for large boilers, but as the need for higher efficiencies increases, condensing type economizer applications may increase. Condensing economizers are designed such that the stack flue gas temperature is below the flue gas dew point temperature. In order to evaluate whether the condensing economizer is attractive, consideration shall be given to the moisture content and the acid dew point of the flue gas. The best applications for condensing economizers are for boilers firing clean gaseous fuels with low acid dew points. Special materials and construction features shall be considered to deal with the corrosive characteristics of the condensate. In some instances it may be advantageous to use both a conventional economizer and a condensing economizer in series.

5.3.2.4 Dew Point Considerations

When the boiler fuel contains sulfur, acidic solutions will condense out of the flue gas if the flue gas temperature or surfaces in contact with the flue gas are cooler than the dew point of the solution. This can result in excessive corrosion of the tubes. To properly design the economizer, the fuel composition shall be considered along with the temperature of the BFW being used. Either the design shall ensure that the dew point is not reached, or the materials and construction of the economizer and downstream ductwork and stack shall be selected to protect the equipment from damage. In general, the economizer is designed to maintain all metal temperatures above the dew point in order to protect the equipment and flue system. Refer to API 560, Annex F, for minimum recommended temperatures as a function of sulfur in the fuel.

When the boiler is designed to fire an alternate fuel with higher sulfur levels, a water side bypass may be used to protect the economizer tubes. In this case, the economizer coil will be designed so that it can be drained and operated in a dry condition. With this design, water should be carefully reintroduced into the economizer coil, per the manufacturer's recommendation, to prevent thermal shock to the tubes, which typically requires the boiler to be shut down.

Alternatively, and also quite common, the feedwater may be preheated above the acid dew point plus a sufficient temperature margin using a feedwater preheater. The feedwater preheater can be an external heat exchanger (e.g. on steam) or with a heat exchanging coil in the steam space of the steam drum.

Extra gas side cleaning provisions should be considered for economizers operating below the flue gas dew point.

5.3.3 Mechanical Details

5.3.3.1 Conventional Horizontal Tube Type

Economizers are designed in a variety of different configurations. Typically, the economizer will be arranged as rows of tubes situated within a rectangular housing. The tubes are connected to a single inlet and single outlet manifold and are arranged in horizontal continuous rows. The economizer is typically situated between the boiler and the stack. In some arrangements the economizer can be located within the boiler setting. For the best efficiency, the BFW will run through the tubes countercurrent to the flue gas flow. This arrangement results in the least draft loss and surfacing requirements. When ash is expected, consideration should be given to a layout that would allow for the installation of a hopper. The hopper is utilized to collect heavy particles that drop out of the flue gas flow and to collect ash during offline washing of the tubes. Tube spacing should also consider the placement of sootblowers to clean the tubes while the boiler is operating.

Typical tube sizes range from 38 mm to 76 mm (1$^1/_2$ in. to 3 in.) OD, but larger sizes may be used. To achieve the best efficiency, the tubes are generally designed with extended surface area. However, bare tubes are also used, particularly when tube cleaning is a significant consideration. Extended surface tubes are normally finned, but may be studded. Commonly, fins are continuously welded to the tubes using high frequency welding. The fin pitch is a function of the fouling characteristics of the fuel being fired. See Table 4 for general guidelines. Refer to API 560 for recommendations on studded tubes.

Table 4—Typical Economizer Fin Parameters

Fuels (Note 1)	**Square Tube Pitch with Solid Finning** fpm (fpi) (Note 2)	**Staggered Tube Pitch with Solid or Serrated Finning** fpm (fpi)	**Cleaning Provisions Recommended**	**Fin Minimum Thickness** mm (in.)	**Fin Maximum Height** mm (in.)
Natural gas only	236 (6) or more	236 (6) or more	No	1.27 (0.05)	19.05 (0.75)
Natural gas with #2 oil backup	197 (5)	197 (5)	No	1.27 (0.05)	19.05 (0.75)
Natural gas with #4 oil backup	157 (4)	157 (4)	No	1.27 (0.05)	19.05 (0.75)
Natural gas with #5 or #6 oil backup	118 (3)	118 (3)	Yes	1.27 (0.05)	19.05 (0.75)
#2 or #4 oil	118 (4) to 197 (5)	NA	Yes	1.524 (0.06)	19.05 (0.75)
#5 or #6 oil	118 (3)	NA	Yes	1.524 (0.06)	19.05 (0.75)
Heavy residual bunker C or coal tar	98 (2.5)	NA	Yes	1.905 (0.075)	15.875 (0.625)

NOTE 1 Since the chemical composition of refinery gas can vary significantly, refinery gas shall be evaluated on a case-by-case basis.

NOTE 2 fpm: fins per meter, fpi: fins per inch.

Tube and header materials are generally carbon steel. Other materials, such as duplex stainless steels and protective coatings, may be considered when corrosive conditions dictate, e.g. condensing economizers. The economizer tubes may be arranged in rows, either staggered or inline. Tube spacing shall consider cleaning lanes for sootblowers or other cleaning facilities. Generally, clear lanes between fin tips and bare tubes are greater than 25 mm (1 in.), unless clean fuels are used.

- Headers may be located inside or outside of the flue gas stream. When tube sheets are utilized, they shall be designed to reduce flue gas leakage and bypassing.

The maximum (design) economizer tube metal temperature is determined by the boiler manufacturer. To determine the design temperature of a header it is recommended to use the maximum (design) tube metal temperature. See 5.1.4 for the tube metal temperature calculation basis.

Economizer tubes and their supports shall be designed for vibration free operation.

5.3.3.2 Conventional Duct Type

For retrofit applications, smaller economizer units may be utilized that fit within the existing ductwork or stack. These may be designed as helical coils or rows of coils arranged around the inside surface of a duct or stack. The duct type of economizer is often non-repairable, as there may be no access to the tubes. The advantage is that there are minimal requirements for space.

5.3.4 Operation

The operation of the economizer consists of controlling the flue gas flow and the feedwater. Generally, there is no flow control on the flue gas side. In some situations it may be possible to bypass flue gas using dampers. Operation on the water side consists of water conditioning and maintaining sufficient water flow to prevent steaming. Proper treatment of the water is required to prevent rapid internal tube corrosion. For more details on BFW preparation, see Section 9. Since the water flow through an economizer is typically controlled via the steam drum water level control valve, care shall be exercised to ensure that this control valve maintains sufficient flow through the economizer to prevent steaming. Steaming in the economizer can cause damaging water hammer.

5.3.5 Maintenance

Maintenance of the economizer consists of keeping the tubes clean. External cleaning generally consists of sootblowing on a regular basis. The frequency of the cleaning is based on the extent of fouling and the extended surface arrangement. In some situations water washing is utilized. Since the residue of heavier fuels may be hygroscopic, it is imperative that water washing remove all the deposits to prevent an insoluble mass from being baked onto the tubes when the economizer is brought back online. It is also important to maintain a clean surface on the inside of the tubes. Scale removal is accomplished by chemical cleaning. When damage of tubes or extended surface is indicated, the damaged tubes should be replaced. Periodic inspection of the lining and tube supports should also be performed.

5.3.6 Troubleshooting

See Table 5 for economizer troubleshooting options.

5.4 Pressure Parts—Steam Drum, Mud Drum, and Headers

5.4.1 Purpose

The steam drum is the upper drum, which is a pressure vessel located at the upper extremity of a boiler circulatory system in which steam is accumulated, separated from water, and then discharged as saturated steam. The boiler steam capacity plays a major part in determining the size of the steam drum and the internal steam separation equipment.

The more steam production required from the boiler, the larger the steam drum’s length and diameter required to provide more steam separation space. The water drum (mud drum) is a pressure vessel of a drum or header type located at the lower extremity of a water tube boiler convection bank. It receives boiler water from downcomer tubes and distributes the water to waterwall headers, D-tubes, evaporator tubes, and riser tubes in the convection bank. It is normally provided with a blowdown valve for periodic blowing down of sediments accumulated in the bottom of the drum. Headers are pipes or box-shaped distribution pressure containing parts for supplying a number of smaller tubes with water and/or steam. Headers usually are not in direct contact with flame radiation. Lower and upper headers are connected by burner wall and rear wall tubes, making the two furnace walls that are not surrounded by the D-tubes, division wall, and screen tubes.

Table 5—Troubleshooting Economizers

Trouble	Causes	Solutions
Decreased boiler efficiency.	Tubes fouled. Scale on inside of tubes. Excessive flue gas flow. Feedwater bypassing.	Sootblow or water wash tubes. Chemically clean tubes. Check fuel air ratio of burners. Fully close bypass valve.
Tube external cold end corrosion.	Condensation on tubes.	Increase feedwater temperature. Reduce sulfur content in fuel. Replace tubes with corrosive resistant material.
Tube internal corrosion.	Water not deaerated. Incorrect pH.	Check deaerator. Check water pH.
Steaming in the economizer.	High flue gas inlet temperature. Feedwater bypassing.	Clean tube surface of upstream sections (boiler and superheater). Fully close bypass valve.
Steam/water balance shows water loss.	Tube leak.	Isolate economizer if bypass provisions exist and/or shut down to investigate and repair.

5.4.2 General Description

The steam drum is supplied with an internal feedwater distribution pipe, a chemical feed distributor, and a continuous blowdown collection header. Water level control baffling is installed to ensure that all steam released from the generating tubes is released behind the baffles and not through the main steam drum water level. Steam drum internals include steam/water separators. Separators could be labyrinth separators, dry pipe separators, or cyclone separators or chevron dryers, or could be a combination of two types. Each type has certain applications, depending on the required level of steam purity and boiler manufacturer's preference.

5.4.3 Mechanical Details

5.4.3.1 General

A steam drum is of welded construction in accordance with ASME *BPVC* Section I. The steam drum wall may be thicker for the steam drum bottom to compensate for the material removed during the drilling of the tube holes. A steam drum shall be stress relieved, and welded seams are radiographed and hydrostatically tested per code. No extra supporting steel is required.

The manway shall be sized to allow personnel access and removal of steam drum internals as necessary. The thickness of the dished head must take into account the size of the openings in order to meet ASME *BPVC* Section I requirements.

5.4.3.2 Steam Drum Sizing

The following must be observed when sizing steam drums.

a) Margins in the operating pressure (e.g. maximum operating pressure) shall be specified by the manufacturer and shall be taken into consideration when determining the maximum allowable working pressure (MAWP) of the boiler.

b) The inside diameter shall be not less than 910 mm (36 in.) to allow room for access and steam drum internals.

c) The steam space shall be adequately sized to contain steam separation equipment necessary to attain the guaranteed steam purity specified throughout the control range.

• d) The water holding capacity between the different water levels [e.g. NWL, LWL, low level cutoff (LLCO), and high water level (HWL)] shall be reviewed to evaluate the effect of evaporation at MCR with no feedwater flow. The typical steam drum water retention time between the NWL and the LLCO is between 1 and 2 min at MCR with no feedwater flow.

e) The LLCO shall be located above the top of the highest downcomer.

f) A rise in water level (swell) above the NWL resulting from the requirements specified shall not cause a carryover or actuation of the HLCO, if HLCO is employed.

g) A fall in water level (shrinkage) below the NWL resulting from the requirements specified shall not cause the actuation of the LLCO.

Pipe sizes of $1^1/4$ in., 5 in., and 7 in. NPS shall not be used.

A manway shall be provided at both ends of steam and water drums and be provided with hinged covers or davits.

5.4.4 Metallurgy

Drums and headers should not be designed and used as a heat transferring surface. As a result, carbon steel materials are used as permitted by ASME *BPVC* Section I, as shown in ASME *BPVC* Section II, Part D, Table 1A.

5.4.5 Operation

• Steam drums receive BFW from the BFW pumps. The operating pressure in the steam drum shall be higher than the pressure required in the plant supply header to accommodate for the pressure drops across the downstream sections such as the superheater, NRV, and piping. A NWL is maintained at a specified level referenced to the drum centerline.

Four more levels are defined as low water alarm (LWA), low water cutout (LWCO), high water level alarm (HWLA), and high water cutout (HWCO). The boiler will automatically shut down at LWCO. The boiler may shut down at HWCO at the purchaser's option.

5.4.6 Steam Drum Internals

Steam drum internals shall consist of equipment for steam separation, feedwater distribution, chemical feed distribution, and blowdown.

Steam separation equipment shall be designed to meet the purity of steam specified on the data sheet.

Proposals for other types of steam separation equipment shall be included in the boiler manufacturer's proposal and shall be substantiated with test results of commercial units indicating that the steam purity entering the superheater will not fall below that specified on the data sheet.

All internals shall be designed such that they can be removed without cutting.

The design of chemical feed distribution piping shall comply with the following:

a) be extended through steam drums and be of sufficient length to ensure proper mixing of chemicals;

b) be perforated;

c) be closed at the far end, using a threaded cap;

d) be provided with a thermal sleeve;

e) be located in the steam drum to avoid short-circuiting of chemicals into the continuous blowdown collection system.

BFW distribution piping shall be provided and be extended through the steam drum to ensure proper mixing of the feedwater with saturated recirculated water so that thermal shock is avoided.

The design of continuous blowdown internal piping shall comply with the following:

a) be located in the area with the highest concentration of boiler water impurities;

b) be extended as far as possible;

c) be perforated with holes not smaller than 9.5 mm (0.37 in.) or V-notched on the top.

5.4.7 Water Drum Connections

Water drum intermittent blowdown nozzles shall be located on the lowest point of water drums. Drum connections shall be a minimum of 2 in. NPS schedule 160.

Separate drain valves shall be provided at the lowest point of water drums as a means of draining boilers. Long mud drums may require drain/blowdown valves at each end.

5.4.8 Maintenance

Maintenance of the steam drum, mud drum, and headers consists of ensuring that the feedwater conductivity and steam contaminant measurements are kept below specified limits and visually inspecting this equipment on a regular basis during scheduled outages. The steam drums and headers should be free to expand. The insulation on the outside of the steam drum should be inspected regularly. Inspect the exterior of headers for corrosion, erosion, and thermal cracking. The condition of the insulation on the outside of the headers should also be inspected. In addition, inspect all chemical feed and blowdown lines for plugging and leaks. Consult the OEM manual for additional inspection items.

5.4.9 Troubleshooting

See Table 6 for steam and mud drum troubleshooting options.

Table 6—Troubleshooting Steam and Mud Drums

Trouble	Causes	Solutions
Moisture carryover into superheater.	Damage to steam drum internal equipment.	Inspect steam drum internal equipment, review original equipment manufacturer manual, and/or contact manufacturer.
Poor steam purity.	Improper water chemistry in the boiler feedwater.	Verify and, if necessary, change water treatment/water chemistry program.
Foaming of water in steam drum.	Improper water chemistry in the boiler feedwater.	Verify and, if necessary, change water treatment/water chemistry program.
High conductivity levels in feedwater.	Improper water chemistry in the boiler feedwater.	Verify and, if necessary, change water treatment/water chemistry program.

5.5 Furnace Design

5.5.1 Purpose

The furnace may be considered as the heart of the boiler. It performs several important functions in a steam generator, such as ensuring complete combustion of the fuel with minimal generation of pollutants, such as NOx and CO, and that the flue gas is adequately cooled before it enters the other heating surfaces, such as radiant or convective superheaters or evaporator tubes. Since it is a high heat flux zone, proper water circulation shall be ensured inside the furnace tubes to keep them cool. The furnace dimensions shall be such that the burner flame is well contained within the walls of the furnace so that flame impingement does not occur.

5.5.2 General Description

The furnace is generally custom designed based on several parameters discussed below. Considerations need to be taken based on many issues such as emissions, heat flux, casing corrosion, and maintenance.

5.5.3 Mechanical Details

The starting point when sizing a boiler furnace is information on fuels to be fired and emission limits of pollutants such as NOx, CO, and unburned hydrocarbons (UBHCs). The burner suppliers provide information on aspects, such as minimum furnace dimensions for the suggested heat input and operating variables, such as excess air and FGR (if any). Provided with this data, the boiler designer can proceed with the furnace and boiler design.

NOTE Fuel oil and gas fired boiler furnaces typically operate under pressure. The typical operating pressure range is 1.25 kPa (ga) to 5 kPa (ga) (5 in. H_2O to 20 in. H_2O at 60 °F).

There are a few parameters of interest to the heat transfer engineers. The fuel input on HHV basis divided by the furnace volume gives the volumetric heat release rate in W/m^3 or Btu/(h-ft^3). This number indirectly gives an idea of the residence time of the fuel in the furnace and is generally considered important for difficult to burn solid fuels such as coal or fuels that require a longer residence time. However, for gaseous fuels or fuel oils, the volumetric heat release rate is not sufficient to design. High volumetric rates are likely in large shop assembled units, i.e. exceeding 68,000 kg/h (150,000 lb/h) steam, which have shipping limitations. A higher heat volumetric release rate (HVRR) than the calculated value described earlier does not mean a compromised design if the downstream components are properly designed and meet emissions requirements. Refer to Section 6 for more details.

Of further significance is the furnace area heat release rate W/m^2 [Btu/(h-ft^2)], obtained by dividing the heat input on HHV basis by the furnace effective projected radiant surface (EPRS) area, which is the projected area of the furnace walls, including the opening to the furnace exit. The area heat release rate is used to arrive at the FEGT. Refer to Section 6 for more details on the furnace area heat release rate. This gives an idea of the furnace absorption and thus the heat flux inside the furnace tubes. In large packaged boilers, the heat flux is in the range of 109,900 W/m^2 to 172,700 W/m^2 [35,000 Btu/(h-ft^2) to 55,000 Btu/(h-ft^2)]. This is well below the limit of 314,000 W/m^2 to 471,000 W/m^2 [100,000 Btu/(h-ft^2) to 150,000 Btu/(h-ft^2)] at which DNB conditions may be initiated in furnace circuits. Package boilers operating at steam pressures below 8 MPa (ga) [1200 psi (ga)] can handle even higher heat flux without initiating DNB conditions. In large field erected units operating at steam pressures exceeding 15 MPa (ga) [2200 psi (ga)], ribbed tubes are sometimes used to ensure the tubes are properly wetted by the steam water mixture. Hence, the ribbed tubes can handle a higher heat flux as compared to bare tubes. Typically, package boilers do not use them, unless the steam pressure and the heat flux are above normal values.

The furnace heat flux W/m^2 [Btu/(h-ft^2)] is the net heat absorbed by the furnace only, divided by the effective projected area. This furnace heat flux is different than traditional area heat release, and is what should be used to evaluate furnace design to ensure proper metal temperatures in tube walls and membrane fins.

- The purchaser shall specify ribbed or smooth tubes. Ribbed tubes can tolerate higher furnace heat flux than smooth tubes without DNB or steam blanketing of the waterwall tubes.

Today's boiler furnace offers a few improvements over the refractory lined furnaces of the past. Although some older designs utilized exposed refractory in the burner front wall, the majority of furnaces today are completely water cooled, with proven designs in operation for over the last two decades. The absence of refractory offers the following advantages:

a) no maintenance concerns with refractory;

b) faster start-up rates, as all furnace sections are operating at saturation temperature plus a few degrees and concerns about thermal stresses and refractory cracks are avoided;

c) completely water cooled membrane wall designs offer a leak proof enclosure for the flames and hence, no leakage of corrosive gases to the casing and consequent condensation and corrosion when fuels containing sulfur are fired;

d) with refractory lined boilers, if the furnace operates at pressure, there is the possibility of flue gases leaking between the casing and refractory and condensing outside the casing when the boiler is shut down or cooled, causing corrosion.

Since the region near the flame is also completely water cooled, NOx emissions are reduced, as the bulk of the NOx formation occurs at the burner end. Absence of refractory in the floor or front wall also reduces NOx emissions.

a) The furnace heat flux is also reduced for the given volume by 10 % to 12 %, as the front and rear walls are water cooled.

b) Membrane wall designs in low-pressure units {up to 6.9 MPa (ga) [1000 psi (ga)]} use 50 mm (2 in.) tubes on 100 mm (4 in.) spacing. Above these pressures, the membrane temperatures may increase, and hence, 64 mm (2.5 in.) tubes are used at 100 mm (4 in.) spacing, reducing the membrane width. Other variations are also used by different boiler suppliers, such as 50 mm (2 in.) tubes on 76 mm (3 in.) spacing, 76 mm (3 in.) tubes on 100 mm (4 in.) spacing, etc. The design depends on the boiler supplier's experience and manufacturing limitations.

Generally, the steam drum and mud drum are integral with the furnace in package boilers. However, large boilers may be designed with an elevated steam drum with external downcomers and risers. This increases the effective tube lengths and larger flue gas flows may be accommodated in the boiler.

a) Furnaces and gas passages shall be designed to prevent dead-ended or poorly ventilated pockets where combustibles might accumulate and cause an explosion upon ignition. Gas passes through the furnace shall be designed and arranged to prevent vibrations from vortex shedding and turbulence.

b) The dimensions and design of furnaces shall be such that complete combustion of fuels takes place within the furnace limits and without flame impingement on sidewalls, roofs, and front walls.

c) Based on the highest heating values of the fuels, the maximum heat release at 100 % MCR in a furnace of the water tube boiler type shall be designed according to Table 8. Credit for tile-covered floor tubes shall not exceed 10 % of the projected floor area.

d) Self-closing observation ports shall be provided. Ports shall be air-purged for cooling.

e) The number, size, and location of ports shall ensure the visibility of all burner tips, furnace rear walls, side walls, furnace exit areas, and furnace roofs.

f) Thermal expansion of furnace wall tubes should be considered to ensure vibration free operation.

5.5.4 Operation

Due to the amount of heat in the furnace, great care shall be taken to follow the operating instructions provided by the equipment manufacturer, especially during start-up. The boiler should be brought up to temperature and pressure at a slow and carefully controlled rate. While conditions vary, an accepted rate of steam drum water temperature rise is 44 °C to 56 °C (80 °F to 100 °F) per hour.

5.5.5 Maintenance

The majority of fire side maintenance in a furnace section will be from refractory repair. This section will see the highest temperature ranges and will have the most stress put upon it. Therefore, any expansion and contraction will result in cracking of, and damage to, refractory over time. Waterside maintenance will be similar to convection tube maintenance, described in 5.1.6, covering maintenance of superheater tubes.

5.5.6 Troubleshooting

See Table 7 for furnace troubleshooting options.

Table 7—Troubleshooting Furnaces

Trouble	Causes	Solutions
Tube blistering and failure.	Scale on inside of tubes. Direct flame impingement.	Chemically clean tubes. Check burner flame pattern.
Scale on inside of tubes.	Improper water chemistry. Departure from nucleate boiling.	Verify and, if necessary, change water treatment/water chemistry program. Confirm boiler circulation.
Refractory failures.	Normal service temperature change. Sudden temperature change.	Confirm and, if necessary, change operations.
Sudden overpressure.	Accumulation of combustibles. Induced draft fan trip.	Confirm and, if necessary, change operations.
Sudden underpressure.	Flame collapse.	Confirm and, if necessary, change operations.
Steam/water balance shows water loss.	Tube leak.	Shut down to investigate and repair.

6 Combustion, Burners, and Igniters

6.1 General Description

6.1.1 General

The combustion system for a boiler consists of the burners, boiler controls, and a combustion air delivery system. Boiler controls consist of the boiler control system, BFW control, CCS, and BMS. The combustion controls typically include fuel pressures and flow, combustion air flow, excess oxygen in the flue gas, fuel/air ratio, and FGR rate. The BMS includes flame monitoring, firebox pressure, air flow, and fuel pressure or flow.

This section describes boiler combustion and burner design. It also reviews features required to accommodate the fuels used in industrial boilers and the emissions produced. Further description of boiler controls and protective systems can be found in Section 7.

6.1.2 Combustion Design Parameters

Based on design fuel type at the maximum continuous rating (MCR), the boiler firebox should be designed such that the limits in Table 8 are not exceeded.

NOTE Table 8 may be used for gaseous and liquid fuels. Specialty or waste fuels may require different (likely lower) values. All heating values are on a HHV basis.

Table 8—Boiler Firebox Design Limits

Maximum Limits at MCR					
Fuel Fired	**Burner Type**	**Maximum Volumetric Heat Release**		**Maximum Firebox Radiant Heat Furnace Area Heat Release Rate [a]**	
		SI Units	**USC Units**	**SI Units**	**USC Units**
Gaseous fuels and liquid fuels lighter than 15° API (0.966 relative density)	Conventional	830,000 W/m^3	80,000 Btu/(h-ft^3)	480,000 W/m^2	150,000 Btu/(h-ft^2)
Liquid fuels (15° API and heavier)	Conventional	620,000 W/m^3	60,000 Btu/(h-ft^3)	480,000 W/m^2	150,000 Btu/(h-ft^2)
Gaseous fuels and liquid fuels lighter than 15° API (0.966 relative density)	Low NOx	620,000 W/m^3	60,000 Btu/(h-ft^3)	480,000 W/m^2	150,000 Btu/(h-ft^2)
Liquid fuels (15° API and heavier)	Low NOx [b]	410,000 W/m^3	40,000 Btu/(h-ft^3)	480,000 W/m^2	150,000 Btu/(h-ft^2)

[a] This is an average over the entire firebox absorbing heat transfer surface, the effective projected radiant surface. This value may be extended to 640,000 W/m^2 [200,000 Btu/(h-ft^2)] through careful evaluation, design, and high water quality.

[b] This is dependent on the type of low nitrogen oxide (NOx) burner considered and is a general guideline. Firebox volume and flux area are defined as volume and radiant surface area that are directly exposed to flame and where the predominant heat transfer mode is radiant, as opposed to convective. Additional information on low NOx burners can be found in 6.5 and E.1.

The furnace area heat release rate is defined as the heat input on a HHV basis divided by the furnace area. The volumetric heat release is defined as the heat input on a HHV basis divided by the furnace volume. The boiler heat flux is defined to be the furnace absorbed duty divided by the furnace surface area.

6.1.3 Combustion General Background

A boiler is divided into various sections where the heat from combustion is used to generate steam. The firebox contains the burner flame and is typically a tubular waterwall enclosed volume with sufficient space to prevent impingement of the burner flames on its walls, roof, and floor. Burners fire into the firebox and, depending on boiler configuration, are mounted on the firebox walls, corners, roof, or floor. It is essential for boiler reliability that all combustion occurs within the firebox. It may also be a refractory lined firebox, or a combination of waterwalls and refractory. Additional description of boiler components appears in Section 5.

Flame impingement (as defined by the American Boiler Manufacturers' Association) on the walls is not acceptable. Flame impingement on waterwall tubes will eventually cause a laydown of deposits; their source stems from impurities in the steam/water mixture, on the inside of the boiler tubes. The insulating effect of internal deposits and direct impingement of the flame on the tubes will cause the tubes to overheat and eventually fail.

Refineries and chemical plants typically install FD boiler designs. Typical FD firebox flue gas pressures range from 130 mm to 760 mm (5 in. to 30 in.), and up to 1020 mm (40 in.) for CO boilers, of water column above atmospheric pressure (positive pressure). Balanced draft boiler firebox flue gas pressures are near zero pressure and may be used if the fuel gas is delivered at very low pressures. Typical refinery and chemical plant boilers burn either "plant fuel gas," which is a byproduct of the refining process, natural gas, or liquid oil fuels. Additional information on boiler fuels can be found in 6.5.

Industrial boilers typically operate at excess oxygen levels in the range of 1.0 % to 4.0 % when operating at or near MCR. Excess oxygen describes the quantity of oxygen (in volume percent) remaining in the flue gas as it exits the boiler. The excess oxygen level requirement depends on boiler loading, air preheat, boiler design, fuel variability, load swings, fuel swings, and emission requirements. Low excess oxygen levels improve the efficiency of the boiler, but directionally reduce its ability to accommodate rapid load changes and fuel swings. Excess oxygen level is controlled by the boiler CCS, typically in a feedforward loop, that is, air leads on increasing load and fuel leads on decreasing load. This control, often referred to as “lead-lag control,” is described further in Section 7.

6.2 Igniters

6.2.1 Purpose

The main purpose of the igniter is to provide an ignition source to light-off the main burner flame. Each burner shall have its own individual dedicated igniter. Refinery and chemical plant boilers typically use interrupted igniters that employ a spark ignition device to ignite a small igniter gas or oil flame. That flame, in turn, is used to ignite the main burner flame. To verify the main flame is lit, the igniter is shut down at end of main fuel ignition safety time. Once the igniter is off, a flame detection device is used to verify the main flame is established. Extinguishing the igniter flame ensures that the BMS identifies only the main flame as being lit and that the flame detected is not the igniter flame. Additional information on flame detection can be found in Section 7.

The presence of one igniter per burner allows each burner to have its own ignition source. Cross lighting of the burners—the lighting of one burner from the adjacent burner—is prohibited. It is dangerous, as it requires a large amount of unburned fuel to leave the burner before being ignited, creating a potential explosion hazard.

The types of igniters used in industrial boilers are described in the section below. Some classes of igniters are designed to remain in service at all times, for use at low load conditions or other adverse operating conditions. These types of igniters require a heat release equal to or greater than the interrupted igniter described above.

In other fired equipment, the burner ignition source is often termed the “pilot.” In boilers this source is called an “igniter,” which may be in continuous service or intermittent service.

6.2.2 General Description

An igniter is a permanently installed device that supplies heat energy to ignite, or “light-off,” the main burner fuel. Along with summary properties, Table 10 summarizes these igniter classes as per NFPA 85 (2011), Sections 3.3.85 to 3.3.85.4.

Additional description of the igniter classes includes the following.

Class 1 igniters are continuous and designed to support burner stability at all times. Typically, Class 1 igniters are used to support combustion when the main burner fuel source may not be self-sustaining under all operating conditions.

Class 2 igniters can be intermittent (in-service part-time) or continuous under certain (adverse) operating conditions and are used to support combustion when the main burner fuel source may not self-sustaining. Additionally, Class 2 igniters can be used to keep the boiler warm, by providing a pilot hold, to facilitate a shorter start-up.

Class 3 igniters are interrupted and designed only to light-off the burner and not to support its stability.

Refinery and chemical plant boilers typically use Class 3 interrupted igniters. The igniter shall be sized sufficiently to light the burner at light-off conditions and does not necessarily scale with burner size.

6.2.3 Mechanical Details

Igniters may be raw gas or premixed type designs. Raw gas designs mix combustion air and fuel in the flame ignition zone of the burner, just before ignition. Premix igniter designs mix fuel and air upstream of the tip and before the flame ignition zone. Some igniters are a combination of premix and raw gas types.

A typical raw gas igniter consists of a gas nozzle, a fuel gas delivery pipe, and a removable electrode. In raw gas igniters, the gas nozzle is held in place by the gas supply pipe. The electrode tip is positioned near the base of the gas nozzle. The base of the gas nozzle has several small orifices that direct a small portion of the fuel gas into the mixing area or bluff body and toward the electrode tip. The electrode ignites the gas/air mixture at the base of the gas nozzle, creating a small anchoring flame. The anchoring flame then ignites the gas exiting the tip of the gas nozzle. The igniter air source supplies the combustion air for the anchoring flame and a portion of the combustion air for the main igniter flame. Fuel gas supply pressure is typically 7 kPa (ga) to 70 kPa (ga) [1 psi (ga) to 10 psi (ga)]. Examples of two raw gas igniters are shown in Figure 12 and Figure 13. Specifics of igniter design vary by manufacturer.

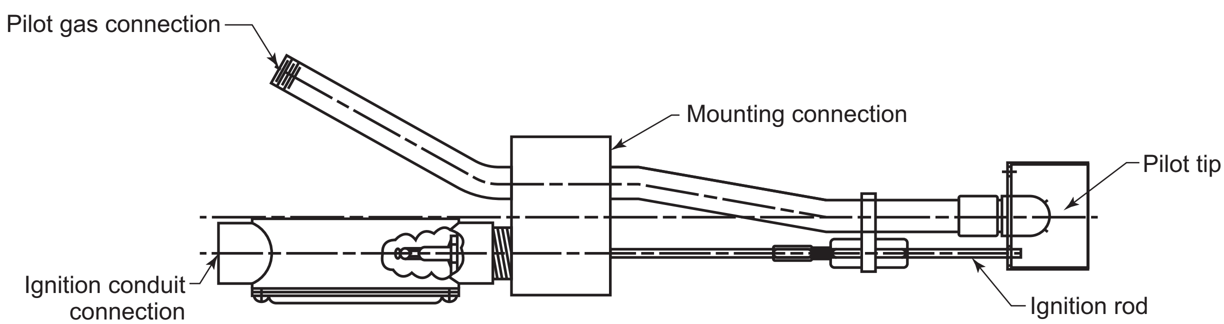


Figure 12—Raw Gas Igniter—First Type

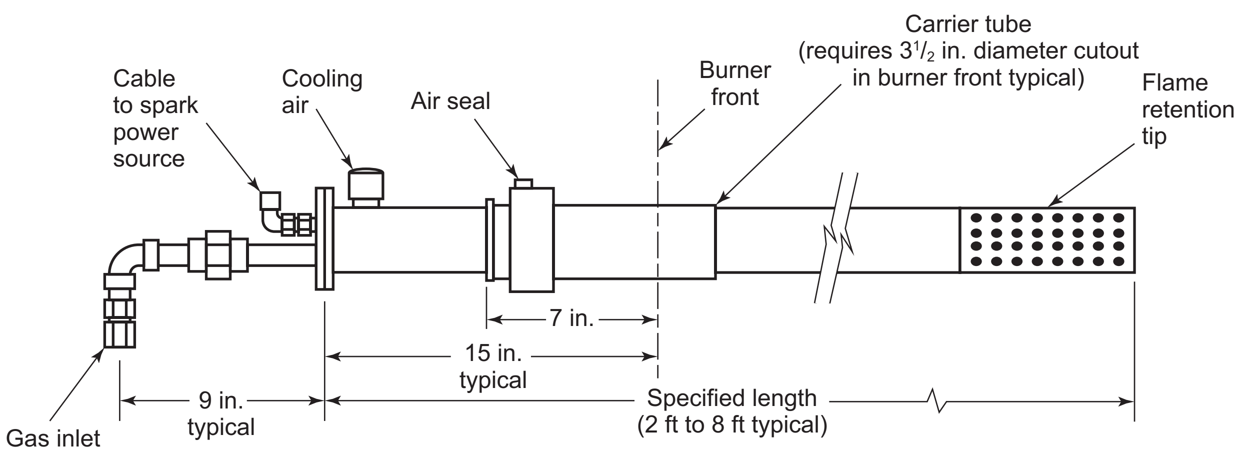


Figure 13—Raw Gas Igniter—Second Type

A typical premix igniter has the fuel gas and external air source proportioned through inlet orifices. The mixture passes through a riser pipe to the tip. A spark from an electrode ignites the gas/air mixture at the base of the gas tip and the flame extends through the tip to the burner throat. The external air source for the igniter is pressure regulated and provided either from an instrument air or utility air blower, or a blower local to the boiler. Gas and air supply pressure is normally around 70 kPa (ga) [10 psi (ga)], but can vary depending on the igniter design.

If a higher heat release flame is desired, the igniter is fitted with a second raw gas fuel tube along the side of the riser. This fuel is ignited by the flame exiting from the tip of the gas nozzle. Combustion air for the raw gas extended flame is supplemented by the main burner combustion air. An example of a premix igniter is shown in Figure 14. Specifics of igniter design vary by manufacturer.

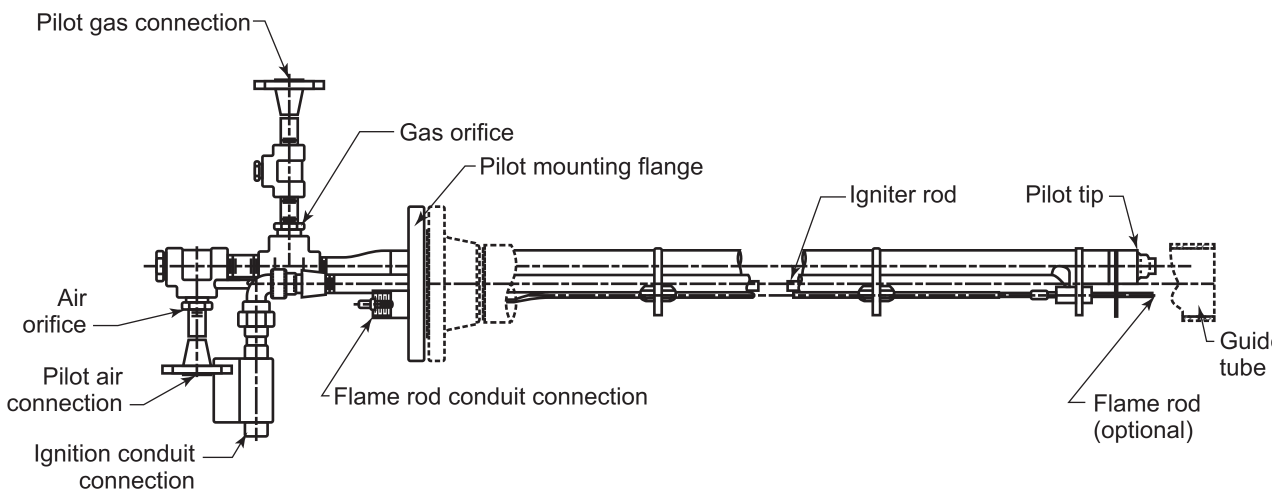


Figure 14—Premix Igniter

Gas and oil igniters may be fixed position or retractable design. Retractable igniters are inserted into their firing location when commanded by the BMS and then retracted after burner light-off has been completed. Retractable igniters are thus not exposed to radiant heat for extended periods. Fixed igniters are positioned within the burner throat to ignite the burner and require cooling air during boiler operation.

Raw gas and premixed igniters require an ignition system for initial light-off. Generally, these igniters require that an electrode capable of a capacitive high-energy or high-voltage discharge be located close to the igniter exit, near to where the flame will be located. Typical electrical requirements for high-voltage electrode ignition systems are 6000 V to 10,000 V and 20 mA, while high-energy igniters utilize a solid-state spark plug that produces a spark of generally of one joule, or greater, of energy, but at low voltage, typically less than 600 V.

The two electrode designs have some unique advantages. High-voltage electrodes have a longer history and offer a cost advantage. High-energy electrodes operate at lower voltage, allowing for the use of lower voltage wire between the exciter and spark device. The lower voltage is also not as susceptible to grounding through insulators and the system is less affected by carbon build up. The high energy of the igniter will ignite a wider range of air-fuel mixtures than will a traditional spark igniter.

The electrode that carries current to the pilot tip may be in the interior of the igniter or along the outside of the igniter. Electrode supports and/or penetrations into the igniter shall be constructed such that they electrically isolate the electrode from the igniter. In some cases the electrode in this location will serve the dual role of igniter and flame ionization detector.

6.2.4 Operation

Igniters shall be operated within a specific range of anchor flame air pressure relative to fuel pressure. This ensures that the initial stabilizing flame will light-off from the ignition spark. The remainder of the combustion air is supplied from the boiler fan operating at 25 % of MCR, or 25 % of full design air rate. The igniter is designed such that reliable ignition can be achieved without dropping combustion air below the minimum of 25 % of MCR. Some boiler designs result in more than 25 % MCR air flow to individual burners on light-off, a result of the use of burner air doors or higher light-off air rates. These boilers require pilots that achieve reliable ignition at the specified design light-off air rates.

Purge or sealing air may be required to continually cool the igniter, depending upon the design of the igniter, combustion air temperature, or FGR applications.

6.2.5 Maintenance

A periodic maintenance program should be implemented to ensure reliable operation of igniters. Maintenance of the igniter involves removal and disassembly and then cleaning the tip, checking the air passages for cleanliness, testing the transformer and ignition coil, checking the ignition cable insulation for cracks and wear, and inspecting/replacing the spark electrode and finally reassembling and installing the igniter.

The igniter assembly shall be removable from the boiler when the boiler is in operation. An air curtain in the housing for the igniter will enable the igniter to be pulled without allowing firebox gases or hot combustion air to escape.

6.2.6 Troubleshooting

A common problem with igniters is sighting them with the flame scanner. The flame scanner needs to be aimed with the igniter flame to attain a strong identification. This alignment requires time that is included in the start-up and commissioning schedule. Scanners are sighted (or aimed) by changing the sighting angle of the scanner by adjusting its swivel mount. If this is not successful the fuel and air pressure can be adjusted to produce a larger flame. The limits given by the manufacturer for fuel and air pressure shall not be exceeded.

If the igniter fails to light, the electronic sparking circuit shall be checked. Look for transformer or capacitor failure, a wiring short between the spark electrode and high energy voltage source, poor grounding of the circuits, or scanner sensitivity set incorrectly.

6.3 Burners

6.3.1 Purpose

The burners' function is to provide:

a) location for introduction of fuel and air at desired velocities and turbulence;

b) stable combustion (flame is steady with a well anchored root that is attached to the burner throat at all specified operating conditions);

c) well-shaped flame with no impingement on the surrounding walls of the firebox;

d) combustion byproducts, such as particulate, CO, NOx, and O_2, within specified parameters.

6.3.2 General Description

Boiler burners differ in many ways when compared to fired heater burners; however, API 535 provides guidelines that are sometimes applicable and valid for industrial boiler burners as well. API 535 provides detailed information on environmental considerations, combustion air, gas firing, liquid fuel firing, low NOx design, mechanical parameters, operation, maintenance, testing, and troubleshooting.

Boiler burners are typically an order of magnitude larger in heat release than fired heater burners. Individual fired heater burner heat release ranges from 0.7 MW to 20 MW (2.5 MBtu/h to 68 MBtu/h), while industrial boiler burners range from 7 MW to 120 MW (25 MBtu/h to 400 MBtu/h). Boiler burners typically use FD fans providing 130 mm to 300 mm (5 in. to 12 in.) water column (WC) full flow air pressure drop to produce the desired air-fuel mixing, flame shape, and turndown requirements.

Industrial boilers may have single or multiple burners (typically two to eight), depending on design requirements. Boiler burners are installed in openings through the boiler firebox wall, and in most cases, are fired horizontally. A description of boiler mechanical components can be found in Section 5.

Burner designs vary greatly and almost all include provisions to reduce NOx emissions. Various techniques are employed to do this, including:

a) staging of the combustion air to various portions of the combustion zone;

b) staging of the gaseous fuel to various portions of the combustion zone;

c) introduction of flue gas from the stack into the combustion air;

d) dilution of the incoming fuel (gaseous fuel only) with flue gas;

e) injection of water or steam into the combustion zone.

In addition, the burner and boiler can be designed to stage the combustion air to various portions of the combustion zone. The burner may operate at substoichiometric conditions, with the rest of the air for combustion being supplied via overfire air ports (also called NOx ports). Other combustion emissions controls are also available and further information on NOx emission reduction can be found in 6.3.7 and E.1.

As noted earlier in this section, industrial boilers typically operate at excess oxygen levels in the range of 1.0 % to 4.0 % when operating at or near their maximum continuous steam capacity, or MCR. Excess oxygen describes the quantity of oxygen (in volume percent) remaining in the flue gas as it exits the boiler. Another measure of the quantity of air supplied is percent excess air, where 100 % air is required for ideal stoichiometric combustion. The excess air (oxygen) is required to ensure complete combustion of the fuel and to provide a safe operating margin to allow for fuel and load variations. The amount of excess air required depends on boiler loading, air preheat, boiler design, fuel variability, load swings, fuel swings, and emission requirements. Low excess oxygen levels improve the efficiency of the boiler, but reduce its ability to accommodate rapid load changes and fuel composition swings. Excess air is typically supplied at between 5 % and 20 % over that required for stoichiometric combustion.

6.3.3 Mechanical Details

In general, boiler burners have:

a) fuel nozzles to direct and distribute gaseous or liquid fuel to the combustion zone (fuel nozzles are also known as canes, pokers, spuds, lances, or tips);

b) a throat section that delivers the combustion air into the combustion zone and creates the flame shape;

c) an air register or dampers to split total combustion air between the primary and secondary combustion zones (if an adjustable staged air design);

d) an air swirler or bluff body to create a recirculation zone for flame stabilization;

e) a device (e.g. a slide or a sleeve) that stops or minimizes flow of combustion air to the burner when it is out of service (for multi-burner applications);

f) a front plate that mounts the individual burner to the common burner windbox and holds the sight ports, scanner mounts, and various control handles for the combustion air;

g) a mounting arrangement that supports the burner in place within the firebox wall (refractory or water wall).

See Figure 15 for an example of a boiler burner.

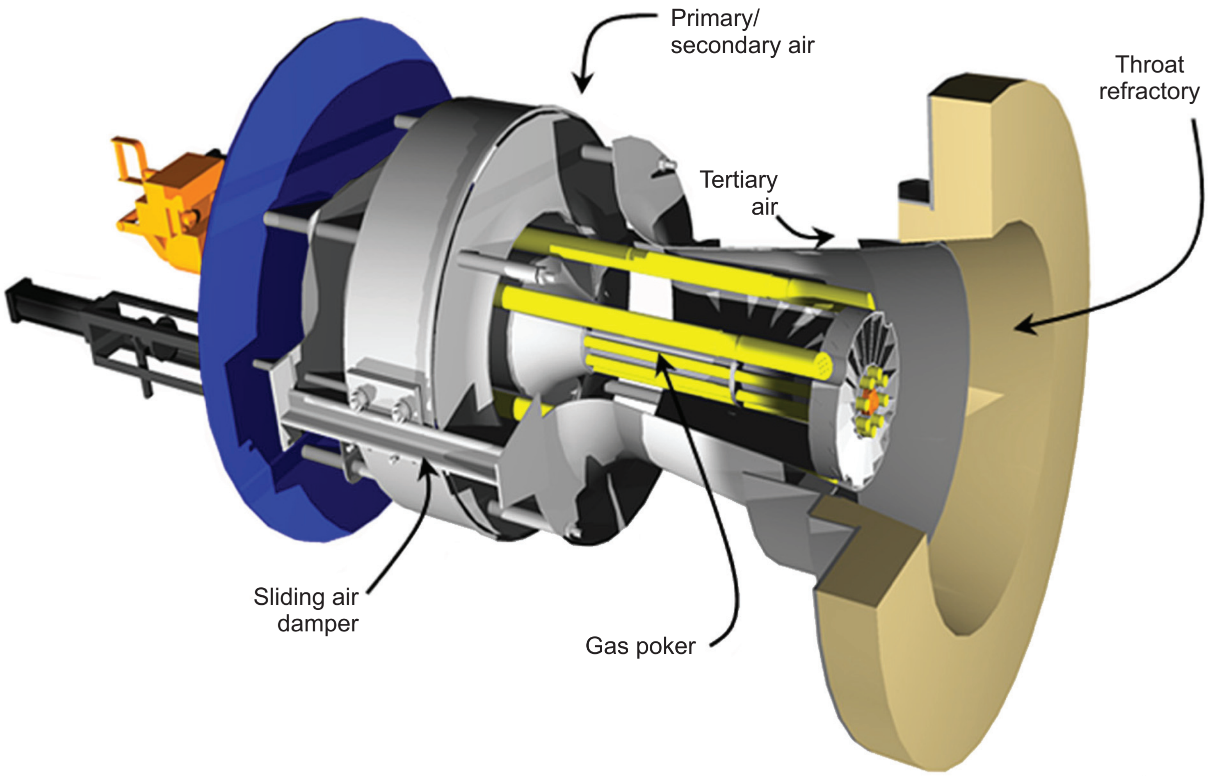


Figure 15—Boiler Burner

The nozzles generate a gas or liquid fuel spray pattern matching and aligned with the burner's combustion air distribution design to ensure proper air/fuel mixing. In some cases, fuel nozzles are designed to be removed from service for maintenance while the boiler is online. This can be achieved in multi-burner boilers by taking one burner out of service at a time.

The throat section of the burner shall be sized to deliver the combustion air to the primary combustion zone. It is designed with sufficient combustion air pressure drop to provide the air/fuel mixing required at the burner. Some burners employ a stationary air swirler or spinner downstream or within the throat. As the air flows across the stationary blades of the swirler, a tangential velocity component or spin is imparted to the air stream. Swirling the air flow enhances mixing of the combustion air and the fuel, which is usually introduced just downstream of the air swirler. The swirling air flow also anchors the flame inside the burner throat and reduces the flame length.

In many low NOx burner installations flue gas is mixed with the combustion air upstream of the burner windbox. The resulting mixture of flue gas (with its significantly reduced oxygen content) and incoming air will slow the combustion of the fuel and reduce peak flame temperatures. Flue gas can either be inducted into the inlet of the FD fan or blown into a mixing chamber of air and flue gas by a separate flue gas (recirculation) fan. Some low NOx burner designs employ flue gas addition directly into the gaseous fuel to lower the Btu content of the mixture and produce a lower flame temperature and consequently, lower NOx production. Further information on NOx emission reduction can be found in 6.3.7 and E.1.

Liquid fuels, such as fuel oil, are always fired from a separate oil gun that is independent of the gas firing burner nozzles. In a combination liquid/gas fired burner, the fuel oil gun is located in the center of the burner with the gaseous fuel firing around it. There are, in some cases, separate air registers to control the air to the oil or liquid flame, as well as to the gas flame. Heavier liquid fuels require a second fluid, such as steam or compressed air, to atomize the fuel and ensure good combustion. Typically, fuel oils are atomized at the nozzle tip using moderate pressure steam between 690 kPa (ga) and 1380 kPa (ga) [100 psi (ga) and 200 psi (ga)], at a rate of 0.03 kg steam to 0.3 kg steam/kg liquid fuel (0.03 lb steam to 0.3 lb steam/lb liquid fuel). Additional information on liquid fuels can be found in 6.4.

For boilers where burners can be taken out of service, a register or air slide (concentric cylinder) is used to block air flow to individual out of service burners. This register is required by NFPA 85 for multi-burner boiler installations where the burners can be taken out of service independent of each other. These devices are designed to allow some leakage (e.g. 10 % of burner air flow) to cool out of service burners and prevent overheating. When some burners are out of service, the registers allow the remaining in service burners to achieve proper combustion air flow to maintain a stable flame at LEA levels (or 2 % to 4 % excess O_2 in the flue gas).

6.3.4 Operation

Boiler flue gas oxygen content is selected as a function of boiler type and operating requirements. The flue gas oxygen target is selected based on boiler firebox geometry, number of burners, emission requirements, fuel type, control/instrumentation strategy, and economics. Industrial boiler burners are typically operated with 2 % to 4 % oxygen in the flue gas. Specific examples include base loaded field erected boilers at 1.5 % O_2, small package boilers at 2 % to 3 % O_2, and large package boilers with a single burner at 3 % to 4 % excess O_2. Emissions considerations may require operation at other oxygen levels; for example, boilers with high volumetric heat release may require higher excess O_2 to control CO production. In some cases, boilers can be operated at lower excess O_2 levels based upon a constant steam demand and stable fuel composition. All of these values are for operating points greater than 60 % of maximum steam production. Operation below this steam production will often require additional excess O_2 in the flue gas.

Combustion air is sometimes adjusted during burner tuning to the various zones of the burner to control flame shape and emissions performance.

Fuel gas nozzles are generally designed for 35 kPa (ga) to 210 kPa (ga) [5 psi (ga) to 30 psi (ga)] fuel pressure at 100 % of MCR (full load), but have a much lower pressure at turndown. The burner vendor will set the fuel nozzle drilling size and angle for the particular flame shape and emission requirements. Burner fuel pressure is changed to reduce or increase steam production as the steam demand on the boiler changes. Combustion air flow rate change leads the fuel quantity change as fuel pressure is increased and lags the fuel quantity change as the fuel pressure is decreased.

Fuel gas nozzles are sometimes adjusted or changed during initial commissioning to fine tune emissions and improve the flame shape. Depending on burner design, adjustments may not be possible. In some designs some or all of the following adjustments can be made:

a) gas tip alignment,

b) gas tip insertion distance,

c) staged air register positions,

d) excess oxygen level,

e) percent FGR,

f) bluff body or swirler position,

g) fuel distribution between tips.

Liquid fuel tips are sometimes adjusted or changed during initial commissioning for emission and flame shape control. Depending on burner design, adjustments may not be possible. In some designs some or all of the following adjustments can be made:

a) tip drilling pattern (number, size, angle);

b) tip alignment;

c) tip insertion distance;

d) staged air register positions;

e) excess oxygen level;

f) percent FGR;

g) difference in pressure between atomization fluid and liquid fuel.

6.3.5 Maintenance

Burner maintenance depends on design and may include oil and gas tip cleaning, stabilizer (air swirler or bluff body) repair, lubrication of the air slide mechanism, refractory throat repair, air register lubrication and adjustment, and general measurement checks for position and wear of the gas tips and drilling size verification. These activities are typically only practical while the boiler is out of service.

In many cases the only maintenance that can be performed while the boiler is in operation involves an individual burner that has been shut down and isolated. Gas tips can be removable. However, an air curtain type seal shall be in place to prevent windbox pressure from escaping through the hole from which the tip can be or has been removed. In some cases where the air in the windbox has been preheated or mixed with flue gas, this creates a hazardous atmosphere at the burner front, unless an air curtain or flapper is used against the windbox pressure. In an air curtain, a pressurized air source enters the tube that the gas tips pass. When the gas tips are removed, this air enters the gas tip tube and exits both the windbox side and the outside, effectively isolating the windbox from the outside. In some cases burners can be designed such that one gas injector can be isolated with a manual valve and removed for cleaning while the other gas injectors in the burner are still online and firing.

Oil guns are typically designed to be removed from the burner for maintenance and cleaning while the burner is still online, either firing on gas or firing on oil through the use of an auxiliary oil atomizer.

When the boiler is down, the burner should be inspected from inside the windbox if space permits and from inside the firebox of the boiler. Dimensional and position checks should be made at that time and compared against burner drawings supplied by the manufacturer.

6.3.6 Troubleshooting

Troubleshooting is usually done with the boiler and burners in operation. Therefore, sight ports shall be provided by the boiler manufacturer to enable the operators to observe the flame pattern of each burner. The sight ports can be located on the burner and the boiler wall. Sight ports are located on the burner to assist with igniter and burner condition monitoring, and shall be a minimum of 50 mm (2 in.) in diameter. Sight ports shall also be provided on the boiler end wall to allow observation of flame impingement on the side walls of the boiler. Additional sight ports shall be provided in the side walls to verify the length of the burner flame and to allow observation of impingement on the end wall. All wall mounted sight ports shall be at least 75 mm (3 in.) in diameter or 50 mm by 100 mm (2 in. by 4 in.).

Combustion vibration, or combustion instability, is sometimes a problem with boiler burners. Extensive studies have been done by boiler vendors relating gas tip velocity and combustion air flow relative to this problem. In most cases this can only be corrected by contacting the burner vendor or boiler consultant. Often this is tied to a particular operating point, and a short-term resolution is to avoid that operating point.

The flame from each burner in a multi-burner boiler shall look similar. There are various reasons that this may not be the case. If each burner is not receiving the same amount of air flow, there may be a problem in the design of the windbox that supplies air to all the burners. The windbox design may not be providing equal air flow to all of the burners. Cold flow or computational fluid dynamics (CFD) models are usually used to determine the need for, and placement of, internal baffles within the windbox to ensure equal air distribution to each burner. See 6.3.8 for more information on air distribution. Also, fuel pressure variation will occur on multi-elevation burner applications burning liquid fuel because of the difference in pressure caused by the vertical column of fuel to the upper burners.

- In addition, CFD or empirical correlations are being increasingly used to determine how well the burner flames will fit within the boiler. This should be completed during the boiler design phase and reviewed and approved by the boiler vendor, burner vendor, and the boiler owner.

It is important to monitor and detect flame impingement when the boiler is in operation. Firebox monitoring is best made after dark, when there is minimal interference from background light. Tubes experiencing flame impingement may change from a dark brownish to a reddish color when flame impingement is occurring. Flame impingement can sometimes be observed through properly located sight ports on the burner wall, side walls and rear wall. In new equipment sight ports shall be located to enable the viewer to see along the walls of the firebox. Infrared thermography (IR) can be used to locate boiler tube and wall hot spots and estimate temperatures. To allow IR scanning, special sight ports are required, or the use of purge air is required to allow the opening of sight ports while the boiler is in operation. The burners should be adjusted when flame impingement is detected.

Internal inspections shall also be completed during shutdowns. During these inspections, soot may be found on the boiler tube surfaces where flames have impinged, cooled, and left carbon deposits. Bulges may be found in the tubes where prolonged flame impingement has occurred.

6.3.7 Emissions Control Technologies

NOx reduction methods are divided between primary techniques, which seek to avoid the formation of NOx in flames, and secondary techniques, which are applied downstream of the combustion chambers to reduce NOx already formed. The former are termed combustion controls, and the latter are post-combustion controls. Depending on the required abatement rates, it is possible to combine primary and secondary techniques.

Burner emission reduction design techniques or combustion controls are highly successful at controlling NOx emissions. In all cases, modifications that reduce emissions increase the design and operational complexity of the burner. The most typical approach today is to combine a variety of NOx control techniques to achieve the target NOx level cost effectively, and several of the techniques are reviewed below. As some NOx production is a strong function of temperature, some techniques reduce peak flame temperature and the resulting NOx level. Additional information can be found in Annex E.

One burner emission reduction technology includes air staging, the addition of air passages directing combustion air to various zones of the burner and flame. Primary, secondary, and tertiary air zone passages are common.

Fuel staging involves releasing fuel into the burner combustion zone at different locations. As an example, one burner design contains a center gun with gas jets drilled at different fuel release angles, which is surrounded by an air spinner, then there is an intermediate fuel release zone fed by a different set of tips, and finally an outer release zone with a third set of tips. The net effect is to stage the release of the fuel along the axis of the burner. Staging the fuel delays combustion and therefore reduces the peak flame temperature reached.

FGR reduces combustion temperatures by mixing flue gas into the incoming burner combustion air prior to entry of the air into the windbox. This recirculated flue gas can make up to 40 % of the incoming air to the burner and flame. In some cases this is done at the inlet to the FD fan. In this case a duct is run from the boiler stack directly to the suction side of the FD fan. This duct may have a damper to control the amount of gas being recirculated. In other cases a dedicated recirculation fan takes suction from the stack and discharges to a mixing chamber located after the FD fan.

Typically, a boiler burner will employ combustion air staging, fuel zone staging, or FGR to reduce NOx generation. When firing gaseous fuel, NOx levels fall into three general (although approximate) categories: conventional (>100 ppmvd), low NOx (<100 ppmvd and >30 ppmvd), and ultralow NOx (<30 ppmvd). This can also be expressed as conventional units: 0.12 lb NOx/MBtu, low NOx (<0.12 and >0.035 lb NOx/MBtu), and ultralow NOx (<0.035 lb NOx/MBtu). Values in ppmv units are corrected to 3 % O_2 dry.

NOTE The ppmvd numerical values are approximations. Specific environmental authorities may use fuel HHV or lower heating value (LHV) values as emission basis; confirm which heating value type is applicable to the specific boiler location.

When firing liquid fuels, the NOx produced is greatly dependent on the nitrogen content of the fuel being fired. If the fuel contains compounds with embedded nitrogen, NOx is one of the products of combustion.

Another type of FGR includes dilution of the fuel by adding flue gas and/or steam. This is a complex design that involves fuel and flue gas manifolds with injector nozzles that direct fuel into a flue gas inspiriting tube. Steam can be used as an eductor to assist in bringing the flue gas into the fuel gas manifold at the burner. NOx results as low as 20 ppmvd has been achieved with this technique in conjunction with air and fuel staging. Direct injection of steam into the combustion zone is another technique for NOx reduction.

As mentioned previously, in some cases burners are designed to run under substoichiometric conditions (fuel rich), with the remainder of the air required for complete combustion/burnout being injected into the firebox separately via ports specifically located to optimize burn-out. The number, size, and location of these ports are typically determined through modeling of the firebox. Location of the ports is critical to achieve complete combustion.

Most NOx reduction techniques tend to slow or delay combustion and lengthen the flame. The impact on flame shape shall be analyzed by the burner vendor and boiler manufacturer before employing these techniques.

One of the factors influencing NOx formation in a boiler is the excess air levels. For non-premix burners, high excess air levels (>10 %) may result in increased NOx formation because the excess nitrogen and oxygen in the combustion air entering the flame will combine to form thermal NOx. LEA firing involves limiting the amount of excess air that is entering the combustion process in order to limit the amount of extra oxygen that enters the flame.

A more detailed discussion on NOx control can be found in Annex E.

Another emission from industrial boilers is CO. CO is a product of incomplete combustion, as complete combustion results in CO_2. Directionally complete combustion will occur if there is sufficient oxygen present and temperatures are high enough. Combustion kinetics requires excess oxygen (air) over the stoichiometric balance to ensure low levels of CO production. The most efficient boiler operation, in terms of fuel usage and parasitic power losses, occurs at a CO emission rate of 400 ppmvd. At this value, overall fuel and energy usage is optimized and has thus been set as the maximum CO emission rate for facilities regulated by the U.S. EPA. Operating facilities typically run below 200 ppmvd CO to allow operating flexibility and for safety consideration.

6.3.8 Combustion Air Flow Distribution

Boiler emissions performance and burner excess air level are greatly influenced by the combustion air distribution to and around the burners. When multiple burners are provided in a boiler, careful consideration shall be given to create equal air flow to each burner. Typically, the combustion air will be supplied to a common windbox with a single inlet. Likewise, peripheral distribution and swirl of the air entering each burner can have a large influence on flame shape and stability. This is especially true in single burner applications. Swirl entering the burners has been linked to burner vibration in many cases. Placement of solid or perforated baffles to distribute the air to and around each burner equally is usually determined by a cold flow or CFD analysis of air flow in the windbox. Experience has found most problems are avoided if:

a) modeled mass flow of air to each burner within ±2 % of average, ±5 % of average once constructed;

b) peripheral distribution around each burner within +10 % of burner average;

c) no swirl entering the burner (swirl is created by the burner itself; e.g. air doors, swirler, etc.).

6.3.9 Flue Gas Recirculation—Combustion Air Temperatures and Acid Dew Point

6.3.9.1 General

Burners operating in the conditions listed below may be subject to issues with acid dew point corrosion. Issues arise if the air entering the burner drops below the dew point and contains compounds that result in corrosion due to the acidity of the condensed water. Installations where this may occur include:

a) boilers using high percentages of FGR,

b) boilers using combustion air at very high humidity (bearing a large amount of water from either weather conditions and/or local high humidity conditions),

c) boilers operating in locations where the combustion air temperature varies greatly,

d) boilers firing sulfur-bearing fuels (e.g. #6 oil and some waste fuels).

6.3.9.2 Flue Gas Recirculation

Flue gas generally contains a large amount of water vapor coming from the combustion of hydrogen contained in the fuel. This water vapor combines with the water vapor naturally present in the fresh combustion air. Special care shall be taken when designing systems handling FGR and/or FGR with combustion air to avoid condensing or freezing conditions. This can result in corrosion of air ducts or air control devices. Corrosion is much more severe when the fuels contain sulfur; this is described in more detail in the following sections.

6.3.9.3 Combustion Air Temperatures

Ambient temperature changes will affect the total volume of air entering the burner. In most cases, an overall temperature variation of 28 °C (50 °F) (maximum temperature minus minimum temperature) or less will not significantly affect the burner performance. Where variations are greater than 28 °C (50 °F), special attention shall be given to:

a) combustion air fan and flow control device sizing;

b) combustion air flow measurement, purge and minimum air flow signals;

c) CCS's ability to detect and correct combustion air flow deviations;

d) relative humidity—for a given relative humidity ratio, water vapor content of gases increases with temperature.

6.3.9.4 Sulfuric Acid Dew Point

When firing sulfur-bearing fuels, determining the sulfuric acid dew point is critical to limiting dew point corrosion. It will be necessary to limit the boiler's minimum flue gas exit temperature, as well as ensuring the minimum temperature of the combustion air. It is a requirement to keep the FGR/fresh air stream above the sulfuric acid dew point. This is more critical in induced FGR systems where the FGR and induced air are mixed upstream of the FD fan. Typically, when designing burner systems incorporating high sulfur fuels (such as heavy oils), forced FGR systems are preferred over induced designs to allow NOx control and prevent corrosion issues in the FD fan. It is important to also note a portion of sulfur dioxide (SO_2) in the flue gas is converted into sulfur trioxide (SO_3) and will react with water vapor and convert to sulfuric acid (H_2SO_4). Therefore, sulfuric acid dew point also depends on the SO_3 conversion rate.

6.4 CO Boilers

6.4.1 General

This section includes the combustion detail specifics for CO boilers and supplements the general information included in other sections. Mechanical information on CO boilers has been included in 4.3.8.

6.4.2 General Description and CO Fuel

Significant low-pressure gas volumes containing CO are available in refineries as a byproduct of the catalyst regeneration process in FCC and residue cracking (RCC) units. These gases, called "regenerator off gas" or "CO gas," may also contain large quantities of catalyst fines.

This CO gas is utilized for steam production for three reasons:

a) to recover the sensible heat available, usually leaving the process unit at temperatures higher than 540 °C (1000 °F);

b) to convert CO to CO_2 before discharging the flue gases to atmosphere; and

c) to reduce the exhaust gas temperature prior to catalyst fine recovery devices.

Depending upon the regeneration process, two types of heat recovery are available: fired boiler and unfired waste heat boiler. A fired boiler is common when carbon deposits on catalyst are removed with LEA. The flue gases, rich in CO, need to be converted to carbon dioxide before its discharge to atmosphere. Fired boilers are reviewed below; additional information on unfired boilers can be found in API 534.

CO boiler design shall take into consideration the three reasons mentioned above, i.e. recover the heat available, convert the CO to CO_2 and cooling for fines recovery. This equipment serves not only as a boiler, but also as an incinerator where residence time at high temperature is the key factor for proper CO oxidation.

For the fired boiler, the following two solutions are available.

a) The typical design of natural circulation water-wall boilers, where the radiant section is properly sized to provide the required residence time for CO destruction.

b) The adiabatic/refractory type where oxidation of CO gas takes place in a combustor and the heat is fully recovered in a convection section. The adiabatic type is utilized particularly when flexible steam production and high turndown capacity are desired.

In general, the requirements for the design of CO boilers are similar to that of boilers that utilize other gaseous fuels. However, the design has to take into account some special features required for CO combustion and the special characteristics of combustion gases. The following differences shall be considered in CO boiler design.

a) Significant CO gas volumes are burned to obtain heat input to the boiler. This means large fuel gas valves, fuel skid, and burners, with a possible special design for the boiler furnace front wall.

b) The regenerator off gas (CO gas) contains approximately 95 % inerts and 5 % combustibles. As a result, the flue gas flow is much larger than the flow in a natural gas fired boiler with the same heat capacity. The CO gas requires the addition of 0.1 to 0.3 volume of air per volume of CO gas for stoichiometric combustion. The CO boiler design shall account for the higher volumetric flow of the CO gas fuel.

c) Due to high percentage of inert compounds in CO gas, supplemental fuel is needed in order to ensure a stable flame, desirable flame temperature and to reach complete burnout of CO.

d) Online cleaning capabilities, e.g. sootblowers, for boiler surfaces should be installed. Special attention should be given to superheater and evaporator sections.

e) Access for inspection and maintenance should be provided. Such access should be located in superheater and evaporator sections.

In summary, CO boilers are bigger than gaseous- and liquid-fueled boilers of the same output.

6.4.3 Mechanical Design Details

6.4.3.1 General

This section describes the minimum requirements in the design process of a CO boiler, taking into account the special considerations for this fuel.

Boilers shall be of a proven design, with an experience base of similar equipment working under similar conditions without major problems. Unproven, prototype equipment is not acceptable.

Design parameters shall determine whether the boiler is a forced-draft or balanced-draft configuration, and forced or natural circulation type. A non-steaming economizer design under all load and fuels operation is recommended.

The entire steam-water circuit is to be fully drainable. If this requirement cannot be met, the boiler designer should explain and demonstrate operability of the non-drainable design.

Space and access shall be provided for inspection, cleaning, maintenance, and repairs.

Due to the unusual fuel, special care shall be taken in boiler sizing and auxiliary equipment selection (mainly forced/inducted fans, fuel valves skid and burner).

All auxiliary equipment components are larger than conventional boilers for a given heat release due to the large volumes of CO gas being consumed.

The design of boilers located outdoors shall be suitable for continuous operation at the ambient design conditions. All external surfaces shall be self-draining and protected against corrosion.

Boilers shall be designed to operate continuously in automatic mode. Natural circulation through the complete operational range has to be considered for natural circulation systems, and provision for emergency pumping power shall be considered for forced circulation systems.

6.4.3.2 Combustion Design Details

The firebox extends from the burner wall to the first row of screen tubes or to the first row of superheater tubes for boilers without screen tubes.

Firebox and the whole gas pass shall be designed to prevent dead-end or poorly ventilated pockets where combustibles might accumulate. The design shall prevent combustion vibration, undesired turbulence, and flame impingements on the firebox walls.

The maximum firebox volumetric liberation (heat release) should be 310 kW/m^3 [30,000 Btu/(h-ft^3)], at 100 % MCR. For this calculation, the fuel HHV and the firebox volume up to the screen or first superheater row shall be used. Finally, the design shall prevent erosion that can easily occur due to particulate material in the stream.

The auto-ignition temperature of CO is 607 °C (1120 °F) (NFPA HAZ01 and EN 60079-20-1), and the CO-to-CO_2 conversion time is a function of the gas temperature beyond this value. At 815 °C (1500 °F) more than 90 % of CO is converted to CO_2 within 0.04 s [provided that the oxygen (O_2) content is within the flammability limits]. Conversion at higher levels takes significantly longer. It is essential for the combustion of CO gas that the gas temperature is higher than 815 °C (1500 °F) and that sufficient O_2 is available. The degree of conversion (or percent conversion) is used to obtain a minimum firebox temperature and residence time. Some installations require a minimum temperature above 900 °C (1650 °F) for duration of 1.5 s. Other installations require a temperature high enough such that the conversion time is very short and the specification of residence time is not required.

The high gas temperatures required for CO combustion are reached by using a supplementary fuel (fuel gas or fuel oil). For sufficient O_2 an excess of combustion air is used. The O_2 content in the flue gas at the firebox outlet has to be higher than 2.0 volume %, dry.

- The oxygen content in the flue gas shall be specified by the purchaser.

Maximum gas velocity in the boiler shall be limited to avoid tube vibration issues in the boiler.

Mixing of CO gas and combustion air is difficult because of the large volumetric flow of CO gas and the temperature difference between the CO gas and the combustion air. To obtain the required mixing between these streams, the design of a CO burner differs from a conventional burner. The CO gas and combustion air may not be introduced through the same burner, but instead are split into several streams for CO ports and air ports. In general, the combustion air is split into primary air needed for the supplementary fuel, and secondary air for the CO gas and required excess air. The supply of CO gas has to be such that it goes through a hot zone together with the air. For better mixing, the large volumetric flow is split into a (large) number of small portions. The location of the CO gas supply can be upstream, downstream, or parallel to the supplementary burners. Burner suppliers have developed different solutions for burning CO gas.

- The allowable CO concentration in the flue gas shall be specified by the purchaser. A typical maximum CO concentration specification may be 50 ppmvd, or 63 mg/Nm^3, at 3 volume % O_2, dry in the flue gas.

Self-closing observation burner flame ports shall be provided. The number, size, and location of these ports should be determined by boiler designer, ensuring complete visibility of burners and all firebox walls (front, rear, roof, and floor).

Similar to conventional boilers, FGR may be required to meet emissions specifications. Combustion gases are taken from the duct between the economizer and the stack and induced using the FD fan. If the CO fuel pressure is not high enough, an ID fan is required and located before the stack.

6.4.4 Maintenance

During outages the burner throat refractory should be inspected and maintained, which is critical in conditioning the flame shape. The burner shall also be carefully inspected and damages repaired, and all gates should be checked to confirm they operate freely.

6.4.5 Troubleshooting

Troubleshooting CO boilers is similar to conventional boilers. Noise and vibration can be a more frequent problem due to the high combustion gas flow in the boiler. During operation vibration magnitude and frequency can be measured with appropriate placement of accelerometers. Analysis of information can provide insight into modification options. During turnarounds vibration problems will show up as tube fretting adjacent to spacers, baffles, or stiffeners. During operation the only way to combat vibration is to change the gas velocity through the tube bank. Mechanical modifications to combat vibration may include the addition of stiffeners or baffles.

6.5 Fuels Fired in Industrial Boilers

6.5.1 General

As described in 4.4, the primary fuels fired in most refinery and chemical plant steam boilers were historically No. 6 fuel oil, commonly called "Bunker C," natural gas, and plant byproduct gases, as these fuels were commonly available. Beginning in 1970 emissions regulations began and in some areas NOx reductions became mandatory. The first trend in the industry was to convert the oil-fired boilers to gas, as No. 6 fuel oil contains fuel bound nitrogen. When burned, a portion of the fuel-bound nitrogen converts to NOx; that fuel-bound (or fuel sourced) NOx can exceed the NOx generated from the thermal effects alone. Natural gas fuel has often replaced No. 6 fuel oil for its economic, environmental, and technological advantages. Section 6.5 describes the common fuels, both gas and liquids, used in refineries and chemical plants. Solid fuels are not reviewed, as their use in these facilities is rare.

6.5.2 Gaseous Fuel

6.5.2.1 Gaseous Fuel Descriptions

The following gaseous fuels are fired in refinery and chemical plant boilers. Table 9 provides the typical composition and characteristics of each of these gaseous fuels, except landfill gas.

a) Natural gas—is the most abundant and the primary gaseous fuel fired in industrial package boilers. It is readily available and a large distribution network exists in many countries. Natural gas varies in HHV from 35.7 MJ/m^3 to 43.3 MJ/m^3 (950 Btu/SCF to 1150 Btu/SCF) (HHV) due to variance in composition.

b) Propane—can be shipped and stored and is often used as a backup fuel when natural gas is not readily available. Propane should be heated to 65 °C (150 °F) to avoid condensation and the presence of liquid droplets in the fuel stream. The composition of typical commercial grade propane is given in Table 9.

c) Refinery/plant fuel gas—is a gas produced internally within the plant facility and is the byproduct of various chemical processes. The fuel is made up of various vent streams typically consisting of methane, hydrogen, ethane, propane, butane, ethylene, propylene, and butylenes all combined in a common header. As the composition varies, the heating value varies, and ranges from 26.3 MJ/m^3 to 52.6 MJ/m^3 (700 Btu/SCF to 1400 Btu/SCF) (HHV). Refinery fuel gas, depending on the hydrogen content, generates more thermal NOx than natural gas. The higher the hydrogen content, the higher the NOx due to the increased flame temperatures when burned. Given the variability in composition, the plant gas characteristics shall be supplied to burner and boiler designers. The burner manufacturer will optimize the burner design for heat release, stability, flame characteristics, maintenance and emissions over the fuel composition range expected. Depending upon the composition, the plant fuel may be fired at ambient temperatures or shall be heated as high as 79 °C (175 °F) to keep components from condensing. Typical plant fuel gas is distributed between 210 kPa (ga) to 630 kPa (ga) [30 psi (ga) to 90 psi (ga)]. It is supplied to boiler burners at a maximum pressure between 210 kPa (ga) to 350 kPa (ga) [30 psi (ga) to 50 psi (ga)]. Refinery fuel gases with heavy hydrocarbons (higher molecular weights) may also require "knock-out pots" upstream of the burners. These pots allow the liquid droplets to drop out of the fuel stream. The removal of the condensate is necessary to prevent liquids from coking and plugging the gas ports in the high temperature zones of the burner. Coalescers may also be installed upstream of the burners to remove condensate in the fuel. Large refineries and petrochemical plants may use plant fuel gas or off-gases supplemented by natural gas, LPG, or liquid fuel due to availability and economics.

d) Landfill gas—is produced from decomposing garbage. The landfill gas is collected using wells, either active or passive, and is cooled to 4 °C (40 °F) to remove moisture and then compressed before being sent down a pipeline to a boiler. Landfill gas is economical and a Low NOx fuel. Impurities can result in corrosion problems when the fuel is burned.

Table 9—Typical Gas Fuel Composition and Properties (Examples)

Constituent	Natural Gas (volume %)	Refinery Fuel Gas High H_2 (volume %)	Refinery Fuel Gas Low H_2 (volume %)	Propane Fuel Gas (volume %)	CO Gas, e.g. FCCU (volume %)
Methane (CH_4)	92	20.1	31.5		
Ethane (C_2H_6)	3	5.0	13.2	2.2	
Propane (C_3H_8)	2	5.9		97.3	
Butane (C_4H_{10})		6.7	0.1	0.5	
Pentane (C_5H_{12})		0.06			
Hexane (C_6H_{14})		1.1			
Carbon dioxide (CO_2)			2.1		14.4
Oxygen (O_2)					0.2
Nitrogen (N_2)	3	5.0	8.3		68
Carbon monoxide (CO)			1.1		7
Hydrogen (H_2)		52.6	28.0		
Ethylene (C_2H_4)		1.6	14.1		
Propylene (C_3H_6)		2.0	1.3		
Butylene (C_4H_8)			0.30		
Sulfur dioxide (SO_2)					0.4
Water vapor (H_2O)					10
HHV (kJ/kg)	51,540	52,850	45,310	50,400	690
HHV (Btu/lb)	22,160	22,720	19,480	21,670	298
HHV (kJ/m^3)	38,480	35,570	34,380	92,990	860
HHV (Btu/scf)	1030	956	924	2500	23
LHV (kJ/m^3)	34,640	32,000	30,960	86,180	860
LHV (Btu/scf)	931	860	832	2316	23
Fuel temperature (°C)	16	66	66	66	621
Fuel temperature (°F)	60	150	150	150	1150
Molecular weight	17.6	16.0	18.0	44.1	29.5
Specific gravity	0.60	0.55	0.62	1.5	1.0
Wobbe index	1340	1290	1170	2030	–

e) CO gas—huge quantities of low-pressure, low heating value flue gases containing CO are produced in refineries as a byproduct of the catalyst regeneration process in FCCUs and RCCUs. CO gas also contains particulates, catalyst fines, NH_3, and NOx. Further details on the use of this fuel are contained in 6.4.

6.5.2.2 Gaseous Fuel Firing Characteristics

The most important firing property of a fuel gas is the Wobbe index. The Wobbe index is calculated by dividing the HHV, expressed in MJ/m^3 (Btu/ft^3) by the square root of the gas's specific gravity (SG) relative to air at standard conditions. This property is an indication of the heat available from a fuel at a given supply pressure.

The second most important property is the HHV. Adiabatic flame temperature and flammability limits need to be assessed to determine if self-sustained combustion is feasible for low heating value fuels containing substantial inert components.

The third most important aspect of firing a gaseous fuel is keeping condensing liquids out of the fuel stream. Knock-out pots, disengaging drums, coalescers, and heat tracing/insulated fuel lines are four means to eliminate liquids in the gas stream.

6.5.3 Liquid Fuel

6.5.3.1 General

Liquid fuel firing is more difficult than firing gaseous fuels. Liquid fuel shall be atomized to a very fine mist, somewhat like a heavy fog, before the liquid will burn completely. This section describes the typical liquid fuels used in industrial boilers and their critical characteristics.

6.5.3.2 Liquid Fuel Firing Characteristics

There are many factors that affect the firing performance of liquid fuels. The major factors include viscosity, heating value, SG, constituents in the fuel, and the boiling points of each constituent.

Heavy fuel oils, asphalt, asphaltenes, pyrolysis fuel oil, etc. can be successfully burned, but they require careful attention to detail and more maintenance in the field. Some fuels shall be heated to achieve a viscosity of 200 SSU or less, but not too high that some of the light ends are flashed off causing unstable firing.

Liquid fuel firing may result in stack flue gas opacity excursions with visible smoke. During these events there may be sufficient oxygen and low CO levels, below 100 ppmvd. This is typical of a fuel with heavy fractions and irregular droplet size. The large droplets form straight carbon particles and cause smoke without generating CO, which otherwise would be viewed as an indication of incomplete combustion. Smoke is an indication that atomization quality is poor and also indicates that the volatile light ends are flashing, causing irregular diameter droplets of heavy end material.

The viscosity for most liquid fuels is available in the references. Viscosity is temperature dependent, with lower viscosity at higher temperatures. Viscosity plots are used when designing equipment for liquid fuels. Viscosity is normally given the units of SSU (Saybolt seconds universal) or in Centistokes. For example, a typical No. 6 fuel oil at 71 °C (160 °F) has a viscosity of 175 SSU, or 37.5 Centistokes. A specific No. 2 fuel oil at 21 °C (70 °F) has a viscosity of 36 SSU, or 3.0 Centistokes. As a general rule, No. 6 fuel oil shall have a viscosity of less than 10,000 SSU in order to pump the liquid. For comparison, an average grade of molasses at 54 °C (130 °F) would have a viscosity of 40,000 SSU or 8880 Centistokes.

Vaporization of the liquid fuel droplets is required before the liquid will burn, and complete combustion is strongly dependent on the surface area to volume ratio of the drops. Increasing the droplet surface area per volume and reducing the droplet size increases the rate of fuel vaporization and improves combustion. It has been demonstrated that the lifespan of a fuel droplet undergoing combustion is directly proportional to the square of the droplet diameter. Therefore, liquid fuel combustion is optimized by minimizing the average droplet size of the fuel spray.

Poor liquid atomization results in larger droplet sizes and can result in higher particulate production. Smaller droplet sizes result in an increased flame temperature and increased intensity of combustion, which may increase NOx emissions. Reducing droplet size to reduce particulate emissions may adversely impact NOx emissions.

The average diameter most commonly utilized to characterize liquid fuel sprays is the Sauter mean diameter (SMD). The specific surface of a droplet is defined as its surface area divided by its volume. The SMD is defined as the diameter of a droplet whose specific surface area is the same as that for the total number of droplets in the spray. Directionally, improved combustion characteristics are achieved by introducing liquid fuels at smaller SMDs.

Atomization is the process whereby a volume of liquid is converted into a multiplicity of small drops. Its principal aim is to produce a high ratio of surface area in the liquid phase, resulting in very high evaporation rates. Heavy-oil fired burners use pressure and steam atomization in combination. The function of the atomizer is to attenuate the fuel exiting the fuel nozzles into fine jets from which ligaments and ultimately drops will be produced. The distribution of the resulting drops is a controlled spray pattern. The atomizing steam shall be dry and shall be either superheated or saturated steam from lines that are well trapped and insulated.

The spray characteristics of importance to combustion performance include mean drop size, drop-size distribution, burner tip hole pattern, cone angle, and penetration. Special importance is attached to mean drop size, drop-size distribution, and burner tip hole pattern because they are solely dependent on the atomizer design. Cone angle and penetration are governed partly by the atomizer design and partly by the aerodynamics influence of the burner air.

If visible particles exit the boiler stack, it is termed “opacity.” This is measured in percentage opacity or Ringelmann number, and can be the result of unburned coke particles or inorganic particulates. Zero opacity is smokeless combustion. For smokeless combustion the air supply shall be well mixed with the fuel spray. The atomizer shall provide uniform and homogeneous fine jets of fuel and steam mixed to promote disintegration into fine droplets of fuel. In order for the atomizer to provide consistent spray, the fuel supplied to the atomizer shall always have the same properties. Whenever the fuel type is changed, the system shall be changed in order to provide acceptable results because fuel preheat, fuel pressure, and fuel properties will affect the flame and emissions produced. Blended fuel, with both light and heavy fractions, are difficult to burn clean because flashing at the tip occurs, leaving heavy irregular droplets of aromatics and olefins that are difficult to burn, even with fine regular droplets.

6.5.3.3 Liquid Fuel—Fuel Oil

Fuel oils are identified by grades; typically No. 1, No. 2, No. 4, No. 5, and No. 6. No. 1 and No. 2 are classified as distillates, and No. 4, No. 5, and No. 6 are residual oils. No. 4 can be a distillate or a mixture of refinery products. All fuel oils are classified according to their physical characteristics by the specification set forth in ASTM D396. Table 10 contains a summary of fuel oil properties.

Table 10—Typical Analyses and Properties of Fuel Oils (Examples)

Grade	No. 1	No. 2	No. 4	No. 5	No. 6
Type	Kerosene	Distillate	V. Light Residual	Light Residual	Residual
Color	Light	Amber	Black	Black	Black
API Gravity @ 16 °C (60 °F)	40	32	21	17	12
Specific Gravity @ 16 °C (60 °F)	0.8251	0.8654	0.9279	0.9529	0.9861
Viscosity, cP @ 38 °C	5.5	6.5	15	48	320
Viscosity, SSU @ 100 °F	31	35	77	232	1500
Minimum Pump Temperature °C (°F)	–18 (0.0)	–18 (0.0)	–12 (10)	2 (35)	38 (100)
Carbon %	86.5	86.5	86.1	85.55	85.7
Hydrogen %	13.2	12.7	11.9	11.70	10.5
Sulfur %	0.1	0.5	0.90	2.0	2.8
Oxygen/N_2 %	0.2	0.2	0.48	0.70	0.92
Ash %	Trace	Trace	0.02	0.05	0.08
HHV, kJ/kg	46,380	45,520	43,940	43,380	43,030
HHV, Btu/lb	19,940	19,570	18,890	18,650	18,500

No. 6 fuel oil, sometimes called “residual,” “Bunker C,” “vacuum bottoms,” or “reduced crude” is produced by many methods, but typically it is the residue left after most of the light volatile products have been distilled from the crude. It is heavy oil, with a SSU viscosity ranging from 900 SSU to 9000 SSU at 38 °C (100 °F). It can be used only in installations with heated storage tanks and with a recirculating piping return back to the tank in order to circulate hot oil at the burner front for correct atomization.

Fuel oil constituents, such as olefins, sulfur, nitrogen, vanadium, sodium, and asphaltenes, cause increased pollutant formation, burner carbonization, poor atomizer performance, and boiler corrosion.

Heavy fuel oils require substantial preheating in order to be atomized properly. For example, No. 6 fuel oil normally has to be heated to the 107 °C to 127 °C (225 °F to 260 °F) range in order to obtain a viscosity of less than 200 SSU. Oils containing olefin hydrocarbons will have a tendency to polymerize and form gummy substances that will detrimentally effect atomization. If excess preheat is applied, tar will form and harden in the fuel system causing maintenance problems. Care shall be taken to maintain the proper preheat for a specific oil to prevent burner carbonization due to fuel polymerization.

The presence of sulfur, sodium, and vanadium in heavy fuels can cause severe corrosion problems, as well as pollutant emissions. During the combustion process, sulfur is oxidized to sulfur dioxide (SO_2). Some SO_2 will be converted to SO_3, which leads to the formation of sulfuric acid (H_2SO_4). The dew point of sulfuric acid is around 132 °C (270 °F) for most atmospheric conditions. Therefore, the stack exit temperature when firing oil should always be above 150 °C (300 °F) to reduce the potential for sulfuric acid attack.

Vanadium and sodium can cause metal attacks on lower temperature metal surfaces. Vanadium attacks are greatly enhanced in the presence of sodium (salts) and can occur at temperatures as low as 593 °C (1100 °F). Vanadium, in concentrations as low as 50 ppm, can also damage refractory.

The presence of asphaltenes in fuel oil causes increased particulate emissions and carbon carryover. Asphaltenes, which are heavy solid combustible substances (often containing some organic-metallic species), tend to be non-volatile and, therefore, are difficult to vaporize and burn. The presence of large amounts of asphaltenes will limit the minimum excess air levels at which burners can operate.

6.5.3.4 Liquid Fuel—Blends

Low sulfur content and low fuel bound nitrogen fuel oils are being used to meet regulations. Light distillates with low sulfur and low fuel bound nitrogen are blended with residue fuels to produce an improved fuel. However, blending light distillate oils with heavy No. 6 will also impact other properties of the fuel. For example, API gravity, heating value per gallon of oil, viscosity, and the ash content, as well as the emissions, are all parameters that will be affected when oils are blended. If the fuel blend is not consistent, many problems will appear. A blend of distillate and residue can produce an unstable fuel due to stratification, or separation, of the two blending components in the storage tank.

Blended fuel oil comes in two classes, depending on the percentage of the light distillate used, which ranges from 20 % to 85 %. The two classes are light (or cold) with a viscosity range of 150 SSU to 300 SSU at 38 °C (100 °F) and heavy (hot) with a viscosity range of 350 SSU to 750 SSU at 38 °C (100 °F). The light oil blend may be capable of atomization without preheating, but the heavy oil requires some preheat.

Blended residual oils may not have predictable physical characteristics. Some will follow the normal viscosity/ temperature curve once they are heated to above the pour point; others will not. Viscosity shall be maintained at a constant value for efficient atomization. Controlling the viscosity by controlling the oil’s preheat temperature can be difficult when firing blended fuels. If the oil’s preheat temperature gets too hot, the distillates will gasify and produce varying viscosities. This property creates the need for greater attention to the fuel’s preheat temperature. Raising and lowering the storage tank temperature can create this poor characteristic.

The use of heavy blended oils can result in sludge production, often classified incorrectly as sediment. Actually, it is a mixture of organic compounds that have precipitated after different oils have been blended. The most notable is the asphaltenes group, consisting of heavy hydrocarbons. After precipitation, they disperse in the oil and contribute to particulates. Another heavy oil contaminant is wax.

Unfortunately, asphaltenes and wax are not detected with normal test methods because the solvents used (benzene and toluene) dissolve them. The presence of these compounds usually is not detected until they cause problems. Heat can eliminate wax, but asphaltenes require a solvent for dissolution, and this generally is impractical in a fuel oil system.

Blended oil produces special combustion characteristics, depending on how the distillate was produced. Distillate oils can be divided into two classes; straight-run and cracked. Straight-run oil is refined directly from crude oil by heating it and then condensing the vapors at various temperatures at atmospheric pressure. Cracking processes depend on higher temperature and pressures, or a catalyst, to produce distillate from heavier fractions. The difference between the two types of oil is that cracked distillate contains a substantial amount of olefinic and aromatic hydrocarbons; these types are more difficult to burn than the paraffinic and naphthenic hydrocarbons produced in the straight-run process.

Industrial No. 2, cracked distillate, is used mainly in fuel-burning installations, such as ceramic kilns and small package boilers, and is blended with No. 6 to lower the sulfur and fuel bound nitrogen content.

One of the most prevalent concerns with firing blended oil is flashing of the light ends. When oil contains both high and low boiling components, the volatile portions volatilize and burn more rapidly, leaving the heavy ends. If there is not sufficient time for complete combustion of the heavy ends, carbon particles will be discharged from the stack, producing opacity and particulates.

Atomizing a blended fuel can also create combustion problems. For example, when firing blended fuel with both light and heavy ends, uniform droplet sizes are not possible and disintegration of the fuel jets is highly likely. Consequently, droplet sizes are much more varied due to the volatile portions (light ends) flashing, leaving the heavy portions as irregular droplets, which are difficult to burn.

6.5.3.5 Liquid Fuel—Contaminants

The burning of fuel oils can produce SOx, inorganic ash, oxidizes of nitrogen, carbon, and unburned and partially oxidized hydrocarbons. Most of these pollutants, notably SOx and inorganic ash, are attributable directly to the fuel and are independent of burner or operation. If these containments are in the fuel, they will be present in the flue gas.

The quantity of inorganic solid particulates in flue gases is entirely dependent upon the characteristics of the fuel. There is no measurable inorganic ash in the flue gas from the combustion of natural gas or other clean gaseous hydrocarbons, except for that small quantity attributable to the dust usually present to some degree in all air used for combustion. Distillate fuel oils do not contain appreciable amount of ash. Typical analyses show variations from a “trace” to about 0.03 % by weight. In residual oil, however, inorganic ash-forming materials are found in quantities up to 0.1 % by weight. Most of this material is held in long-chain organo-metallic compounds. The strong oxidation conditions present in most boilers convert these materials to metallic oxides, sulfates, and chlorides. These compounds show up as fine particulates in the flue gases and can foul boiler heat transfer surfaces.

Wear-resistant alloys and case hardened tips can be used when firing oils containing abrasive particles (catalyst fines). These alloys will wear over a period of time and the enlargement of the oil tip ports will lead to flame deterioration and coking. Only regularly scheduled cleaning and tip replacement will minimize these issues. High-quality burner tiles and refractory shall be used when the oil contains high levels of alkali salts or other compounds that attack refractory.

6.5.3.6 Liquid Fuel—Fuel Bound Nitrogen

NOx emissions performance when firing fuel oil, especially No. 6, is specified by the burner manufacturer based on a defined weight percent of fuel bound nitrogen. A laboratory fuel oil analysis of the specific No. 6 fuel oil being fired is required to determine the weight percent of fuel bound nitrogen. Dependent on the weight percent measured, the NOx performance is based on the conversion ratio of fuel bound nitrogen to NOx. The laboratory test method used to determine the fuel oil nitrogen content is to be specified by the burner manufacturer. Further information on the impact of fuel bound nitrogen on NOx performance can be found in E.1.

6.5.3.7 Liquid Fuel—Waste Fuels

Typical waste liquids include heavy hydrocarbon liquids, byproduct olefins, and waste alcohols. Acid soluble oils can be corrosive and require the use of Monel tip, atomizers, and oil tubes.

It may be preferable to use gas atomization in an internally atomized gun when firing these waste liquids.

It is preferred that the burners be horizontally fired. In this way, any oil drippage will run into the firebox instead of down into the burner and into the air plenum.

Alcohols, ethers, naphtha, butane, and other light liquids should be burned in a dual tube gun rather than the concentric design. This will avoid the premature flashing that sometimes occurs with steam atomization. Premature flashing will lead to unstable combustion (“motor boating”) and eventual flame out. These fuels can usually be burned in any type of burner designed to fire fuel oil. “Motor boating” also occurs when firing oil contaminated with water, caused either from water in the oil or a leaking steam bypass in the oil tip.

Depending on the flow rate and waste fuel, external atomization may be required.

The presence of glycol or fatty alcohols in combination with water found in the fuel can form an emulsion that will increase the viscosity in spite of the higher percentage of light hydrocarbons. Light hydrocarbons will flash in lieu of forming the preferred or desired droplets, leaving the remaining heavy ends and droplets of irregular sizes. This can result in opacity or smoking.

6.6 Burner Arrangements

6.6.1 Boiler Types Used in Refineries

The following sections cover the variety of sizes and types of industrial and utility boilers operating in refineries and chemical plants. The most commonly encountered boilers are single burner industrial packaged boilers and wall fired field erected boilers with up to six burners per boiler. While some larger field erected boilers with more burners—or special designs, such as the tangentially fired, turbo fired, or cyclonic fired boilers—can occasionally be found in these applications, they make up a very small percentage of the total number of installed units.

6.6.2 Single and Multiple Burner Installations

The simplest form of burner arrangement is to have only one burner that provides all of the necessary heat input to the boiler. This is possible on industrial package boilers generating up to 136,000 kg/h (300,000 lb/h) of steam; single burners can produce heat inputs of 132 MW (450 MBtu/h). The burner is located on the end wall of the boiler, which can be fully refractory, a combination of refractory burner throat with a water tube wall, or completely refractory-less water-cooled designs. Although not common, the boiler can also be configured vertically with the burner located at either the top and firing down or located at the bottom and firing up.

As boiler capacity increases, the most constrained dimension is typically the width of the boiler, which is limited to enable shipment by road or rail. Space constraints at the site may also limit the allowable length of the boiler. In these cases, the firebox dimensions may not be sufficient to accommodate the flame envelope required for a single burner. In certain applications, given the right firebox geometry, two burners can be supplied in a common windbox and operated as a single unit, called unison firing. This setup also can be used to achieve heat inputs higher than those available from one burner. In the case of unison firing, both burners operate as a single unit with the loss of flame on either burner causing a shutdown of the entire system.

As boiler capacities increase above the physical size that can be shipped as an assembled unit, boilers are shipped in sections and erected onsite. To minimize the footprint of these “field erected” boilers, their fireboxes increase in height as the boiler capacity rises, while the width and depth of the boiler do not increase proportionally with capacity. Since the depth of the firebox that is available to accommodate the flame length is constrained, these boilers utilize multiple burners, from 4 to as many as 16, arranged in rows on a single wall or on opposed firing walls. The number and arrangement of burners is based on the required heat input and the available width and depth required to accommodate the flame envelope.

Burner spacing is important to ensure that no flame-to-flame interaction occurs, which can increase emissions and flame lengths, leading to impingement. This can vary based on different burner designs and the design pressure drop across the burner. A general guideline on burner spacing is that flames should overlap no more than 10 %, and for wall-fired units the ratio of heat input (HHV basis) to burner pitch (center-to-center spacing) should not exceed 110 GJ/h/m [32.2 MBtu/(h-ft)].

For multiple burner applications, each burner can be brought in and out of service independently, allowing greater flexibility in operating turndown. Typically, all burners in service are controlled by a single fuel valve, and therefore, operate at the same heat input. For added flexibility on units with several rows or columns of burners, a flow control valve can be supplied for each row or column, allowing more flexibility in controlling heat input and distribution within the firebox. Normally, burners should be brought into service symmetrically about the boiler drum centerline to provide balanced heating to the boiler and to minimize drum level fluctuations. This may vary and manufacturer recommended practices should be followed. Additional information can be found in Section 7.

6.6.3 Opposed Fired Installations

In some cases, field erected boilers are designed to have burners on two of the four walls and firing towards the center of the furnace. The burners are located on opposite walls and, are therefore, called “opposed fired” boilers. This is commonly done when the depth of the boiler can be increased more readily than the width or height due to site space constraints. In opposed fired applications, consideration must be given to burner spacing, as well as to the interaction between the opposed burner flames that meet in the center of the firebox. Depending on boiler design, burners may be directly opposed or may be staggered to help prevent interaction with the burners from the opposite wall. Burners in this configuration are typically brought into service by “opposite corners.” Again, this is to provide balanced heating to the boiler and to minimize drum level fluctuations.

6.6.4 Tangentially Fired Installations

Some boiler designs place all of the burners at the corners of the boiler, firing tangentially towards a pitch circle in the center of the firebox. This tangentially fired, or T-fired, boiler design utilizes a vertical column of burners in each corner of the firebox. The burner flames all converge into a swirling “fireball” in the center of the furnace. The number of burners in each column is equal and is dependent on the capacity of the boiler and types of fuels fired.

The burners originally supplied by the boiler OEM for these boilers consisted of square burner “buckets” that were either fixed or tilting. The vertical column contained buckets dedicated to each particular fuel and other buckets that supplied only air. Some of the fixed (non-tilting) bucket applications have been retrofitted in the field to accommodate round burners, although in most cases, burner retrofits and upgrades involve modifying or replacing the fuel components and buckets with components that fit into the existing burner geometry.

In some applications the burners are designed to be tilted up and down by ±30° from horizontal. The burners are all tilted at the same angle, which allows the fireball to be moved higher or lower in the firebox. By controlling the location of the fireball relative to the superheater tubes located at the top of the furnace, superheated steam temperature can be controlled. This can also be used to control the residence time of the combustibles in the furnace to ensure CO burnout on harder to combust fuels.

6.6.5 Cyclonic Fired Installations

Developed by Babcock and Wilcox to burn grades of coal that were not suitable to fire in typical pulverized coal-fired boilers, the cyclonic boiler utilizes one, or multiple, cyclonic combustors to create a highly swirled intense combustion zone. The circular combustors have air and fuel injected into them at a tangent to create a swirling motion that causes the fuel to be "scrubbed" against the walls of the combustor. This intense combustion zone is very good for combustion of hard to burn fuels, but due to the high temperatures it generates, can also be a high producer of thermal NOx. The hot gases exit through an opening at the end of the cyclone(s) and into the main boiler furnace.

6.6.6 Turbo Fired Installations

The turbo boiler was designed to burn low volatility coals and petroleum coke. It is shaped like an hourglass with a row of burners installed opposed at only one elevation and angled to fire downward, below the furnace throat. The number and capacity of the burners in the row depends on the capacity of the boiler. Similar to the tangentially fired boiler, the turbo boiler uses burners that are rectangular, fit into a slot between the wall tubes, and contain directional air louvers that allow the flames to be moved up or down in the furnace.

The burners fire angled down toward the lower section of the boiler firebox, which can commonly be refractory lined. The combustion gases at the center of the firebox then turn and head upward into the upper section of the boiler. This lower firebox typically operates at a very high temperature to ensure complete combustion of hard to burn fuels, which results in high thermal NOx production. The transition between the lower and upper sections of the firebox, which is the narrowest part of the furnace, causes the combustion gases from all burners to mix together to aid in complete CO burnout.

Due to the narrow openings in the tube walls, most burner retrofits and upgrades involve modifying or replacing the fuel components and air louver components with new parts that fit into the existing burner geometry. Some units have been retrofitted in the field to accommodate round burners, although this typically requires modification to the tube walls to accommodate the burner throats. In some cases, some or all of the new burner openings have been placed in the upper section of the firebox, above the transition point, to avoid the high thermal NOx formation that can occur in the refractory lined lower firebox.

7 Instrumentation, Control, and Protective Systems

7.1 General

One of the primary objectives of API 538 is to provide guidance for addressing the unique boiler and combustion system hazards in the refining and petrochemical industry.

7.2 Applying API 538 to Burner Management Systems

7.2.1 General

API 538 should not be applied exclusively as a basis for BMSs. It should be used in conjunction with NFPA 85. For those that apply NFPA 85 to industrial fired boilers in the refinery and petrochemical industry, API 538 provides supplementary guidance for boiler and combustion system hazards.

7.2.2 Hazard Analysis

With the current release of NFPA 85, its Annex A.4.11 has been updated to include hazard analyses that are consistent with current practices in the refining and petrochemical industry.

Some in the industry (e.g. contractors, OEMs, and vendors) regard NFPA 85 as a document to be strictly followed. However, NFPA 85 (2011), Section 1.3.2 states "This code shall not be used as a design handbook." NFPA 85 recognizes that a competent designer and/or hazard assessment team should evaluate the hazards and allocate protective functions to mitigate the hazards. Where special problems arise, a competent designer is given the latitude to resolve these issues with a documented basis to the owner/operator. For additional clarification, see 7.2.3.

Utilizing the equivalency provision in NFPA 85, Section 1.5, alternative designs that meet the requirements of NFPA 85 may be achieved where all the following are provided per Annex A.4.11.

a) Approval of the AHJ.

b) A documented hazard analysis that addresses all the requirements of NFPA 85.

c) A documented life-cycle system safety analysis that addresses all requirements of NFPA 85 and incorporates the appropriate application-based SIL for SISs. One methodology for achieving a life-cycle system safety analysis is to use a process that includes SIL determination and a SIS design and implementation consistent with the ISA 84 standard series.

As an industry consensus document, API 538 may assist in defining RAGAGEP for the application of instrumentation, control, and protective functions to boilers. However, hazard analysis and SIL assignment are fully independent issues. While this document provides the functional safety basis for protective functions, there is no explicit or implicit recommendation to assign a SIL to a PIF. A PIF is classified as a SIF, if a SIL is assigned. Facilities that desire to assign a SIL to a SIF should follow the guidelines stated within ANSI/ISA 84.00.01-2004 (IEC 61511-1 Mod).

7.2.3 Documenting the Validity of the Proposed Design

7.2.3.1 General

NFPA 85 is a prescriptive, minimum safety standard to be used by competent designers and is not a design handbook. Competent designers are given the latitude to address special or unusual problems provided they document the validity of the designs where such problems exist (NFPA 85, Section 1.3). Additionally, the equivalency section in NFPA 85, Section 1.5 states that "Nothing in this code is intended to prevent the use of systems, methods, or devices of equivalent or superior quality, strength, fire resistance, effectiveness, durability, and safety over those prescribed by this code."

In contrast, API 538 is a performance-based recommended practice that provides options to mitigate specific process hazards and forms a basis for justifying special designs to the AHJ when these designs deviate or diverge from the prescriptive requirements in NFPA 85.

This section references NFPA 85 paragraphs and provides API 538 guidance that is consistent with NFPA 85 intent. This approach may be defined as documenting the validity of the proposed design to resolve issues common to industrial fired boilers within the refining and petrochemical industry. With additional clarification cited below, examples include:

1) BMS—logic system requirements;

2) one boiler per logic solver;

3) switches vs transmitters including low water cutoff;

4) flame proving;

5) bypassing of interlocks;

6) provisions for online testing of SSVs;

7) atmospheric vent valves between burner SSVs;

8) valve proving systems, operational leak tests, and valve leakage (bubble) tests;

9) BMS supervision of light-off conditions;

10) purging a single burner water tube boiler;

11) purging multiple burner water tube boilers (12 burners or less);

12) miscellaneous prescriptive trips;

13) limitations of the interlock system;

14) timing sequences;

15) flame failure response time (FFRT) vs SSV stroke time—time to safe state.

7.2.3.2 Burner Management System—Logic System Requirements

NFPA 85 interpretation and API 538 guidance for BMS logic system requirements are as follows.

a) NFPA 85 Interpretation—Sections 4.11.5 and 4.11.6 delineate the logic system requirements for the BMS. For standard logic solvers, this typically includes an external watchdog timer, an independent hardwired MFT relay, and an independent hardwired operator-initiated emergency trip.

b) API 538 Guidance—These issues may be resolved with the installation of a safety certified logic solver (i.e. per IEC 61508) and mitigates the requirement for an independent watchdog timer, an independent hardwired MFT relay, and an independent hard wired operator-initiated emergency trip. For safety certified logic solvers, an equivalent level of safety and reliability may be achieved with the ESD pushbutton wired directly and exclusively to the logic solver.

Incident history indicates that some logic solvers may lock up in the presence of lightning strikes, preventing a response to signal inputs. Although safety certified logic solvers designed per IEC 61508 should fail-safe the outputs upon severe electromagnetic and power surges, some insurance carriers may continue to recommend an operator initiated emergency trip to be hardwired independent of the SIS and BPCS [3].

7.2.3.3 One Boiler per Logic Solver

NFPA 85 Interpretation and API 538 guidance for one boiler per logic solver is as follows.

a) NFPA 85 Interpretation—Section 4.11.7.4 specifies that the logic system shall be limited to one boiler.

b) API 538 Guidance—More than one boiler per logic solver may be considered when using safety certified logic solvers (i.e. per IEC 61508) and critical equipment grouping within the protective system. For example, a consideration may be to combine two adjacent standby boilers, or a boiler and process unit(s), into a common safety certified logic solver. Unless the logic is segregated, however, proof testing would require online testing protocol for the offline boiler, which would increase the potential to nuisance trip the online boiler. Additionally, software and firmware upgrades to the logic solver cannot be performed without taking both boilers out of service.

7.2.3.4 Switches vs Transmitters, Including Low Water Cutout

NFPA 85 Interpretation and API 538 guidance for switches vs transmitters, including low water cutout include the following.

a) NFPA 85 Interpretation—Some have interpreted the definitions stated in Sections 3.3.159.11 and 3.3.159.12 as a design requirement to use switches for LWCO.

b) API 538 Guidance—The use of transmitters rather than switches for interlocks enhances safety system reliability. With the 2011 edition of NFPA 85, the use of transmitters in lieu of switches is permitted. The use of the term "switch" in the definition chapter of NFPA 85 is a carryover from earlier editions of that code and the use of switches is not a requirement for either single or multiple burner boilers.

An important consideration beyond redundancy for diagnostic coverage (e.g. external comparison) is process driven faults that may adversely impact process measurement. For example, consider a boiler level transmitter using differential pressure. Depending upon set point resolution, flashing or loss of the low reference leg from initial zero (malfunction high) has the potential to make the low level trip set point ineffective. Thus, diversity in measurement (e.g. maintaining a LWCO switch) may be an important consideration for boiler level.

7.2.3.5 Flame Proving

NFPA 85 Interpretation and API 538 guidance for flame proving include the following.

a) NPFA 85 Interpretation—Sections 4.12.3.5.5 and 4.12.3.5.6 refer to tangentially fired boilers and large, multiple burner boilers where an igniter or burner flame detector cannot achieve individual flame discrimination above a firing rate threshold that ensures complete combustion. An important clarification is that individual flame discrimination cannot be waived below the firing rate that ensures complete combustion. At higher operating loads individual flame detectors may sense flame even when the corresponding burner is not in operation. However, when the boiler load drops below the minimum fireball threshold, to loads where individual burner flame discrimination is achievable, and/or boiler load is insufficient to ensure complete combustion, the flame monitoring philosophy reverts back to individual burner flame detection.

b) API 538 Guidance—Sections 4.12.3.5.5 and 4.12.3.5.6 in NFPA 85 shall be applied exclusively to tangentially fired boilers. Since the majority of boilers in the refining and petrochemical industry are fired with 12 or less wall-mounted burners, the capability to discriminate flame between individual burners independent of boiler load is practical, reasonable, and achievable.

7.2.3.6 Bypassing of Interlocks

NFPA 85 Interpretation and API 538 guidance for bypassing of interlocks include the following.

a) NFPA 85 Interpretation—According to Section 4.5.4, bypassing of interlocks during start-up and normal operation is permissible when the bypass is tagged and is governed by operating procedures. The basis for prohibiting the use of bypasses in Section 5.3.6.4.3 is that many single burner boilers have unattended operation. By contrast, most multiple burner boilers are attended. Additional requirements apply per Section 6.4.1 when multiple burner boilers are unattended. For unattended boilers, manual bypassing of interlocks during normal operation is not recommended.

b) API 538 Guidance—Within the refining and petrochemical industry most single and multiple burner boilers have attended operation where the operator is in view of operating instrumentation (local or remote) and in a position to operate the control system and respond to alarms.

   Critical boiler interlocks shall not be bypassed during start-up, unless required as part of the automatic start-up sequence. For example, to reset the SSVs during start-up sequencing, it is required to temporarily disable trip conditions that are present when the SSVs are closed (e.g. loss of flame, low fuel gas burner pressure). It is recommended to incorporate this functionality in the boiler's BMS logic via start-up overrides (see 7.5.4.2).

   During normal operation, a temporary maintenance bypass of an interlock is permissible under the following conditions.

   1) Bypassing an input measurement device temporarily for maintenance, calibration, and testing is permissible when administrated by authorized, trained personnel following applicable maintenance and operating procedures, and when emergency response procedures relevant to the measurement under bypass are in

place. The associated alarm for the measured process variable should not be bypassed at the same time as the protective device. Where a higher degree of administrative control is desired, bypass switches may be installed in a remote key locked area.

2) Bypassing the output signal to an output device via programmable logic (e.g. forcing an output in the logic solver) is not permissible, as doing so effectively blocks all interlock inputs from initiating a trip.

3) Bypasses shall not be used to bypass unsafe process conditions.

4) Bypass alarm and status indications should be provided to the operator interface.

5) Bypassing an individual flame scanner should be a vote to trip the burner.

NOTE Especially with 2oo2 voting (e.g. redundant flame scanners), a bypass that takes an instrument out of service (i.e. unavailable to trip) is not recommended since a bypass of either input will disable the trip function.

For clarification:

i) Redundant instrumentation may provide additional flexibility in the bypass philosophy.

— Change the Voting Logic (while bypassed)—A single transmitter may be bypassed while the redundant transmitter(s) are available to trip. As an example, a bypassed transmitter could reduce the voting logic (e.g. from 2oo3d to 2oo2d or 1oo2d) during the maintenance interval.

— Vote to Trip (no bypass)—Alternatively, redundant transmitters may negate the requirement for bypasses where an instrument that is temporarily taken out of service for maintenance is a vote to trip (e.g. one vote to trip with a 2oo2d or 2oo3d tripping interlock system).

NOTE Diagnostic alarms may be configured to take an instrument out of service (i.e. alarm only) or as a vote to trip. Therefore, careful consideration should be given to the response of voting blocks in the presence of diagnostic alarms. As an example, a common bias against 2oo2d is that a diagnostic alarm (i.e. configured to alarm only) may inhibit a trip while a diagnostic alarm is present. To improve the safety availability of 2oo2d, a diagnostic alarm may be configured as a vote to trip.

ii) Safe operation during the maintenance interval may be achieved either with redundancy or distributed risk to other protection layers. For example, the hazard associated with taking a burner pressure transmitter out of service may be temporarily mitigated with a redundant pressure transmitter or with flame scanners. Conversely, the hazard associated with taking an individual flame scanner out of service is mitigated only with a redundant flame scanner.

iii) Since flame scanners detect loss of flame, bypassing all flame scanners to an individual burner should trip the individual burner. While other trip interlocks (e.g. high and low fuel gas burner pressure) have set point that precede loss of flame at operational limits (see 4.6.5), loss of flame inside of operational limits is detected only by the flame scanner. Therefore, bypassing the flame scanner(s) to an operating burner could prevent detecting loss of flame inside of operational limits and is not recommended.

7.2.3.7 Provisions for Online Testing of Safety Shutoff Valves

NFPA 85 Interpretation and API 538 guidance for provisions for online testing of SSVs is as follows.

a) NFPA 85 Interpretation—NFPA 85 does not address online testing of SSVs. As noted in the preceding section, the requirements stated in NFPA 85, Section 5.3.6.4.3 for single burner boilers and Section 6.4.2.2.3 for multiple burner boilers refer to the inputs of an interlock system.

The basis for not addressing online testing of SSVs in NFPA 85 (i.e. without taking burners out of service) is that most boilers are required to be taken out of service for regulatory or other considerations with operating cycles of one year or less. Therefore, offline testing of the interlocks and final elements associated with these boilers may be facilitated in a timely and safe manner.

b) API 538 Guidance—Within the refining and petrochemical industry, the AHJ in some states (e.g. Texas) allows an extension of the internal boiler inspection interval for up to 5 years between shutdowns. In these jurisdictions, provisions for testing of the SSVs between inspection shutdowns are an important consideration to achieve safety availability requirements.

   Within the refining and petrochemical industry, spare boiler capacity is frequently provided to prevent loss of steam to critical operating units. Spare boiler capacity also permits offline testing of interlocks and final elements. Facilities without spare boiler capacity may consider online testing of the SSVs to achieve safety availability requirements. Considerations for online testing are as follows.

   1) Partial Stroke Testing (PST)—A PST is frequently used to extend the full stroke proof test interval to a scheduled shutdown. The PST infers the valve's suitability for continued operation (i.e. to fully close on demand) by moving the valve only 10 % to 20 % of its stroke.

      However, in refinery fuel gas service, SSVs have been known to pass a PST at scheduled test intervals (e.g. annually) yet fail to fully close at the scheduled shutdown (e.g. five years). Therefore, to keep the system functioning as designed in refinery fuel gas service, full stroke tests between shutdowns (e.g. annually) may be required to improve the likelihood that the SSVs will fully close on demand.

      As an advisory, some AHJs (e.g. CSA) may require a waiver to allow the use of a PST.

   2) Full Stroke Testing (FST), Single Burner Boilers—Online testing may be facilitated with the installation of a bypass testing valve around each SSV (see 7.9.2) where one valve is available to trip while the other is being tested. It is recommended to withhold the opening of each bypass valve until the point in the test sequence that the associated SSV is ready to be full stroke tested. The objective is to limit the unavailability of the tested SSV (e.g. less than 5 min).

   3) FST, Multiple Burner Boilers.

      i) With sufficient burner capacity, individual burners may be taken offline temporarily to full stroke test the SSVs to each burner. Where applicable, multiple fuel sources with individual fuel trains to each burner may be independently tested, i.e. the fuel source is isolated for the SSVs being tested while the other fuel maintains steam production.

      ii) Where there is no automated SSV at each burner (e.g. legacy boilers), the online testing protocol for single burner boilers (i.e. SSVs in the main header) may be facilitated by installing a bypass testing valve around each SSV in the main header (see 7.9.2).

      iii) Where there is a single SSV at each burner, individual burners may be taken offline temporarily to full stroke test the SSV to each burner and online testing of the main header SSV may be facilitated by installing a bypass testing valve.

For clarification:

a) where applicable, a FST provides the capability for seat leakage tests (see 7.2.3.9);

b) after extended periods of non-movement, the availability of the SSVs to close on demand is reduced. With annual and biennial shutdown intervals, there is sufficient empirical data to support that SSVs in natural gas service have a high probability of closing on demand. However, as the internal boiler inspection intervals are extended (e.g.

greater than 2 years), there is insufficient data to support that the SSVs will maintain a high probability to close on demand after longer periods of non-movement;

c) for facilities that use SIL validation software to establish proof test intervals, it is important to recognize that failure rate source data does not take into account site specific process conditions and environmental factors. Even when these factors are taken into consideration (e.g. via beta factor, duty factor, proof test coverage, or alternate technique for de-rating the safety availability), the impact to safety availability is highly subjective. Because of the resulting uncertainty, extending the proof test intervals to the minimum limits of the target SIL may ultimately compromise the ability of the SSV to perform on demand. Therefore, proof test intervals should be assigned where valve performance is well understood to increase the probability that the SSV will fully close on demand.

7.2.3.8 Atmospheric Vent Valves Between Burner SSVs

NFPA 85 Interpretation and API 538 guidance for atmospheric vent valves between burner SSVs is as follows.

a) NFPA 85 Interpretation—For single burner boilers, a double block and vent or a listed valve proving system is required in the fuel gas supply to each boiler. For multiple burner boilers, a double block and vent is required on the fuel gas line to each burner and no alternative is provided for using a valve proving system in lieu of a vent.

   Where vents are provided, the minimum size of the vent line is prescribed based on the fuel supply line size to the burner. Cautions are included on the need to vent to a safe location. For heavier-than-air gases, it is permissible to eliminate the vent for single burner boilers.

   To meet the intent of the requirements of NFPA 85, industry practice has been to provide fail open (energize to close) vent valves.

b) API 538 Guidance—When a burner trips or an MFT is initiated, the most important action is closing the SSVs. The inclusion of the vent between the valves minimizes the potential for leakage into an idle boiler in the time between closing of the SSVs and insertion of a blind. However, the inclusion of the vent increases the risk of venting noxious constituents (e.g. hydrogen sulfide) present in refinery fuel gas. Therefore, when firing refinery fuel gas with noxious constituents, venting of the gas to the atmosphere should be minimized. For both single and multiple burner boilers, options include the following.

   1) With a fail open vent valve, minimize the valve size and the vent line cross-sectional area. The vent size needed to relieve gas to the atmosphere at a rate equal to the potential leakage rate of the upstream SSV can be significantly less than the values specified in NFPA 85, Table 4.9.2.

   2) Use a fail closed (energize to open) vent valve to prevent inadvertent release of fuel gas to atmosphere when power is lost to the valve during normal operation.

   3) With a fail open vent valve, install a manual block valve beneath the atmospheric vent. This allows a vent valve that has malfunctioned open to be isolated.

   NOTE A manual block beneath the vent valve also enables seat leakage (bubble) tests of the SSVs (see 7.2.3.9).

   4) Eliminate the atmospheric vent and install a valve proving system (see 7.2.3.9).

7.2.3.9 Valve Proving Systems, Operational Leak Tests, and Valve Leakage (Bubble) Tests

NFPA 85 Interpretation and API 538 guidance for valve proving systems, operational leak tests, and valve leakage (bubble) tests is as follows.

a) NFPA 85 Interpretation.

For single burner boilers is as follows.

1) A valve-proving system is used to check for seat leakage through the SSVs by venting and pressurizing the piping between the two SSVs and monitoring the pressure to verify it does not rise or decay more than a predetermined amount in a specified period of time. Some systems include a small pump/compressor to raise the gas pressure between the two SSVs to greater than the fuel supply pressure.

2) There is no reference to an operational leak test in the single burner boiler chapter of NFPA 85.

3) Valve leakage (bubble) tests of the SSVs are required at least annually.

4) The automatic vent valve may be omitted only if a listed automatic valve-proving system is used. When the automatic vent valve is omitted, valve proving shall be performed either after every burner shutdown or prior to every burner light-off while maintaining minimum purge rate airflow. The valve-proving system shall prevent light-off of the igniter or main burner if the test is not satisfied.

For multiple burner boilers is as follows.

1) An operational leak test is used to check for SSV leakage by pressurizing the piping between the main fuel gas header SSV and the upstream SSV to each individual burner and monitoring the pressure to verify it rises within a specified amount of time and does not decay more than a predetermined amount in a specified period of time. The test is performed during every boiler start-up with purge rate airflow.

2) There is no reference to a valve proving system in the multiple burner boiler chapter of NFPA 85.

3) Valve leakage (bubble) tests of the individual burner SSVs and associated vent valves are required consistent with the service requirements and manufacturers' recommendations.

4) There is no provision in NFPA 85 for omitting the automatic vent valve.

b) API 538 Guidance—Within the refining and petrochemical industry, fuel gas is typically isolated with a manual block and spectacle blind upstream of all SSVs during extended shutdowns.

When the vent is eliminated or blocked, valve proving is required for single burner boilers and should be considered for multiple burner boilers.

1) Since many refinery fuel gases contain noxious constituents (e.g. hydrogen sulfide) and components that are heavier than air, the vent is frequently eliminated or manually blocked to atmosphere.

2) It is recommended that the SSVs be proven at shutdown or scheduled outage. This facilitates valve testing and repair in a more practical and timely manner than at start-up.

3) In either case, the functionality of a valve proving system may be programmed into the logic solver. The basis for seat leakage flow rates at the testing pressure, the corresponding pressure set point, and the delay timers that define pass/fail criteria should be documented during the project design phase.

NOTE All currently listed valve proving systems are manufactured using aluminum body SSVs. Use of such valves is not permitted in some piping codes (e.g. ASME B31.3). Use of non-listed systems is permitted.

Valve proving and operational leak tests are used to identify a major leak (e.g. a broken or damaged seat). In contrast, valve leakage (bubble) tests have much better resolution and measure seat leakage in bubbles per minute. As an example, some insurers may require that valves are overhauled or replaced at a seat leakage rate of 1 bubble per second [4]. A leakage rate this small would be impractical to diagnose by observing pressure rise or decay over a specified time interval. The maximum allowable leakage rates for block valves are defined in Table 6 of API 598.

7.2.3.10 BMS Supervision of Light-off Conditions

NFPA 85 Interpretation and API 538 guidance for BMS supervision of light-off conditions is as follows.

a) NFPA 85 Interpretation—NFPA 85 prescribes a start-up sequence for lighting off burners that includes confirmation that the purge step has been completed and confirmation that the fuel gas control valve and the dampers are in light-off position prior to permitting the burner SSVs to be open.

   Although implied, there is no explicit requirement within NFPA 85 to “lock out” the fuel gas controller during the light-off sequence, restrict movement of the control valve during the light-off sequence, or for the BMS to prove that light-off conditions are maintained during the trial-for-ignition (TFI) period.

b) API 538 Guidance—The BMS should supervise light-off conditions during the TFI period to ensure the concentration of unburned fuel gas does not exceed 25 % of the lower explosion limit (LEL).

   Industry practice has been to use the process control system to maintain light-off conditions during the TFI period. Since “modulating control” implies automatic control, many have concluded that disabling automatic mode effectively locks out the controller until release-to-modulate. However, in most cases, the controller output is accessible in manual mode and may be changed by the operator during the light-off sequence. If the control valve is permitted to move to an unsupervised position and the burner fails to light within time constraints, a hazardous gas mixture may be created within the combustion chamber.

   For single burner boilers, an interlock is recommended to ensure the delivery of fuel gas is within prescribed limits during the TFI period and to initiate a trip if the light-off conditions are not maintained within prescribed limits during the TFI period. This interlock may be instrumented with a minimum fire limit switch or position transmitter, or burner pressure transmitter.

   NOTE While rocker switches may be preferred for their narrow bandwidth, they have also proven to be unreliable. While proximity switches are very reliable, they frequently have too much bandwidth. Adjustable bandwidth is a function of the diameter of the proximity switch versus valve travel. Too much bandwidth may allow the valve to travel beyond what is considered appropriate for BMS supervision. Therefore, the end user should take care in selecting and setting the proximity switch to ensure that the safety objectives are achieved. As a design consideration, BMS supervision may be improved with the use of a burner pressure transmitter in lieu of valve position.

   For multiple burner boilers, during light-off of the first burner, an interlock is recommended to ensure the delivery of fuel gas is within prescribed limits during the TFI period and to initiate a trip if the light-off conditions are not maintained within prescribed limits during the TFI period. This interlock may be instrumented with a minimum fire limit switch or position transmitter, or burner pressure transmitter.

   NOTE After the first burner is lighted, the fuel pressure at the burner header should be controlled within specified limits to ensure that the necessary fuel flow to each burner is maintained as additional burners are placed in service.

7.2.3.11 Purging a Single Burner Water Tube Boiler

NFPA 85 Interpretation and API 538 guidance for purging a single burner water tube boiler is as follows.

a) NFPA 85 Interpretation—For a single burner water tube boiler, NFPA 85 prescribes a purge rate of not less than 70 % of the airflow required at maximum continuous capacity of the unit. The purge must last long enough for there to be at least eight air changes, but NFPA 85 does not specify if the air change volume is based on just the firebox, the boiler enclosure, or the entire boiler including the stack. Additionally, there is no minimum purge time requirement specified.

   The assumptions upon which the NFPA 85 purge requirements are based are unknown. The missing assumptions include:

1) combustibles concentration in the boiler at the beginning of the purge (e.g. 100 % fuel gas);

2) combustibles concentration in the boiler at the end of the purge (e.g. <25 % LEL);

3) boundaries of the purge volume;

4) mixing model (e.g. well-stirred, plug flow, free standing jet) used to represent the change in concentration of combustibles with time inside the purge volume during the purge.

b) API 538 Guidance—Assuming a well stirred vessel, a representative purge time (per the boiler manufacturer) is 3 min to purge 8 volumes of the boiler enclosure (as defined by NFPA 85) at 70 % MCR airflow.

Once assigned by the boiler manufacturer, the purge time should not be reduced exclusively upon the capability of the FD fan to exceed 70 % MCR airflow. The basis is that at higher purge rates it is possible for the boiler to transition from well stirred mixing to jet mixing. When jet mixing occurs, a high velocity jet stream forms through the center of the boiler and the rate of reduction of combustibles is less for a given airflow rate than when well stirred mixing occurs. For example, if jet mixing were to occur at 140 % MCR airflow, the time required to reduce the concentration of combustibles from 100 % fuel gas to 25 % LEL would be greater than one-half that of the well stirred model at 70 % MCR airflow. Therefore, modeling is recommended before reducing the vendor recommended purge time.

NOTE Burners with a high exit velocity may cause a jet stream to form through the center of the firebox during the purge cycle. Especially if the starting point is 100 % fuel due to a malfunction, formation of a jet stream may reduce the capability to sweep the combustion chamber free of combustibles within the representative purge time of 3 min. When the formation of a jet stream is suspected, an interim solution may be to increase the purge timer (e.g. to 5 min) until modeling can be performed.

Where applicable, the ductwork associated with external FGR should be purged in accordance with the boiler manufacturer's recommendation. In the absence of specific instructions from the boiler manufacturer, it is recommended that a two-step purge process be done. FGR dampers should be closed while the boiler enclosure is purged. After the boiler enclosure purge is complete, all dampers in the FGR duct should be fully opened and airflow should be allowed to pass through the ducts. Modeling should be done to determine the length of time required to purge the FGR ducts through the boiler enclosure.

NOTE The above guidance is based on the most common configuration for external FGR in a single burner boiler (i.e. FGR is induced by ducting flue gas from the boiler outlet to the FD fan inlet). If an external FGR fan is provided and recirculated flue gas is introduced into the air stream downstream of the FD fan, the guidelines for purging FGR ducts for multiple burner boilers should be followed.

7.2.3.12 Purging Multiple Burner Water Tube Boilers (12 Burners or Less)

NFPA 85 Interpretation and API 538 guidance for purging multiple burner water tube boilers (12 burners or less) is as follows.

a) NFPA 85 Interpretation—For multiple burner water tube boilers, NFPA 85 requires the designer to calculate a minimum purge rate airflow not less than 25 % of the design full load mass airflow, which is used to establish the following.

1) The minimum combustion airflow during purge of the entire unit from the FD fan inlet through the stack for the greater of 5 min or 5 volume changes (based on purge components containing sources of ignition).

2) The low combustion airflow trip set at 5 % below the purge rate airflow.

Special considerations are provided for a boiler with just two burners, but no distinction is made in the requirements for purging and sequential burner light-off for boilers with three or more burners.

Requirements, in the absence of specific manufacturer recommendations, are not provided for purging FGR ducts.

b) API 538 Guidance—In NFPA 85 there is a clear distinction in the purging requirements for single and multiple burner boilers. The majority of boilers in the refining and petrochemical industry have 12 burners or less. Within this size classification, the process hazards associated with purging multiple and single burner boilers are essentially the same. Therefore, the purge and subsequent airflow requirements during light-off of multiple burner boilers (12 burners or less) may be modified with a few clarifications.

   1) Use the maximum achievable airflow rate when purging the boiler, but in no case less than 25 % of the design full load mass flow.

   2) Similar to the discussion of single burner boilers (see 7.2.3.11), the end user should consider the appropriate mixing model and boundary conditions for purge calculation before reducing the vendor recommended purge time.

   3) The low combustion airflow trip should be set at 20 % of the design full load mass airflow (i.e. 5 % below the minimum permissible purge rate of 25 % MCR airflow).

   4) If the airflow per burner required for light-off is less than the airflow per burner with the maximum achievable purge rate, the total airflow should be reduced until the airflow per burner equals that required for light-off and conditions are stabilized (e.g. 15 s to 30 s) prior to starting the light-off sequence for the first burner.

      NOTE 1 Since the total purge airflow is cumulative, this stabilizing period (e.g. 15 s to 30 s) may be included in the 5-min purge period.

      NOTE 2 The total airflow should not be reduced below 25 % of the design full load mass airflow. If necessary, operating procedures should include provision for partial closure of an individual air register during burner light-off to establish the correct air-fuel ratio at the burner. Once the burner is lighted, the burner's air register should be returned to its prior position. Additionally, the burner vendor may restrict adjustment of an individual air register when that change may significantly disrupt the airflow distribution to other burners.

   5) Where applicable, the ductwork associated with external FGR shall be included in the purge process. In the absence of specific instructions from the boiler manufacturer, it is recommended that a two-step purge process be done. FGR dampers are initially closed when first boiler purge is begun. After the boiler firebox is completely purged, all dampers in the FGR duct should be fully opened. This airflow shall be independent of the airflow required to pass through the boiler enclosure.

7.2.3.13 Miscellaneous Prescriptive Trips

NFPA 85 Interpretation and API 538 guidance for miscellaneous prescriptive trips is as follows.

a) NFPA 85 Interpretation—For single burner boilers, NFPA 85 requires automatic trips for loss of control system actuating energy, power failure, and excessive steam pressure or water temperature. These trips, while mandatory, are not listed as required automatic trips for multiple burner boilers.

b) API 538 Guidance—The above listed tripping interlocks for single burner boilers are not listed among the prescribed automated interlocks for multiple burner boilers in NFPA 85.

   Control system actuating energy and loss of power are mandatory trips, but are not necessarily automatic interlocks for many larger multiple burner boilers in the power generation industry that utilize an energize to trip philosophy. Since the refining and petrochemical industry uses a de-energize to trip philosophy and the process hazards associated with the loss of control system energy and power failure are identical for single and multiple burner boilers, the same protection philosophy should be consistently applied to all boilers within a facility.

The reason an excessive steam pressure or water temperature trip is not prescribed is that a boiler trip could elevate the hazard by upsetting process operations or the electric power grid. The consequences of tripping the boiler could be more severe than the consequences that could result from an operator not responding appropriately to an alarm annunciating these conditions.

While not mandated as automated trips for multiple burner boilers, there is nothing prohibiting a facility from including these three trips or any other interlocks deemed appropriate by hazard analysis. Additional considerations are as follows.

1) Loss of Control System Actuating Energy—Within the refining and petrochemical industry this is typically associated with low instrument air header pressure.

   Where permissible, it is recommended to select a spring range in the SSVs higher than that in the final control elements (e.g. fuel gas control valve or combustion air damper). With sufficient margin between control and safety spring ranges, low air pressure would cause the SSVs to close (initiating a MFT on low burner pressure and/or loss of flame) before low air pressure could affect process control.

   The spring range in the SSVs is typically specified at 414 kPa (60 psi). Fuel gas control valves typically have a spring range of 21 kPa to 103 kPa (3 psi to 15 psi) or 41 kPa to 207 kPa (6 psi to 30 psi). Normally functioning air dampers should require no more than 207 kPa (30 psi); however, they are frequently specified with a spring range as high as 414 kPa (60 psi) to mitigate sticking dampers. The downside to increasing the spring range to air dampers (e.g. 60 psi) is that the trip set point should be elevated with the spring range, which may increase the nuisance trip rate.

   As an example, suppose that a combustion air damper has a 414 kPa (60 psi) spring range. If the air supply is permitted to drop below 414 kPa (60 psi), the control system may be incapable of maintaining the correct air-to-fuel ratio. Therefore, when the bench set of the air dampers and SSVs is so close that one cannot predict which will be impacted first by low supply pressure, a trip on low instrument air pressure may be recommended, depending on the type of burner (e.g. a low NOx burner). To be effective, the trip set point should be greater than the spring range of the combustion air damper.

2) Power Failure—This is resolved with a fail-safe de-energize to trip philosophy and spring return fail close SSVs. No independent measurement is required (e.g. line monitoring).

3) Excessive Steam Pressure or Water Temperature—Excessive steam pressure or water temperature may result in exceeding ASME *Code* allowable tube limits. Corrective control action should be taken by the control system or the operator. An immediate failure is unlikely with attended operation. Therefore, excessive steam pressure or water temperature trips are rarely used as the PSVs provide protection.

   An operational consideration is to prevent the PSV from lifting unnecessarily. Owners typically accept the risk of lifting the PSV and the possible need for a controlled shutdown to reseat the PSV. To improve reliability, it is important to establish sufficient operating margin between normal operating pressure and the PSV set point. A pilot operated PSV may allow for more precise setting of the PSV set point. Alternatively, the owner may implement an automated steam vent to relieve before the PSV and to control boiler pressure at start-up.

   Within the refining and petrochemical industry, some facilities may opt for excess relief capacity (e.g. via multiple PSVs) so that leaking PSVs can be gagged or removed from service without compromising the code required full relief capacity.

   NOTE ASME *BPVC* Section I (power boilers) Code Cases describe variations to PSV requirements in PG-71.3. The reader may wish to consult Code Case 2254 for an optional provision for excess relief capacity.

7.2.3.14 Limitations of the Interlock System

NFPA 85 Interpretation and API 538 guidance for limitations of the interlock system is as follows.

a) NFPA 85 Interpretation—NFPA 85 notes that even when devices are installed per the requirements in that code and adjusted and maintained in accordance with manufactures' instructions, not all conditions conducive to a furnace explosion or implosion will be detected. It also states operators need to be aware of the limitations of the interlock system and be trained to know and recognize unsafe conditions that may go undetected by the interlock system. However, no guidance is provided as to the methods operators can use to help them identify such conditions.

b) API 538 Guidance—While prescriptive trips are typically associated with the operational or flame stability limits at the end points of a burner curve, it is important to understand that the burner may be subject to loss of flame inside of those operational limits. Especially for multi-stage burners or burners with a narrow band of control, the interlock system may have reduced capability to detect unsafe operating conditions.

   — For some multi-stage burners, flame scanners dedicated to a single stage may not provide sufficient protection. Multi-stage burners may need dedicated scanners to each stage that detect flame signatures for all operating conditions and all fuels.

   — At a given fuel flow, the burner has a maximum and minimum air/fuel ratio for safe, reliable and efficient operation. In addition, other controlled variables, such as recirculated flue gas, will have an allowable upper and lower limit. The maximum and minimum limit for the air/fuel ratio or FGR flow at a given fuel flow is a function of burner stability, burner emissions, and the onset of incomplete combustion. Generally, these limits are defined by the burner manufacturer, and confirmed at the time of commissioning the CCS (ABMA 307, Section 3.1, p. 21).

   Where applicable, the CCS may independently monitor controlled combustion variables and alarm or trip when those variables exceed the upper or lower limit of the band of control. Options include the following.

   1) Parallel Positioning Control

      CCS to BMS Trip (via Position Feedback)—The potential exists in parallel positioning applications for one of the final driven units to fail or lose calibration. In this scenario, the air/fuel or FGR ratio will no longer track per original set-up and the system may not perform efficiently or safely within the band of control. To minimize this potential, parallel positioning control applications utilize a position feedback signal from each of the driven control elements. For each driven control element in the parallel positioning system, the CCS continuously measures the deviation between the actual element position and the controller output to that device. If the measured deviation at any driven control element exceeds a preset limit, the CCS opens a contact to initiate a MFT in the BMS. The value of acceptable deviation may be field set during commissioning to limit operation within the allowable band of control (ABMA 307, Section 2.1.1.2, p. 12).

      NOTE As an advisory, a parallel positioning control system may not be appropriate for boilers with a narrow band of control since the tight dead-band requirements for a position feedback trip system may increase the nuisance trip rate. To improve reliability, a metered control system may be preferred.

   2) Metered Control

      i) Constraint Control—At any firing rate, if the measured air/fuel ratio reaches the high or low alarm limit, the boiler demand signal is held at the value where excursion began as the fuel and air flow controllers work to return the system to a normal firing ratio. Once the air/fuel ratio returns to within its acceptable range, the hold is released, and the controls again track the boiler load signal.

Additional problems with full metering control systems are encountered at low boiler loads. In this low range, the signal from the air flow transmitter may become unreliable and noisy. For this reason, boiler turndown should be limited to keep the fuel and air flow within the repeatable and reliable range of each respective flow measuring device (see 7.3.4.1).

ii) CCS to BMS Trip—If the air/fuel ratio reaches either the high or low trip limit, the DCS will open a contact that initiates a MFT in the BMS (ABMA 307, Section 2.1.2, p. 18).

NOTE 1 When implementing a CCS to BMS trip via direct measurement of the air/fuel ratio, consideration should be given to selecting highly reliable instruments with self-diagnostic fault capability. The CCS should be configured to detect fault conditions (e.g. open loop, over/under range value, and transmitter self-diagnostic faults) and issue the CCS to BMS trip signal upon fault detection.

NOTE 2 To maintain safety integrity and availability, site policy may prohibit the CCS from initiating a trip to the BMS. Thus, when a CCS to BMS trip is recommended by the burner manufacturer (e.g. in accordance with ABMA 307), special approval may be required.

Monitoring O_2 and CO in the combustion flue gas can also prove useful for optimizing combustion efficiency and detecting deviations from optimum conditions. While acceptable for process control, these devices are not recommended for use as part of a CCS trip due to slow response of the overall system and the difficulty in achieving a representative sample. For example, an in situ O_2 sensor has a typical response time of 10 s. An in situ combustibles analyzer has a typical response time of 20 s to 30 s. Laser based technology for O_2 and CO has a sensor response of 5 s. The typical sample location for flue gas analyzer(s) is between the combustion chamber outlet and the economizer. This can make analytical instruments unsuitable for a CCS trip. For example, if the transport time for a step change in air/fuel ratio at the burner(s) to the analyzer's sample location is 15 s to 30 s, the analytical measurements cannot respond within the typical process safety time of 5 s to 10 s at operating conditions.

7.2.3.15 Timing Sequences

NFPA 85 Interpretation and API 538 guidance for timing sequences is as follows.

a) NFPA 85 Interpretation—For both single and multiple burner boilers NFPA 85 establishes a maximum TFI period for both igniter and main burner flames. For single burners, a 10 s TFI period is specified. For multiple burners, a 5 s TFI period is specified. The basis for the different TFI periods is not provided.

   For single burner boilers, a maximum FFRT of 4 s is specified, as is a maximum SSV closing time of 1 s following de-energization of the valves. For multiple burner boilers, no maximum FFRT or valve closing time is specified.

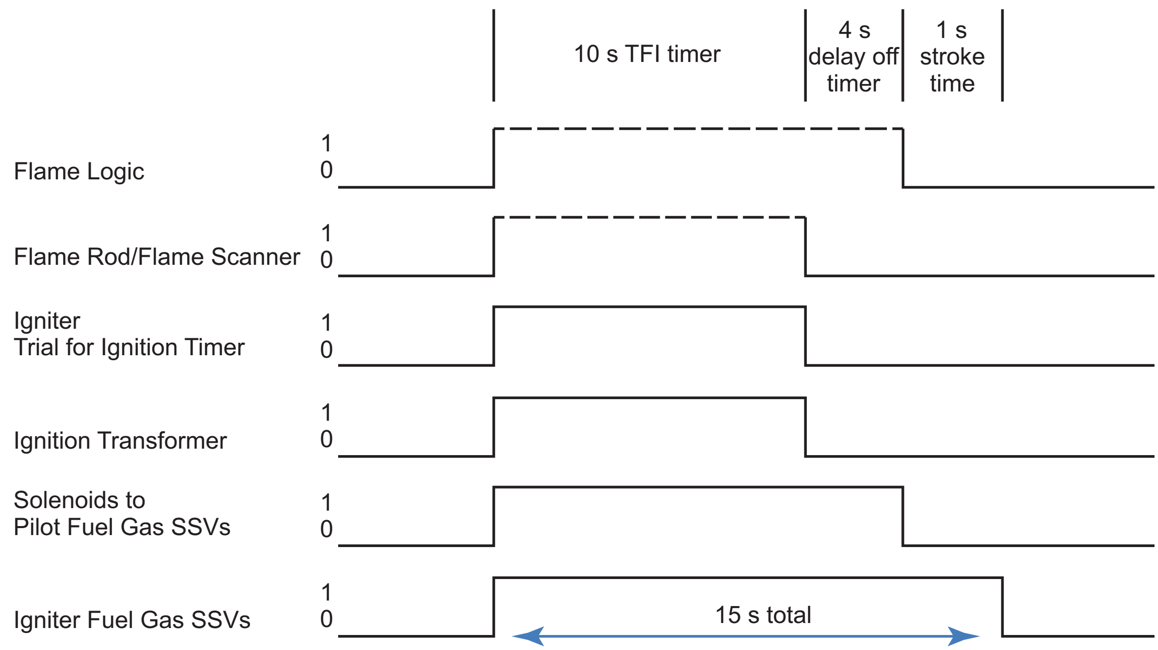
   In addition, unlike NFPA 86 (*Standard for Ovens and Furnaces*), no criteria is provided for extended TFI periods. In NFPA 86 an extended TFI period for gaseous fuels is allowed, provided the change is formally approved by the AHJ and it is shown that 25 % of the LEL cannot be exceeded during the extended time.

b) API 538 Guidance—Within the refining and petrochemical industry there has been inconsistent interpretation of the TFI period due to the scanner delay off timer associated with proof of flame. Some apply the TFI period to the duration of spark, as shown below in Example 1.

   Others reduce the TFI period to ensure the igniter fuel gas SSVs are open for no longer than 10 s, as shown in Example 2.

   From a process safety perspective, either model is acceptable since the amount of unburned fuel gas entering the combustion chamber during the igniter TFI period is negligible (i.e. well below 25 % of the LEL).

   For single burner boilers, the design intent is to close the main fuel gas SSVs if main flame is not proven within 10 s. Therefore, the TFI period should be targeted at 5 s (e.g. similar to Example 2), unless field testing



Example 1

Spark is present for the duration the 10 s TFI timer. If there has been no flame detected during the TFI period, the SSV solenoids will be de-energized at the end of the TFI period. However, if an unstable flame has flickered off as the ignition source is removed at the end of the TFI period (as shown here), the scanner will not indicate loss of flame until the end of the delay timer. Therefore, the igniter fuel gas SSVs may be open as long as 15 s.

demonstrates that a longer TFI period (e.g. up to 10 s) is required to establish a stable flame. This reduces the potential for an unstable flame (e.g. loss of flame just prior to the end of the TFI period) to cause the logic to hold the SSVs open as long as 15 s (e.g. similar to Example 1 with the igniter flame as the ignition source). Additionally, the concentration of unburned fuel gas should not exceed 25 % of the LEL (see 7.5.5.2.2) during the light-off sequence.

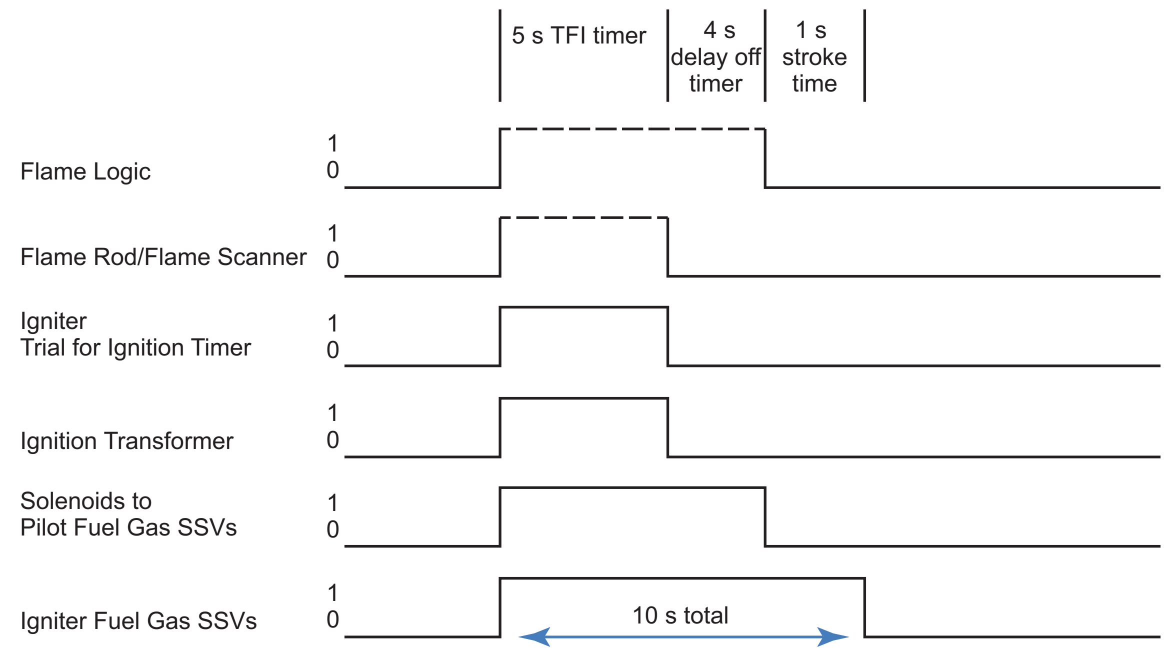
For multiple burner boilers, except where Class 1 igniters are in service, a MFT is initiated if the first burner's flame is not proven within 5 s after the main fuel actually begins to enter the furnace. For the following burner and all subsequent burners placed in operation, fuel flow to that burner(s) is stopped if flame is not proven within 5 s after the main fuel actually begins to enter the furnace. The concentration of unburned fuel gas should not exceed 25 % of the LEL during the light-off sequence.

NOTE When applying 25 % LEL rule for multiple burner boilers, a consideration is to divide the total firebox volume by the number of burners. This simplified approach reduces the likelihood of creating fuel-rich conditions at any localized zone within the boiler.

It is important to note that adjustment of TFI timers alone does not ensure safe light-off of main burner(s). Operator error or equipment malfunction during the TFI period may allow the fuel gas control valve to move well beyond prescribed light-off conditions creating a fuel-rich, hazardous gas mixture within the combustion chamber. Therefore, it is recommended to limit the amount of unburned fuel gas entering the combustion chamber during the light-off sequence via:

1) BMS supervision of light-off conditions (see 7.2.3.10);

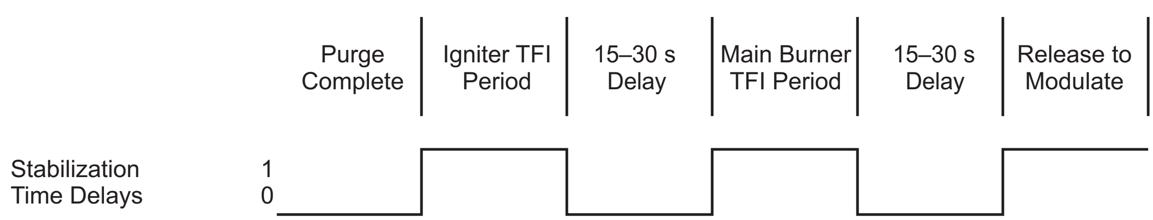
2) restricting control valve movement until release-to-modulate (see 7.2.3.10).



Example 2

Spark is present for the duration the 5 s TFI timer. If there has been no flame detected during the TFI period, the SSV solenoids will be de-energized at the end of the TFI period. However, if an unstable flame has flickered off as the ignition source is removed at the end of the TFI period (as shown here), the scanner will not indicate loss of flame until the end of the delay timer. Therefore, the igniter fuel gas SSVs may be open as long as 10 s.

An additional consideration is to include stabilization time between individual stages of the light-off sequence to permit the combustion chamber to equalize to steady state conditions as shown below in Example 3.



Example 3

Stabilization time is recommended between proof of igniter flame and main burner start, and proof of main flame(s) and release-to-modulate.

7.2.3.16 Flame Failure Response Time vs Safety Shutoff Valve Stroke Time—Time to Safe State

NFPA 85 Interpretation and API 538 guidance for flame failure response time vs safety shutoff valve stroke time—time to safe state is as follows.

a) NFPA 85 Interpretation—For single burner boilers, the response time from flame failure to de-energization of the SSVs shall not exceed 4 s. The response time from de-energization of the SSVs to full closure shall not exceed 1 s.

   For multiple burner boilers, response times are not prescribed from flame failure to de-energization of the SSVs or from de-energization of the SSVs to full closure.

b) API 538 Guidance—As a design target, the SSVs to a burner should be fully closed within 5 s of detecting flame failure. For loss of flame, time to safe state (see 7.5.3.6) includes the FFRT and the stroke time to close the SSVs.

1) FFRT—The time interval from flame failure to de-energization of the SSVs includes a configurable FFRT in the flame scanner and may include a configurable delay trip timer in the logic solver.

— Flame Scanner—The FFRT in the flame scanner is typically configurable from 1 s to 4 s (i.e. the upper value is limited by local code requirements). Configuring the minimum FFRT (e.g. 1 s) in the scanner may increase nuisance trips. When a delay trip timer is configured in the logic solver, configuring the minimum FFRT in the scanner may cause high frequency cycling of the flame relay (i.e. dry contact) to the logic solver. Therefore, to reduce the likelihood of nuisance trips or alarms due to flame flicker (i.e. a momentary reduction in flame strength within the scanner's line of sight with no actual loss of flame), the FFRT in the scanner may be extended (e.g. 2 s to 3 s).

— Logic Solver—While a delay trip timer of 0 s in the logic solver is frequently inferred, a minimal delay trip timer (e.g. 250 ms) may be configured to mitigate transient states within the program.

— Advisory—Where a delay trip timer is configured in the logic solver, the sum of the FFRT in the scanner and the logic solver should not exceed the specified maximum FFRT.

2) SSV Stroke Time—Within the refining and petrochemical industry, a stroke time limit of 1 s to close the SSVs is frequently unachievable due to the size of the valve/actuator combination. A stroke time of 2 s to 3 s is more typical. To expedite valve closure time, it is recommended to specify larger actuator connections ($\geq ^1/_2$ in. NPT) and quick exhaust valves ($\geq ^1/_2$ in. orifice). Reducing the air supply pressure to the actuators (to no higher than required) will reduce the compressed volumes in the actuator, subsequently reducing the air exhaust time.

As an example, suppose the best achievable SSV stroke time is approximately 2 s. To achieve the design target of 5 s to safe state, the maximum FFRT may be reduced from 4 s to increase the permissible valve stroke time as shown:

i) total FFRT for loss of flame $\approx$ 3 s (combined FFRT in the scanner and logic solver),

ii) stroke time to close the SSVs $\approx$ 2 s.

Suppose the SSV stroke time (e.g. 6 in. to 8 in. ball valve) cannot be reduced below 3 s to 4 s. Combined with a minimum FFRT of 2 s to 3 s, this would yield a safe state time of 5 s to 7 s, which is beyond the design target of 5 s. In this case, a design consideration is to install a BMS solenoid on the fuel gas control valve (e.g. a rising stem globe valve). Since a globe valve has a faster stroke time than a ball valve, safe state can be achieved more quickly. Ultimately, the design objective is to achieve safe state within the available process safety time.

7.3 Process Measurement

7.3.1 General

A competent designer shall ensure that boiler instrumentation is properly selected and applied for the application and that all instruments have the required certifications (e.g. FM, CSA, UL, or IEC).

Instrumentation should consider accessibility for efficient maintenance and for good operation. Flow elements, control valves, transmitters, thermowells, level gauges, and local controllers, as well as analyzer sample points, generally should be readily accessible from grade or from permanent platforms or fixed ladders. In this document, special consideration is given to the location, accessibility, and readability of the elements. Refer to API 551 for installation details.

7.3.2 Temperature

7.3.2.1 General

Continuous temperature measurement in boiler applications generally uses thermocouples or resistance temperature detectors (RTDs). Thermocouples may be selected for speed of response. RTDs may be selected for accuracy.

See API 551 for thermowell and skin couple design guidelines.

7.3.2.2 Furnace Exit Gas Temperature

FEGT is the temperature of the flue gas leaving the combustion chamber. Although not typical for the industry, this temperature may be used for start-up and historical trending purposes. Highly accurate temperature measurement here is not necessary for normal refinery boiler service.

a) A sample port next to the thermowell location is recommended to allow temperature verification.

b) Thermowell materials must be suitable for the furnace temperatures and atmosphere. American Iron and Steel Institute (AISI) Types 446 and 347 stainless steels are generally acceptable materials. For some severe services, 310 stainless steel, Inconel, ceramic, or ceramic-coated thermowells have been used.

7.3.2.3 Superheater, Generating Bank, and Economizer Flue Gas Temperature

Flue gas temperature measurement within the superheater, steam generation boiler bank, and economizer may be useful to assess performance of these services. Flue gas thermocouples may cross-check their heat absorbed duties.

To facilitate testing/evaluation, nozzles for flue gas temperature measurement should be provided.

7.3.2.4 Stack Temperature

Stack temperature measurement may be used as one of several indications that the boiler is operating within its designed operating envelope. When combined with percent oxygen measurement in flue gas, stack temperature may be used as an indication of efficiency. Considerations include the following.

a) A thermocouple in a thermowell should be installed in the stack to measure the temperature of the flue gas.

   1) If a common stack is used with several boilers, each boiler should have a temperature measurement in the ducting to the common stack. The common stack should still have a temperature measurement point to monitor boiler efficiency and environmental performance.

   2) When a boiler has multiple ducts to a common stack, temperature measurement in each duct should be considered.

b) The stack temperature measuring device should be located near enough to the entrance of the stack so external heat losses will not have reduced the flue gas temperature. The device should be placed with sufficient distance that from the entrance of the stack (e.g. five stack diameters or more) to allow the flow to be fully mixed and developed.

c) Avoid installing a temperature measurement point in stagnant areas where flue gas is not flowing, which may give a misleading reading.

   1) The tip of the thermowell should extend a minimum of 152 mm (6 in.) off the inner wall.

   2) Right angle flue gas flow across the thermowell is recommended.

For units with external FGR to the fan inlet, stack temperature should be monitored to reduce the likelihood of developing hoar frost on FD fan blades. When the stack temperature drops, too much FGR may compromise the ability of an APH upstream of the FD fan to keep the combustion air and FGR mixture above the dew point throughout the unit operating range.

7.3.2.5 Water and Steam Inlet and Outlet Temperatures

Boilers should have temperature measurements on the superheater outlet, upstream and downstream of desuperheaters, and economizer inlet and outlet headers as needed for operator guidance and control and to ensure temperatures remain within operating limits for safe operation of the boiler.

7.3.2.6 Tube Skin Thermocouples

Tube skin thermocouples are used to monitor superheater coil temperature and steam temperature within individual coils. When used to monitor steam temperature in individual steam coils, the thermocouple is mounted on the tube outside the flue gas path. Such thermocouples may be used to monitor temperature deviation in the superheater across the width of the furnace and to ensure all condensate is removed from non-drainable superheaters during a normal start-up. When used to measure superheater coil metal temperature in the flue gas, such thermocouples may have a relatively short functional life and are typically only used for start-up and/or testing purposes.

a) The placement of tube skin thermocouples should be done in conjunction with a boiler specialist experienced with the specific application.

b) The thermocouple and leads must be able to withstand the severe environment within the boiler. To achieve a satisfactory length of service, consider the use of a sheath material with a high temperature resistance.

c) Protection of the thermocouple element from the flame, as well as the corrosive flue gas, may be achieved through proper use of shielding, lead wire temperature rating, and routing. The design should accommodate superheater and economizer tube expansion. The sheath material should resist both corrosion and embrittlement.

d) The skin thermocouple assembly should be in direct contact with the tube. Any gap between the tube and the thermocouple attachment will cause an erroneous reading. Manufacturer's installation procedures are very important to follow to ensure proper operation of the thermocouple. While an ungrounded junction offers electrical isolation (i.e. avoids ground loops), a grounded junction may be used when accuracy and faster response is required.

7.3.2.7 Fuel Gas Temperature

Fuel gas temperature may be used to improve the accuracy of volume flow measurement. For example, if a differential pressure flow measurement has been designed for a temperature of 38 °C (100 °F) and the fuel gas temperature decreases to 16 °C (60 °F), the actual flow will increase from that indicated by approximately 4 %.

7.3.2.8 Combustion Air Preheater Temperatures

When a steam or condensate combustion air preheater is used, air temperature measurements are required downstream of the preheater coils and downstream of the air bypass.

When a flue gas combustion air preheater is used, multiple temperature measurements may be used to evaluate and monitor preheater performance. These should be located at the following points.

a) Flue gas inlet to combustion air preheater.

b) ID fan inlet.

c) Air temperature to the combustion air preheater (ambient reading is sufficient if the combustion air is not heated prior to the combustion air preheater).

d) Air temperature exiting the combustion air preheater.

e) Combustion air to burners.

f) For stationary exchangers without a glass section, provide multiple skin thermocouples on the flue gas side outlet near the air inlet to measure metal surface temperature. For rotary exchangers, minimum metal temperature must be inferred from the combustion air inlet temperature and the flue gas exit temperature. During operation, combustion air may be bypassed around the combustion air preheater as needed to maintain the metal surface temperature above the acid dew point.

g) For stationary exchangers with a glass section, install a thermowell between the metal and glass section. This temperature measurement is used to ensure temperature of flue gas entering the glass section is below the design temperature of the elastomer being used to protect the tube sheets and ferrules in the glass section.

7.3.3 Pressure

7.3.3.1 General

The pressure taps for instrumentation used for control and shutdown should be independent. To ensure measurement accuracy, match the transmitter cell range to the measurement range as closely as possible.

It is generally recommended that the trip set point is not below the minimum span of the transmitter's sensor range. A higher range than required for the application may not have the desired sensitivity at the target trip set point. See Table 11 for examples of pressure sensors.

NOTE For the sample transmitters shown in Table 11, the general turndown specifications (e.g. a nominal turndown of 200:1 or 100:1 may not universally apply to the minimum span for all sensor ranges.

Table 11—Pressure Sensors (Examples) [a]

Example Differential Pressure Sensors (USC Units)			
Sensor Range	Minimum Span		URL Upper Range Limit
	Nominal Turndown 200:1	Nominal Turndown 100:1	
0	0.1 in. H_2O (0.25 mbar)	0.1 in. H_2O (0.25 mbar)	3.0 in. H_2O (7.5 mbar)
1	0.5 in. H_2O (1.24 mbar)	0.5 in. H_2O (1.24 mbar)	25 in. H_2O (62.3 mbar)
2	1.3 in. H_2O (3.11 mbar)	2.5 in. H_2O (6.23 mbar)	250 in. H_2O (0.62 bar)
Example Differential Pressure Sensors (USC Units)			
Sensor Range	Minimum Span		URL Upper Range Limit
	Nominal Turndown 200:1	Nominal Turndown 100:1	
1	0.3 psig (20.7 mbar)	0.3 psig (20.7 mbar)	30 psig (2.07 bar)
2	0.75 psig (51.7 mbar)	1.5 psig (0.103 bar)	150 psig (10.34 bar)
5	1000 psig (68.9 bar)	2000 psig (137.9 bar)	10,000 psig (689.5 bar)

[a] Rosemount 3051S, Product Data Sheet 00813-0100-4801, Rev KA, Catalog 2008–2009.

7.3.3.2 Steam Drum Pressure

In steam service, impulse lines should be filled with water to prevent live steam from contacting the transmitter's diaphragm. See API 551 for design details.

7.3.3.3 Combustion Air Pressure

In general, combustion air pressure is measured at the following locations:

a) inlet of the fan using a gauge,

b) outlet of the fan using a gauge, and

c) downstream of all combustion air dampers using a transmitter.

Direct air flow measurement is the preferred method for proving air flow (see 7.3.4.5). However, where air pressure is used to prove airflow, the pressure transmitter should be located downstream of control dampers and preheaters, but far enough upstream of the burners so that combustion air pressure at the measurement point will yield sufficiently high pressure even at turndown combustion air flow rates. The basis is to prevent a tap location upstream of a damper that has malfunction closed from incorrectly indicating high combustion air flow due to high backpressure. Downstream of preheaters removes the effect of fouling from set point resolution.

The recommended location for combustion air pressure is typically at the smallest cross-sectional area of the inlet air plenum downstream of control dampers and the preheater that yields the highest static pressure. Depending upon the size of duct, however, the pressure at the desired trip set point may be very low, which could increase the risk of nuisance trips on low combustion air flow. Alternatively, place the transmitter upstream of the combustion air damper with a minimum flow mechanical stop on the damper set for minimum air flow requirements.

A frequent consideration is to use differential pressure along a section of air ducting to correlate pressure drop with air flow. Since increased velocities produce a higher pressure drop, a higher velocity will yield a higher differential pressure and a lower velocity will yield a lower differential pressure. To approximate a linear flow characteristic, this technique is most effective with straight runs of duct that have an equal pressure drop per unit of length. This section of air duct must be free of any dampers, perforated plate or bird screen that could eventually block and create a false reading.

7.3.3.4 Flue Gas Pressure

7.3.3.4.1 General

Flue gas pressure sensing lines shall be arranged so that water condensate will naturally return into the sampled flue gas source. In addition, drip legs with dual isolation valves should be supplied to allow periodic purging of the sampling line without affecting the operation.

7.3.3.4.2 Flue Gas Pressure Upstream and Downstream of an ID Fan

In general, flue gas pressure is measured in flue gas ducts at the following locations:

a) inlet of the ID fan using a transmitter,

b) outlet of the ID fan using a gauge.

7.3.3.4.3 Flue Gas Pressure Upstream and Downstream of Combustions Air Preheat Systems

To aid in the evaluation of a combustion air preheater's performance, pressure taps should be located at the inlet and outlet of the air and flue gas sides of the exchanger. A differential pressure gauge or transmitter may be used across the flue gas side to detect fouling or plugging.

7.3.3.5 Fuel Gas Pressure

Fuel gas pressure may be used to improve the accuracy of volume flow measurement. For example, if a differential pressure flow measurement has been designed for a pressure of 345 kPa (50 psig) and the fuel gas pressure increases to 379 kPa (55 psig), the actual flow will increase from that indicated by approximately 4 %.

Fuel gas supply pressure should be measured upstream of the fuel gas control valves and downstream of the fuel gas preparation system. Where pressure compensation is used, pressure measurement should be located close to the fuel gas flow measurement device.

Fuel gas burner pressure should be measured downstream of the fuel gas control valve. The piping pressure drop from the pressure measurement point to the burner should be designed for no more than $^{1}/_{2}$ psi at maximum heat release for all anticipated fuel gas compositions. It is generally recommended that a trip set point not be below the minimum span of the transmitter cell range. Thus, separate transmitters to measure the low and high alarm and trip points may be required depending upon the cell range selected and the turndown capability of the transmitter.

7.3.4 Flow

7.3.4.1 Turndown Requirement

Turndown of the combustion air and fuel flow measurements and final control elements (e.g. control valves and dampers) should exceed the burner(s) turndown by 1.5 to 2 times. For example, a 4:1 turndown burner may be well controlled with an orifice flow meter designed for a 6:1 flow turndown. However, a 10:1 turndown burner may require higher turndown in flow measurement. For example, a coriolis meter is capable of a 50:1 turndown.

When using a differential pressure flow measurement, the span should be selected to meet the turndown requirements of the application. By assigning a default value for span (e.g. 100 in. WC), the desired flow turndown may not be achieved. Since deadweight testers are no longer used to calibrate transmitters, it is no longer recommended to target a default span of 100 in. WC for all applications. For example, if a calibrated span of 100 in. WC is used with a sensor range of 250 in., the turndown of the flow measurement will be reduced to approximately 6:1 instead of the 10:1 it would have been if the span had been set at 250 in. WC with a beta ratio between $0.2 < \beta < 0.7$. While an orifice meter with a 6:1 flow turndown would be sufficient for a burner with 4:1 turndown, it would not be recommended for an ultralow NOx burner with 10:1 turndown. Options would include increasing the span to improve the orifice flow turndown or using a different flow element with better turndown. See the example calculation below.

Flow ≈ k * sqrt (DP)		
Flow (%)	**k**	**DP**
100.00	6.32	250.00
63.25	6.32	100.00
10.00	6.32	2.50

Assume 250 in. of span with a sensor upper range limit (URL) of 250 in. and a minimum span of 2.5 in. Using the full 100:1 turndown capability of the transmitter yields 10:1 flow turndown. This example is intended to demonstrate that using 100 in. of differential for the span would use only 63 % of the available 10:1 flow turndown, subsequently reducing the actual flow turndown to ~6:1.

Flow ≈ k * sqrt (DP)		
Flow (%)	**k**	**DP**
100.00	10.00	100.00
15.81	10.00	2.50
10.00	10.00	1.00

Assume 100 in. of span with a sensor URL of 250 in. and a minimum span of 2.5 in. Note that the flow turndown is 100/15.81 ≈ 6:1. This example is intended to demonstrate that 10 % of flow will fall below the minimum span of the transmitter. Thus, 10:1 flow turndown is not achieved. In fact, flow measurement below 15 % of upper range value (URV) will have less accuracy due to the turndown limits of the transmitter.

7.3.4.2 Fuel Gas Flow

7.3.4.2.1 General

The type of fuel gas flow measurement should be selected based upon turndown requirements and the anticipated variability in fuel gas composition. Depending upon the amount and rate of change in fuel gas composition and the subsequent change in air demand at the burner(s), either volume flow or mass flow may be selected.

7.3.4.2.2 Volume Flow vs Mass Flow

Fuel gas flow may be reported in volumetric flow units (orifice plate meter) or mass flow units (coriolis meter). Both readings may be converted to rate of heat release units.

a) With a negligible change in the amount of inert gases or hydrogen, the heating value may be inferred from fuel gas SG. Analyzers are available to measure the flowing density and compensate for the temperature and pressure of the sample to determine SG (see 7.3.5).

b) With varying amount of inert compounds (such as carbon dioxide or nitrogen) or where large step changes in fuel gas composition may adversely impact combustion control, the heating value may be directly measured (see 7.3.5).

When fuel gas composition is expected to change significantly (e.g. refinery fuel gas), and a fuel gas density or heating value analyzer is not available to compensate volume flow, mass flow may be an important consideration since heating value correlates more closely to mass flow than volume flow (see Table 12). In practice, this is important when a change in fuel gas composition yields an increase in air demand. When the air demand exceeds the combustion air available, there is an increased risk of driving the burner(s) into substoichiometric combustion. Thus, when the fuel gas composition is expected to change significantly, mass flow or density corrected volume flow (see 7.3.4.2.2) improves the capability of the CCS to maintain sufficient combustion air to the burner(s).

Table 12—Gross Heating Values of Fuel Gas Compounds

Compound		Mass Flow Basis			Volume Flow Basis		
		BTU/lb	KJ/kg	% Δ from CH_4	BTU/scf	KJ/Nm^3	%Δ from CH_4
Methane	CH_4	23,887	55,561	—	1012	37,706	—
Ethane	C_2H_6	22,323	51,923	–7 %	1772	66,023	75 %
Propane	C_3H_8	21,669	50,402	–9 %	2522	93,967	149 %
I-Butane	C_4H_{10}	21,186	49,279	–11 %	3251	121,129	221 %
n-Butane	C_4H_{10}	21,313	49,574	–11 %	3270	121,837	223 %
I-Pentane	C_5H_{12}	21,064	48,995	–12 %	4012	149,483	297 %
n-Pentane	C_5H_{12}	21,105	49,090	–12 %	4020	149,781	297 %
(n)Hexane+	C_6H_{14}	20,804	48,390	–13 %	4733	176,347	368 %
Hydrogen	H_2	51,900	120,719	117 %	273	10,172	–73%

While mass flow will maintain sufficient combustion air to the burner(s) for the vast majority of applications, a few cases may require additional analysis (e.g. a large step change in hydrogen concentration when firing refinery fuel gas). For slow changes in fuel gas composition (e.g. >5 min), a heating value analyzer may provide feedback to the CCS. However, for rapid changes in fuel gas composition (e.g. <5 min), a heating value analyzer may have insufficient response time. In these cases, the safety margin may be achieved with excess air by increasing the normal operating %O_2 set point.

7.3.4.2.3 Orifice Plate Meter

An orifice flow meter should be installed in the main fuel line located downstream of the fuel gas header pressure controller and upstream of the fuel gas control valve where the pressure is relatively constant. A straight run of upstream and downstream piping is required for an orifice plate. For details on orifice plates, refer to API *MPMS* Ch. 14.3.1.

If the fuel gas composition is relatively constant (e.g. natural gas) with minimal variability in fuel gas header pressure and temperature from base conditions, an uncompensated volume flow measurement is typically sufficient to meet process control (combustion air) requirements.

However, when a change in fuel gas conditions at the burner(s) creates an increasing air demand that exceeds the combustion air available, there is an increased risk of driving the burner(s) into substoichiometric combustion. When this occurs, it is important to identify the primary source of the variability:

a) a change in fuel gas composition,

b) a change in fuel gas header pressure and temperature.

If the fuel gas composition and/or the fuel gas density (via a change in header pressure and temperature) are expected to change significantly, an orifice flow meter may be SG compensated with a fuel gas density analyzer to accurately indicate volume flow. The SG compensated volume flow may be multiplied by the measured density (reported as SG) to achieve mass flow.

$$\text{SG compensated volume flow} = \text{volume flow (uncompensated)} \times \sqrt{\frac{\text{SG(design)}}{\text{SG(actual)}}}$$

$$\text{mass flow} = \text{SG compensated volume flow} \times \text{measured density}$$

If the fuel gas composition is relatively constant (e.g. natural gas), but the fuel gas header pressure and temperature are expected to change significantly, an orifice flow meter may be pressure and temperature compensated (after converting to absolute units) to accurately indicate volume flow.

$$\text{P and T compensated volume flow} = \text{volume flow (uncompensated)} \times \sqrt{\frac{P(\text{actual})}{P(\text{design})} \times \frac{T(\text{design})}{T(\text{actual})}}$$

7.3.4.2.4 Coriolis Meter

A coriolis flow meter should be installed upstream of the fuel gas control valve. While coriolis meters do not require the straight runs of piping (i.e. meter runs) of an orifice plate, the manufacturer should be consulted regarding specific recommendations on upstream piping.

Coriolis meters measure mass flow directly and do not require pressure, temperature, or SG compensation for accurate mass flow reporting. Therefore, for the vast majority of applications where the fuel gas composition is expected to change significantly (see 7.3.4.2.1), a coriolis mass flow meter improves the capability of the CCS to maintain sufficient combustion air to the burner(s).

A potential advantage with a coriolis meter over SG compensated volume flow (see 7.3.4.2.2) is the speed of response to a change in fuel gas composition. With a coriolis meter, there is no additional delay associated with displacing the internal volume of sample system and analytical components (see 7.3.5). However, to improve reliability, the user must ensure that the coriolis tube metallurgy selected will resist the corrosive components in refinery fuel gas and that any solids that may precipitate out of refinery fuel gas into the vibrating tubes will not adversely impact meter operation.

It is important to note that a coriolis meter is not a fuel gas density analyzer. Mass flow is measured by detecting the force exerted on the vibrating tube(s) inside the meter as a result of changing the direction of the momentum vector. The force twists the tubes and shifts the phase of the sine wave at the detection point. The actual measurement is the degree of phase shift in the vibrating tubes. While it is possible to measure the energy input required for the tube(s) in a coriolis meter to vibrate at their natural frequency, and from this measurement estimate the mass contained inside the known tube volume, it is not recommended to use this measurement to estimate fuel gas density and then infer heating value. When dealing with liquids, a plot of density vs natural frequency of different fluids is well characterized by a straight line. However, data scatter is a concern in the gas region of the plot. For this reason, the density output option is typically disabled in fuel gas service.

Since the density output from a coriolis meter is typically disabled in fuel gas service, a coriolis meter requires the use of mass flow units (e.g. PPH) or the installation of a gas density analyzer for conversion to volume flow units (e.g. SCFH). A typical sensor response time for a gas density analyzer (vibration type, resonant frequency) is 5 s to 90 % response or <30 s including the time to displace the internal volume of all components in the sample loop.

7.3.4.2.5 Thermal Mass Fuel Flow

Thermal mass flow sensors work well with clean, dry gas. However, high moisture content in the fuel gas may present reliability issues. Liquid droplets may cause the sensor RTD to lose heat rapidly (cooling effect) affecting the velocity/flow reading. As a result, the flow indication may spike (malfunction high) and return to normal once the moisture evaporates. This is an important consideration for low NOx burners where air/fuel ratio is controlled over a narrow operating range.

For process control applications, constant temperature anemometers are recommended since they have a response time <5 s. Constant power anemometers are approximately 5 s to 10 s slower.

7.3.4.3 Fuel Oil Flow

A fuel oil flow meter should be installed downstream of the regulator and upstream of the fuel flow control valve.

Orifice flow meters may be used for light fuel oil systems. However, the typical square-edged concentric orifice plate may not be well suited to large swings in oil viscosity. Recommended practice for measuring heavy fuel oil is to use either a quadrant orifice plate or a coriolis meter. A coriolis meter is also recommended where a density measurement is desired. When dealing with liquids, a plot of density vs natural frequency for different fluids is well characterized by a straight line.

7.3.4.4 Boiler Feedwater Flow

Flow measurement shall be located upstream of the economizer coil (or steam drum inlet if an economizer is not present).

7.3.4.5 Combustion Air Flow

7.3.4.5.1 General

Air flow measurement is used for metered flow to the CCS and is critical to the boiler’s safety and performance.

Temperature compensation is typically added to a differential pressure air flow measurement when combustion air temperature varies by more than 28 °C (50 °F) from design temperature. For example, if a differential pressure flow measurement has been designed for a temperature of 16 °C (60 °F) and the combustion air temperature increases to 43 °C (110 °F), the actual flow will decrease from that indicated by approximately 4 %.

Due to minimal variability in combustion air pressure, pressure compensation is not typically required for combustion air flow. Instead, design pressure is typically specified as the normal operating pressure at the air flow element.

Direct or inferred methods are as follows.

a) Flow elements are located in the FD ducting system using venturi, averaging pitot tubes, or thermal mass devices. Proper straight run of air duct without obstructions (e.g. flow dampers) will improve accuracy and the quality of air flow measurements. For applications with insufficient straight run of duct, multi-point thermal mass arrays may yield significant improvement to measurement accuracy and turndown. Averaging flow elements, flow rings or grids can also have applicability in measuring air flow in short ducts.

b) Inferred air flow by measuring differential pressure across the flue gas side from combustion windbox to economizer outlet is another option; however, careful consideration should be given to possible external tube side fouling or sootblower effect. In general, this method is less common than direct air flow measurement and should be avoided whenever possible due to reliability and safety concerns.

7.3.4.5.2 Thermal Mass Air Flow

Thermal mass flow meters have a high turndown capability. Multi-point thermal mass arrays can be a consideration for difficult air flow applications, due to their improved capability to average highly stratified flows in large ducts with large changes in velocity profiles. However, external factors, such as the accumulation of dust or oil mist on the sensors, may present sensor reading reliability issues. Therefore, easy access to retractable probes is an important design consideration to facilitate periodic sensor cleaning.

a) A thermal mass air flow meter may malfunction low with dust accumulation. As the dust/dirt builds up on the sensor RTD (insulating effect) the heat loss due to gas velocity and density will decrease. When this occurs, the velocity/flow rate reading will trend downward as the dust/dirt build up increases.

b) A thermal mass air flow meter may malfunction low should an oil film (insulating effect) be permitted coat the sensor RTD. For example, a FD fan bearing with an external oiler that consumes a large amount of oil (e.g. a quart a day) will pass an oil mist into the combustion air flow stream, causing the thermal mass sensors (downstream of the FD fan) to malfunction low. Thus, it is important to verify that fan bearings are in good condition and are not consuming large amounts of oil.

For process control applications, constant temperature anemometers are recommended since they have a response time <5 s. Constant power anemometers are approximately 5 s to 10 s slower.

7.3.5 Fuel Gas Heating Value Analysis

For small variations in fuel gas composition and heating value, oxygen trim control to the air-fuel ratio may be effective.

Where variations in fuel gas composition and heating value is likely to yield substoichiometric combustion, it is recommended to compensate the fuel gas flow measurement (see 7.3.4.2).

With a negligible change in the amount of inert compounds in the fuel gas, a change in heating value may be inferred from a change in fuel gas density (e.g. mass flow measurement or gas density analyzer). When SG compensating volume flow, a typical sensor response time for a gas density analyzer (vibration type, resonant frequency) is 5 s to 90 % response or <30 s including the time to displace the internal volume of all components in the sample loop.

With a varying amount of inert compounds in the fuel gas (e.g. carbon dioxide or nitrogen) and where wide variations in heating value may adversely impact combustion control, a Wobbe index meter or heat of combustion meter is recommended. This measurement is generally made on the plant fuel gas system rather than at individual boilers. Calorimeters and gas chromatographs provide direct analytical measurements for determining the heating value. Gas chromatographs and calorimeters are expensive, complex, and require more maintenance than densitometers; however, density measurements are not suitable for inferring the heating value of the fuel gas when significant and variable concentrations of inert gases are present in the fuel gas.

Wobbe Index—The Wobbe index is the main indicator of the interchangeability of fuel gases and is frequently defined in the specifications of gas supply and transport utilities. Wobbe index is used to compare the combustion energy output with different composition of fuel gases. If two fuels have identical Wobbe indices, then for given pressure and valve settings the energy output will also be identical. The Wobbe index is a critical factor to minimize the impact of fluctuations in your fuel gas supply and can therefore be used to increase combustion efficiency.

$$\text{Wobbe index} = \frac{\text{higher heating value of the fuel gas}}{\sqrt{\text{specific gravity of the fuel gas}}}$$

Combustion Air Requirement Index (CARI)—The required amount of dry air to burn 1 Nm^3 of fuel gas compensated for the SG of the gas.

$$\text{CARI} = \frac{\text{air demand}}{\sqrt{\text{specific gravity of the fuel gas}}}$$

Higher Heating Value (HHV)—The amount of heat evolved by the complete combustion of a unit volume of gas with air, with water condensed.

$$\text{higher heating value} = \text{Wobbe index} \times \sqrt{\text{specific gravity of the fuel gas}}$$

Specific Gravity (SG)—The specific gravity, also known as relative density is the density of gas in relation to the density of air, when both are at the same reference conditions.

$$\text{specific gravity} = \frac{\text{density of the fuel gas}}{\text{density of the air}}$$

Advisory—For fuel gases containing high concentrations of CO and H_2 there is no direct linear relationship between the Wobbe index and CARI. Therefore, for these gases it is important to use both parameters in the control loop. Most important is CARI, as the optimum air fuel ratio is essential in efficient combustion and minimizing emissions. Wobbe index is used for control of energy flow. Minor systematic errors are less important here as energy input can be corrected with feedback control in most control schemes [5].

The measuring principle of the residual oxygen measurement is based on the analysis of the oxygen content in the flue gas after combustion of the sample. A continuous gas sample is mixed with dry air at a precisely maintained constant ratio, which depends on the Btu range of the gas to be measured. The fuel air mixture in a combustion furnace in the presence of a catalyst at 800 °C, and the oxygen concentration of the combusted sample is measured by a zirconium oxide cell (sensor response <5 s). The residual oxygen provides an accurate measurement for the combustion air requirement of the sample gas, which can be correlated accurately to the Wobbe index of the gas [6].

Typical fuel gas heating value analysis response times are as follows.

a) Heating Value Analyzer (Residual Oxygen Measurement)—approximately 2 min to 90 % response, including the time to displace the volume of all internal components (e.g. fuel gas density analyzer).

b) Gas Chromatographs—3 min. to 5 min.

7.3.6 Flue Gas Analyzers

7.3.6.1 General

For specific analyzer type selection and installation practices, refer to API 555 and local regulatory requirements.

Flue gas analyzers are used to optimize combustion efficiency and monitor atmospheric emissions. These two functions are typically independent and have a different measurement basis (e.g. wet or dry), accuracy, response time, and maintenance requirement. Identification of the measured components and selection of the sample locations are determined by process control regulatory requirements. Inferential methods may also be an acceptable technique to meet these requirements, subject to regulatory approval.

The number of analyzers and sample locations are based upon many considerations including boiler type, boiler control strategy, and fuel composition. Sampling points for atmospheric emissions should be in the stack.

The location of the sampling point within the flue gas stream is important in obtaining a representative sample. Sample probes should penetrate far enough to ensure the sample taken is representative of the majority of the flue gas.

For stack analyzers, where negative pressure exists, air leakage (tramp air) into the boiler upstream of the sample point may alter the flue gas composition. Sampling points should be selected to minimize this effect in boilers where negative pressure exists.

Periodic verification of analyzer performance is recommended to confirm the ability to satisfy process control and regulatory requirements. To meet these criteria, it is important to note that analyzer vendors may publish sensor response differently. While some publish the quickest response to calibration gas, others publish a more useful response to T63 or T90, i.e. 63 % or 90 % final value to a process step change. Measuring the response time to a process step change (not to calibration gas) is recommended to meet these requirements.

a) Where possible, first isolate the analyzer's response to a process step change. For close-coupled extractive systems, back flow the sample probe or transport tube with instrument air, nitrogen or calibration gas. Once the sensor has stabilized, return the system to normal operation. The response time to return to 90 % final value may be compared against the vendor published response times. This technique isolates response issues associated with the analyzer. For example, a slow response may indicate the eductor, flame arrestors, or sample probe may need to be cleaned or that a sensor needs to be changed.

b) When evaluating the process response time, maintain a safe operating margin above combustibles breakthrough. Care is required, especially during step changes in firing rate, to prevent fuel-rich combustion during analyzer testing. As an example, this may be done via a small step change increase in the air-fuel ratio (with metered air flow to the CCS) while monitoring the corresponding increase in excess air at the O_2 analyzer.

c) Once the analyzer's sensor response has been validated, test the analyzer's process response to a step change in flue gas composition. The objective is to measure the process response, not the control system response in automatic mode. Once the process response time has been determined, a ramp rate may be configured in either the air/fuel ratio or fuel gas controller to ensure that a process step change may be detected within the overall response time of the control loop. A slow response may indicate the sample probe is not sampling from the main body of the flue gas flow pattern because of improper probe length and/or sample location.

Verify regulatory and permit requirements. Regulatory agencies may require a CEMS to measure flue gas constituents corrected to a standard basis (e.g. a dry basis with diluents correction). These measurements may include a combination of NOx, SOx, CO, O_2, opacity, and/or CO_2. Stack sample location is also specified by the regulation. CEMS measurements are typically made by utilizing an extractive analyzer sample conditioning system and must be independent from any analyzers used for control.

7.3.6.2 Oxygen

Note that percent oxygen measurement is a variable that may be used for improving boiler efficiency and maintaining safe boiler operation. Percent excess combustion air should not be confused with percent oxygen measurement.

ZrO_2 sensors are "net oxygen" analyzers, which are impacted by the presence of compounds with oxidation potential such as hydrocarbons, CO, hydrogen, and high concentrations of sulfur dioxide.

a) During combustibles breakthrough, H_2 and CO are typically the largest constituents. The ratio of consumption for H_2 and CO to oxygen at a heated ZrO_2 sensor is approximately 2:1. As an example, a sample with 2000 ppmvd (0.2 %) H_2 and CO has the potential to consume 0.1 % oxygen at the sensor. Likewise, a sample with 10,000 ppmvd (1.0 %) H_2 and CO has the potential to consume 0.5 % oxygen at the sensor. Therefore, at low oxygen levels, it is possible for a high concentrations of H_2 and CO to mask (malfunction low) the true oxygen concentration at the sensor.

b) Upon complete loss of flame, methane may be the largest component. The ratio of consumption of methane to oxygen at a heated ZrO_2 sensor is approximately 1:2. As an example, a sample with 1 % methane has the potential to consume 2 % oxygen at the sensor. Likewise, a sample with 5 % methane has the potential to consume 10 % oxygen at the sensor. Therefore, in a fuel-rich environment, it is possible for a high concentration of methane to mask (malfunction low) the true oxygen concentration at the sensor.

Nitrogen backup to the instrument air system has the potential to create an oxygen analyzer malfunction high. ZrO_2 sensors make their measurement based on the difference in the partial pressure of oxygen between a reference gas and a process sample. Typically the reference gas is ambient air; however, instrument air may be used as it is readily available in most industrial facilities. When instrument air is backed up by nitrogen, a change in the oxygen concentration of the reference gas will occur and false readings will be generated by the analyzer. In the case of an instrument air supply that has been changed to nitrogen, the oxygen concentration derived by the analyzer will be higher than the actual concentration at the sampling location. If all instrument air is completely replaced by nitrogen, the analyzer will read 100 % full scale, which is an obvious fault condition.

An oxygen analyzer with heated ZrO_2 sensor is a potential ignition source during the purge cycle. Mitigation options include flame arrestors, a purge interlock to disconnect sensor power, or reverse flow of close-coupled extractive systems. See 7.6.2 for additional considerations.

For both close-coupled extractive and in situ probe systems, flame arrestors may be specified to prevent flame propagation to flue gas due to ignition of gases by the heated sensor; however, they add lag time (estimated 5 s to 10 s for close-coupled extractive systems and 1 min for in situ probe systems). For close-coupled extractive systems, the additional lag time associated with flame arrestors (i.e. 5 s to 10 s) is acceptable for most boiler control applications. For those applications without flame arrestors, alternate techniques include a purge interlock to disconnect sensor power, or reverse flow (blowback) of instrument air or nitrogen through the extractive sample probe during the purge cycle (see 7.6.2).

For those high temperature ZrO_2 sensors that derive their sensor heating from the flue gas, it is important to note that they do not function properly until the flue gas temperature rises to the point where the ZrO_2 sensor becomes active, typically 538 °C (1000 °F) to 1649 °C (3000 °F). Thus, the impact of reduced firing rates on measurement accuracy must be considered.

Laser based technology for combustion control (oxygen trim to air or air/fuel ratio controller) is a design consideration for applications where a single sample point will not provide a representative sample. It has a response time of ≤5 s and can measure across a combustion chamber up to 30 m (98 ft). It is not an ignition source to flue gas and requires no reference air.

a) Since the line-of-sight laser measurement inherently averages the concentration across the total length of the flue gas path, it will not provide indication of the source of oxygen variability in the flue gas as with the multiple point measurements. However, the "path average" measurement inherently samples a much larger cross section of the flue gas increasing the likelihood of a representative measurement.

b) Laser measurement of oxygen does not require reference air for sensor performance, but purge air is typically required in order to prevent direct contact between the process flue gases and instrument optics, and the resulting damage from soiling and heat.

c) Optical alignment is critical and can shift as the boiler warms up. Thus, alignment should be performed at normal operating temperatures. Some tunable diode laser (TDL) designs have optics designed for long path lengths. The laser beam is diverged providing an increasing diameter as the path length increases; this improves alignment stability and allows alignment to be performed at start-up temperature while maintaining alignment through the full temperature range. This has been field proven at path lengths of up to 30 m.

When oxygen is measured as a regulatory requirement (as a diluent), it is measured independently from analyzers used for process control. This oxygen analyzer is part of the CEMS and utilizes the CEMS sample system and reporting mechanism according to federal, state and local regulations and permit requirements.

7.3.6.3 Combustibles

Combustibles measurement may be used to detect the onset of incomplete combustion. These analyzers are typically manufactured as combination in situ or close-coupled extractive oxygen/combustibles analyzers. Combustibles measurements should be taken as near as possible to the point where combustion is completed.

High levels of combustibles in the flue gas may be an indication of burner tip plugging or improper burner operation. High combustibles may also indicate fuel-rich combustion due to an uncompensated (e.g. pressure, temperature, SG) orifice flow element where the actual fuel flow may be higher than the indicated fuel flow.

Since catalytic bead or hot wire technology requires the presence of oxygen for combustibles detection, some sensors may report lower than actual combustible values at low oxygen concentrations. As the measured oxygen concentration approaches 0 %, some analyzers will automatically (via software) drive the combustibles measurement to full scale. Other analyzers supply the CO and/or combustibles sensor with independently sourced “auxiliary, supplemental, or dilution” air to permit combustibles measurement through the low oxygen condition. Ultimately, the user should ensure a fail-safe mechanism is provided for this hazard scenario to ensure safe boiler operation.

A combustibles analyzer (catalytic bead) will typically detect CO, hydrogen, and other combustibles (excluding methane). Since the methane molecule cracks at a high temperature, detecting methane typically requires a separate sensor. Thus, the term “combustibles” can be easily misinterpreted and subsequently misapplied.

A combustibles analyzer with a heated catalytic sensor is a potential ignition source during the purge cycle. Mitigation options include flame arrestors, a purge interlock to disconnect sensor power, or reverse flow of close-coupled extractive systems. See 7.6.2 for additional considerations.

7.3.6.4 Carbon Monoxide

An infrared or laser based CO measurement may be used when controlling the air/fuel ratio near the CO breakthrough point. In a properly designed system, oxygen control at <1 % is acceptable. However, the final control elements (e.g. stack dampers and combustion air dampers) must have sufficient accuracy, turndown and repeatability to keep the boiler in a safe operating region.

For CO control, infrared or laser based analyzer technology with a minimum sensor response time of ≤ 5 s is recommended although ≤ 1 s is preferred. Although CO is detectable with a typical catalytic bead combustibles sensor, it has a response time of 20 s to 25 s to T90 and is not recommended for process control. Additionally, a typical catalytic bead sensor has poor low-end sensitivity and is unsuitable for combustion control where operation of around 50 ppm CO is required.

When using a laser based technology for CO control, methane and hydrogen will not be detected. Current laser based technology will not simultaneously detect multiple combustibles in a single laser beam. Hydrogen cannot be detected with laser technology. If desired, methane will require an independent measurement.

When using fuel gas with very high concentrations of hydrogen, it is possible to reach hydrogen breakthrough in the flue gas prior to reaching CO breakthrough. Thus, CO specific measurements for use as part of a safety strategy may be ineffective in this case.

7.3.6.5 CEMS Systems

A CO specific measurement is sometimes used to satisfy a regulatory requirement. When CO is measured as a regulatory requirement it is reported on a dry basis and is independent of the analytical measurements for process control. As part of the CEMS, the CO analyzer utilizes the CEMS sample system and reporting mechanism according to federal and state regulations and permit requirements. For CEMS systems, the CO analyzer is based on infrared technology and is unaffected by the presence of other flue gases such as unburned hydrocarbons, CO_2, or hydrogen. Extractive or in situ systems may be used for CO measurement.

Extractive systems require a sample probe, sample line, and sample conditioning system with chillers to remove moisture to provide a dry basis measurement.

An in situ analyzer requires access to the point of insertion.

NOTE If an in situ analyzer is allowed, a satisfactory determination of the stack gas water content must be attained for dry basis correlation, typically by a grab sample and lab analysis during stack testing. For infrared based in situ CEMS systems, moisture content may be measured directly.

7.3.6.6 Sulfur Oxides (SOx)

Sulfur oxide analyzers, specifically sulfur dioxide measurement, may be required by regulatory agencies. With a common fuel gas header, sulfur in the fuel gas is typically measured at the fuel gas drum outlet with associated flow measurements as an alternative to installing analyzers on every stack.

If stack emission monitoring is required by the regulatory agency, the type of analyzer is dependent upon the agency's requirements. Monitoring and reporting SOx on a dry basis is achieved by the use of an extractive sample conditioning system to remove the water component. Extractive type is preferred to remove as much moisture as possible, due to the solubility of low SO_2 concentrations in the water.

NOTE If an in situ SOx analyzer is allowed, a satisfactory determination of the stack gas water content must be attained for dry basis correlation, typically by a grab sample and lab analysis during stack testing. The majority of SOx analyzers used in flue gas analysis are based upon ultraviolet (UV) or IR technology.

7.3.6.7 Nitrogen Oxides (NOx)

NOx measurement is often required by regulatory agencies.

If stack emission monitoring is required by the regulatory agency, the type of analyzer is dependent upon the conditions of the agency. Monitoring and reporting NOx on a dry basis is achieved by the use of an extractive sample conditioning system to remove the water component.

NOTE If an in situ analyzer is allowed, a satisfactory determination of the stack gas water content must be attained for dry basis correlation, typically by grab sample and lab analysis during stack testing. The majority of NOx analyzers used in flue gas analysis are based upon chemiluminescence, UV, or infrared technology.

7.3.6.8 Opacity

Opacity analyzers monitor the amount of visible emissions, smoke or opacity created during the combustion process. Opacity monitors or continuous opacity monitoring systems (COMS) are used most often to comply with EPA requirements. Opacity monitors used for compliance opacity monitoring must meet *CFR* 40, Annex B to Part 60, Performance Specification 1. Compliance opacity systems are designed to match the photopic response of the human eye; and the opacity monitor readings are corrected for stack exit opacity, so the opacity that the instrument measures, will match the opacity reading of the visual observer.

Opacity monitors that are for non-compliant opacity measurements are not required to meet the EPA design criteria for continuous opacity monitors.

Both light absorption and light modulation opacity technology are available with light absorption being less accurate at low particulate levels. Light modulation or scatter measure the signal variations arising from the momentary blockage of light as a particle crosses the beam. They are therefore less affected by fouling and misalignment, but are vulnerable to uneven particle distribution, turbulence, and also measure humidity as particulates.

Light absorption opacity monitors that use LED technology are more popular since they eliminate the problems associated with an incandescent light source. They consist of two components, a light source and detector, mounted on a flue gas duct or stack opposite each other. The measurement is indicated in percent attenuation or by a weight per volume particle density.

Where the boiler fuel creates particulate emissions that must be kept below a certain limit, the opacity analyzer output may be used as an air/fuel control constraint to maintain adequate excess air to keep particulates below the limit.

7.3.7 Flame Safeguard Instrumentation

7.3.7.1 General

Flame safeguard instrumentation consists of a flame detector that senses the flame, an amplifier that receives the detector’s output signal, and a relay for signal transmission. This instrumentation may be composed of separate components or integrated into the flame scanner housing.

There are mainly four different methods used to monitor flames. These are optical flame scanners, ionization detectors, temperature sensors, and sound detectors. This section primarily focuses on optical flame scanners that are commonly used for monitoring flames of boiler burners. A secondary discussion about ionization detectors using flame rods is also included.

Selecting the optimum flame sensor must be based on a multitude of factors including the fuel being fired, single or multiple burners, changes in fuels fired during operation, radiation intensities, and changes in combustion rate.

A properly designed and installed video camera may be used to provide supplementary indication of flame and other conditions inside the furnace, but is not intended to replace the flame detector or considered a substitute for direct visual inspection by operators.

7.3.7.2 Recommendations for Flame Safeguard Instrumentation

7.3.7.2.1 General

All flame safeguard instrumentation should:

a) continuously monitor the flame and send a proof-of-flame signal to the BMS;

b) remove the proof-of-flame signal to the BMS upon loss of flame;

c) avoid nuisance shutdowns due to ambient light influences and other external energy sources such as gamma radiation, X-ray radiation, electromagnetic interference (EMI), radio frequency interference (RFI), etc.;

d) provide sufficient sensitivity;

e) operate in a “fail-safe” mode;

f) provide redundancy when required for reliability;

g) improve availability with a reliable power source, such as an uninterruptible power supply (UPS).

7.3.7.2.2 Recommendations for Floor and Wall Fired Boilers

All flame safeguard instrumentation in floor and wall fired boilers should differentiate the target flame of a specific burner from other burner flames and other radiation sources in the combustion chamber over the full range of boiler load, fuel mix, and burner load.

A proof-of-flame signal that is specific to each burner is essential for the BMS to properly manage the start-up and shutdown sequencing of individual burners.

7.3.7.2.3 Recommendations for Tangentially Fired Boilers

Tangentially fired boiler BMS logic may vary depending on specific vendor recommendations. Therefore, all flame safeguard instrumentation in tangentially fired boilers should:

a) recognize individual fuel inputs at low unit loads and monitor individual burners for flame safety in the same manner as for front fired boilers;

b) account for individual flame envelopes merging into a fireball with a well-defined envelope at increased firing rates;

c) account for the possibility that when a tangentially fired boiler in “fireball” mode, individual flame detectors may sense flame even when the corresponding burner is not in operation;

d) revert back to individual burner flame detection if the boiler load subsequently drops below the minimum fireball threshold.

7.3.7.2.4 Requirements for Igniter Flame Safeguard Instrumentation

Burners with Class 1 continuous igniters shall have the main burner flame proven either by the flame detector or by the igniter being proven.

Burners with Class 2 intermittent igniters shall have at least two flame detectors. One detector shall be positioned to detect the main burner flame and shall not detect the igniter flame. The second detector shall be positioned to detect the igniter flame during prescribed light-off conditions.

Burners with Class 3 interrupted igniters shall have at least one flame detector. The detector shall be positioned to detect the igniter flame. It also shall detect the main burner flame after the igniter is removed from service at the completion of the main burner TFI. If more than one detector is provided for improved reliability, both detectors may be positioned to detect the igniter flame. Additionally, both detectors shall be aligned to detect the main burner flame after the igniter is removed from service at the completion of the main burner TFI.

7.3.7.3 Optical Flame Scanners

7.3.7.3.1 General

Optical flame scanners convert radiation emitted by the flame into electrical signals utilizing either the release of electrons creating a current in quartz glass vacuum tubes or the fluctuations in the frequency and amplitude of the radiation signal from flames by semiconductor photo elements. Depending on the fuel fired, different optical detectors with different ranges of spectral wavelength sensitivities are used.

7.3.7.3.2 Semiconductor Photo Cell Flame Scanners

Semiconductor photo cell flame scanners operate according to the internal work function of the detecting matter typically consisting of a photoresistor or photodiode. Semiconductor flame scanners are manufactured to detect specific ranges of wavelengths, depending on the type of fuel that is being fired.

This technology recognizes the dynamic behavior of flames (flame flicker) for meeting the requirement of security against extraneous light sources. Adjustable filters of defined cutoff frequencies enable the scanner to recognize a specific flame and differentiate between other adjacent flames and constant radiation sources such as combustion chamber walls and tube bundles.

By selecting semiconductor material in combination with electronic filters, semiconductor photo cell flame scanners may be designed to be unaffected by X-ray or gamma ray wavelengths, thus avoiding the need for bypassing flame scanners during radiography activity.

7.3.7.3.3 UV/IR Flame Scanner

UV/IR flame scanners base the proof-of-flame signal on UV and/or IR signals. The choice of UV, IR, or combination UV/IR flame scanners should be based on the application.

a) Liquid fuel firing may emit both UV and IR signals, depending on the combustion conditions.

    1) Light oil firing produces a UV signal.

    2) Oil droplets present when firing heavy oil (No. 5, No. 6, or Bunker C) have a tendency to absorb and, therefore, block out the UV signal. UV signal strength may be improved by focusing the scanner on a portion of the flame where oil droplets are not likely to be found.

b) Most fuel gas firing emits predominantly UV radiation.

c) Components in orange and smoky ultralow NOx flames have a tendency to absorb and, therefore, block out the UV signal.

UV flame scanners may be based on either solid state or vacuum tube technology. Both types satisfy the flame monitoring system requirements.

Vacuum tube flame detectors operate by energizing electrons within the vacuum tube when UV is present, thus resulting in an electrical signal. Nuisance trips caused by radiography are a shortcoming of this technology since X-ray and gamma ray wavelengths from radiography may energize the vacuum tube. When the scanner is in the self-test mode with the mechanical shutter closed, it is programmed to fail-safe if the vacuum tube continues to be energized. This may result in a burner trip or a boiler MFT.

7.3.7.3.4 Recommendations for Optical Flame Scanners

All optical flame scanners should have the following.

a) Line-of-sight needs to be considered during the original design. Scaled drawings indicating the flame scanner field of view relative to the burner components and flame envelope make this possible.

b) Indication of the optical flame scanner signal strength available on the burner deck, within view of the corresponding scanner. This monitor provides a means for the operator to observe the output signal strength during scanner adjustments.

c) An adjustable swivel mount for the scanner sighting tube should be provided to facilitate sighting adjustment. During initial burner commissioning, field tests are used to confirm flame scanner settings along with sighting angles.

d) Air purged sighting tube to keep the detector clean, the detector temperature within safe limits, and the sight path free of dirt. The detector should be located to minimize dirt or moisture on the sensor lens or sight glass.

e) A self-check feature during normal operation that removes the proof of flame signal to the BMS if a malfunction is detected.

f) Defined self-check timer interval, fault output timer, and FFRTs that meet system requirements by boiler user and supplier. Some U.S. organizations suggest using 4 s as the time a scanner should indicate flame off to represent that the burner has totally lost its flame. In Europe, intervals discussed are 1 s for gas firing and 3 s for oil firing. However, shorter timing may produce more nuisance shutdowns.

g) Care taken to follow the manufacturer's recommendation for cable type and distance requirements. Cable should not be routed with any high voltage wiring used for igniters. As a general rule, power cabling and signal cabling are separated to mitigate nuisance trips.

An optical flame scanner's discrete (on/off) signal is used for trip functions. However, flame signal strength (e.g. analog) may be utilized for monitoring by the BPCS and for alarm functions.

7.3.7.4 Flame Rods

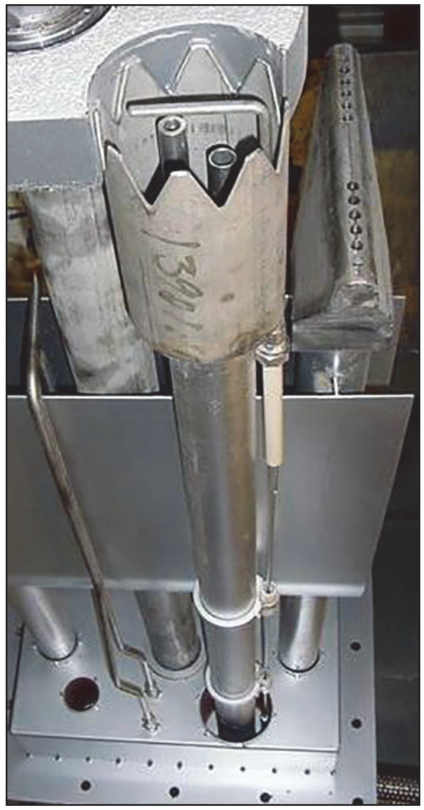
A flame detection system using a flame rod should be capable of verifying the presence of the igniter flame over the full range of test conditions applied to the igniter itself. The flame ionization rod is a consumable requiring periodic replacement. It is generally used only to detect the igniter flame. Even the highest quality flame rod may not last long if used in the main flame.

Flame rods are available in several design configurations, as follows.

a) External electrode extended above and angled over the igniter. In many cases the electrodes are supported from the mixture tube using brackets incorporating ceramic. Particular attention should be paid to avoid fouling and damage to the electrodes that may cause loss of signal. Attention should be given to sealing the electrical termination at the bottom plate. The flame rod is located within the igniter shroud and will only detect flame stabilizing within the tip. Figure 16 shows an igniter for a tangentially fired boiler burner. Section 6.6.4 describes tangentially fired boilers.

b) External straight electrode alongside the igniter. This design relies on flame exiting ports in the igniter shroud and contacting the electrode contained within a cylindrical sleeve. The igniter flame needs to be stabilizing correctly within the shroud for this to function. The electrode is generally fully contained within a protective tube.

c) Internal electrode. The electrode is located within the mixture tube, which provides some protection.



NOTE Image rotated 90° for clarity.

Figure 16—Burner Igniter with Flame Rod

Flame ionization rod installation should consider metallurgy, ease of removal (online or not), potential for electrical shorting, maximum operating temperature, and the recommendations of the igniter burner and flame rod manufacturers.

7.4 Control Systems

7.4.1 General

Boiler control systems regulate the boiler process, including the CCS. These systems are separate from the BMS. These control systems respond to input signals from the equipment under control and/or from an operator and generate output signals, causing the equipment under control to operate in the desired manner.

These control system functions provide a means of optimizing the production of steam safely at the desired pressure, temperature, and purity.

The control system should be adequate to cover all boiler operating conditions of the boiler during start-up, normal operation, transitory and upset conditions, and shutdown. It should be capable of maintaining the required preset header pressure, drum level, and fuel-to-air ratio for safe and efficient firing, as well as allow for preferential firing, when specified.

Provision should be included for indication and adjustment of all necessary set points at the main control location.

• The owner shall determine which final control devices require the ability for direct manual control.

7.4.2 Band of Control

7.4.2.1 General

The band of control for a controlled variable is the set of acceptable values for that variable at a given firing rate. The controlled variables for a boiler include steam drum pressure, steam drum water level, superheated steam temperature, combustion air flow, fuel flow(s), FGR flow (if applicable), and blowdown flows. The upper and lower bound on the set of acceptable values for each variable is determined by such factors as:

a) maintaining flow through the steam generation tubes,

b) adhering to NOx and CO emission limitations,

c) maintaining flame stability,

d) avoiding flame impingement,

e) maintaining boiler mechanical components within mechanical ASME *Code* limits,

f) the difference between actual and indicated flows due to differences between actual and design conditions.

The boiler, burner(s), instrumentation, final control elements, and control scheme should be designed to ensure the controlled variables are maintained within each variable's band of control across the boiler's whole operating range-from low firing to high firing, including steady state load demand, load changes, and upsets. In general, narrow bands of control require slow boiler ramp rates, tight final control elements (accurate positioning, little dead band, etc.), and finely tuned control loops.

- Prior to boiler design, the band of control for each controlled variable should be defined for steady state load demand, load changes, and excursions. Otherwise, the desired set point at certain operating conditions may not be achievable due to design limitations. See Table 13 for the suggested bands of control.

Table 13—Bands of Control

	Steady State	Load Change	Upsets
Steam drum pressure [a]	±1 %		
Steam drum water level [a]	±25 mm (1 in.)		
Superheated steam temperature (when controlled) [a]	±5 °C (10 °F)		
Air/fuel ratio [b] (expressed in terms of deviation from target O_2 in flue gas)	$\pm ^1/_2$ %O_2	±1 %O_2	$\pm 1^1/_2$ %O_2
Flue gas recirculation rate [b] (see Note)	±5 %	$\pm 7^1/_2$ %	±10 %

NOTE ±5 % band of control may be required for ultralow NOx burners.

[a] B. Liptak, *Instrument Engineers' Handbook*, 4th Ed., *Process Controls and Optimization*, Vol. 2, ISA, p. 1574.

[b] ABMA 307, *Combustion Control Guidelines for Single Burner Firetube and Watertube Industrial/Commercial/Institutional Boilers*, 1999, p. 44.

7.4.2.2 Turndown

There are several components to a boiler that may have their own specific turndown condition, but the criterion of boiler turndown is usually defined as the lowest steam production (at design pressure) that the boiler can achieve and still maintain the required (specified) steam temperature. Sometimes, the purchaser may intend that the turndown requirement is for the minimum stable steam production (or boiler operation) at design pressure with reduced outlet steam temperature. It is important that the specific turndown requirement be established during design.

- The owner/operator should specify the turndown required. Choices include:

  a) hot standby,

  b) specified percent of MCR firing rate.

Modifications to procedures, final control elements, control loops, and hardware may be required if narrow bands of control are to be maintained at turndown conditions. Dynamic modeling and/or air flow modeling may be helpful during the boiler design stage to evaluate the impact of such changes.

In Chapter 5 of *Low Load/Low Air Flow Optimum Control Applications* [7], several recommendations are provided for enhancing operation at turndown conditions. Key recommendations include the following.

a) It is recommended that all control valves be checked for correct operation. Solutions may include modifying the controller settings, linearizing the valve response or installation of a new valve with a more suitable characteristic. Under certain circumstances, it may be more worthwhile to install a bypass valve for low load control. Again, the use of modeling and simulation together with plant testing may assist in identifying the problem valves.

b) At low loads it is very important to provide accurate control of both the air and fuel flow. The main factor that affects this is the accurate measurement of the combustion air and fuel flow.

c) In order to accurately control the combustion air, it is useful to have individual accurate and repeatable actuating mechanisms with position feedback on each burner.

d) It is important to evaluate the design of the existing burners and make sure that they are suitable for extended low load operation.

e) Three-element feedwater control may not be possible at low load. This is due to the inaccuracy of the feedwater flow measurement at low loads.

7.4.2.3 Rate of Load Change

When boilers are used in a centralized facility to supply steam to the general plant, they are often required to be able to accommodate the varying load conditions in the plant. This often requires these utility boilers to be able to operate with rapid load changes. They shall increase their loads when a process steam producer stops making steam or when a heavy steam user comes online. Although usually less of a problem, these boilers shall also be able to handle rapid load variations when a steam using process drops off or when an auxiliary steam producer comes online.

- The owner/operator should specify the required rate of load change.

A common rate of change is 10 % MCR per minute. Faster rates of change are possible, but may affect mechanical and process design considerations. In general, the selected ramp rate should consider width of bands of control, %MCR at turndown, final control elements (accurate positioning control tolerances, little dead band, etc.), feedforward control logic, control loop tuning, effect on design of steam drum size, possible change of downcomer sizing, mechanical changes to tube penetration design features, and whether some carryover of solids into the superheater coils can be tolerated.

7.4.3 Control Mode

7.4.3.1 Automatic Control

Automatic control is the recommended mode of operation of all new and existing oil and gas fired boilers. With all control loops in automatic, safe and efficient operation is facilitated by keeping all boiler operating parameters at their set points and within design operating limits.

For units that operate over a load range (as opposed to on/off operation), automatic control loops should include as a minimum: drum level/feedwater flow control, steam temperature control (when steam is superheated and or reheated), combustion air flow control, fuel flow control, and furnace draft control (when balanced draft). Additionally, for larger boilers or steam systems with multiple boilers operating at pressures in excess of 400 psi, automatic control of feedwater, condensate return, makeup water, and boiler (drum) water quality will aid in maintaining optimum water and steam quality conditions.

7.4.3.2 Manual Control

With the availability of automatic controls and their proven reliability, no oil or gas fired boiler should have only manual operation. Manual control of oil or gas fired boilers should only be done on a temporary basis when automatic control loops are out of service. Constant operator attendance is required and only those control loops that are unable to operate in the automatic mode should be controlled manually.

Initial and refresher training for operators, as well as documented and readily accessible operating procedures are important in providing operators with the skills necessary to assume manual control of one or more boiler control loops.

Manual operation increases the likelihood that a boiler operating parameter will exceed its safe operating limit. It is, therefore, very important that safety interlocks are not bypassed while one or more control loops are in manual.

7.4.4 Master Pressure Control

Header pressure is the key variable for steam generator control. The master pressure controller (also referred to as the master load controller) compares the pressure in the main steam header with its set point pressure and automatically adjusts its output to one or more boilers' combustion controls to request more or less steam. If the steam demand is subject to significant fluctuation, consideration should be given to feedforward action on the master pressure controller output.

Typically, in a multi-boiler plant only one boiler modulates and responds to plant demand swings. There are scenarios where multiple boilers need to modulate and respond to plant demand swings to account for large load swings. When two or more units are operated in parallel, they shall share the total load in varying proportions. In order to divide the total load, the output signal of the master pressure controllers (firing plant rate) is fed into a loading station (boiler master) provided for each steam generator. This instrument allows the operator to bias the master pressure controller output signal and thus allocate the desired portion of the total load to each unit. It also permits base loading each boiler with the master pressure controller in manual mode.

Where plant operating practices permit, economical operation is often obtained when the most efficient unit is operated at a substantial, but steady, base load, while one or more units operate to automatically handle swing loads.

The steam generating rate on the base-loaded unit may be manually adjusted as necessary so that the unit(s) on automatic control remains within satisfactory steaming range. In some instances it may be desirable to operate a steam-generating unit base-loaded on flow control, as illustrated in Figure 17. Under this method of operation the steam flow transmitter output (corrected for static pressure where used) is fed to a flow controller that is manually switched into service when base-load operation is required.

Pressure compensation of a volumetric steam flow measurement is recommended to reduce the likelihood of the flow controller being momentarily upset by load changes large enough to cause significant pressure changes in the main steam header. For example, an increase in load will cause header pressure to drop. This results in a transient increase in steam flow from the steam generator to the header, so the initial response of the flow controller will be to reduce firing at a time when the steam generators that maintain header pressure are increasing the firing rate.

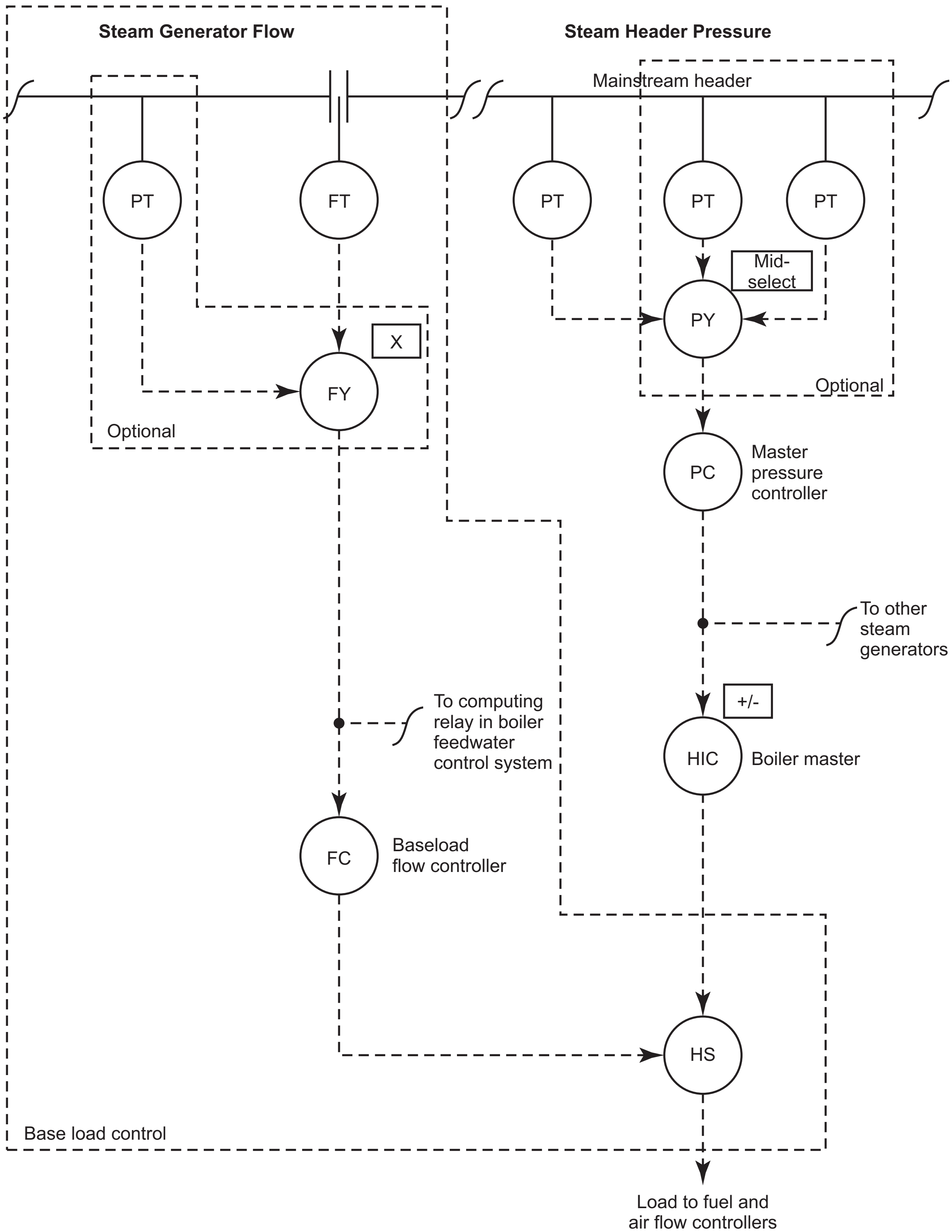


Figure 17—Typical Steam Generator Load Controls

7.4.5 Water Side and Steam Side Controls

7.4.5.1 General

Boiler controls are used to supply sufficient water while maintaining an optimum water-steam interface in the drum. The drum level controls are designed to provide a continuous mass-heat balance by replacing the mass of steam leaving the boiler by an equivalent mass of feedwater. The water level is constantly monitored to avoid high water carryover or low water trips.

7.4.5.2 Types of Control Strategies

7.4.5.2.1 General

The commonly used modulation control types are single-element, two-element, and three-element controls. The selection on any one of the three strategies depends on size of the boiler and load variations.

7.4.5.2.2 Single-element System

In a single-element strategy, the drum level is controlled using only level measurement. The level device measures the instantaneous water level and provides a control signal that operates the feedwater valve in order to maintain desired water level in the drum (Figure 18).

This is the simplest water level control strategy and is used on boilers with steady demand load changes where the supplied feedwater pressure is constant. For boilers that require more than single-element control, single-element strategy is recommended only during start-up until sufficient load has been established to reach control ranges for three-element feedwater control system. The operating pressure of the steam drum may be measured for each steam generator. This pressure will normally be indicated on the boiler's local control panel, but may also be input to the BPCS. In addition, the boiler drum shall be fitted with a local pressure gauge.

For the single-element system, the shrink and swell effect of steam bubbles in the drum causes an erroneous initial control reaction, which can lead to over or under filling of water. As steam load increases, there is an initial decrease in drum pressure resulting in an artificial rise in drum level as the steam bubbles expand and swell the drum water level. The level transmitter sends a signal to reduce feedwater flow, when in fact the feedwater flow should be increased to maintain the load increase. On the other hand, a decrease of steam load increases drum pressure resulting in the shrinking of steam bubbles in water. The shrinking in turn causes an initial fall in drum level consequently resulting in an increase of feedwater flow when in fact it should be decreasing to maintain mass balance. In these cases, two- or three-element feedwater control shall be provided.

Shrink and swell effect caused by moderate load swings can result in:

a) nuisance alarms or trips,

b) saw tooth type flow rates,

c) excessive fuel and maintenance costs.

The level signal may be pressure compensated if the drum level measurement is sensitive to density variations.

7.4.5.2.3 Two-element System

A two-element system uses two process variables, drum level and steam flow, to regulate the feedwater demand. The drum level difference between the desired set point and the instantaneous measurement is summed up with the steam flow process variable to position the feedwater control valve. Since steam flow is very dynamic, this feedforward signal establishes the initial feedwater flow control valve position. Feedback drum level control trims the initial position to bring the process back to the set point. This ensures the initial response of the drum level control is in the correct direction to minimize the deviation from set point, even during moderate load changes (Figure 19).

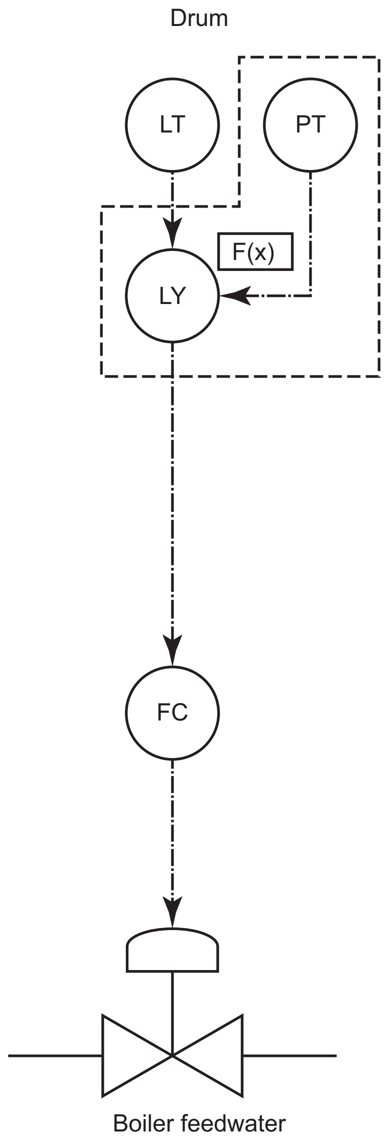


Figure 18—Single-element Feedwater Control System

The drawback with this system is that it does not regulate for pressure or load disturbances in the feedwater supply since this is not a measured variable. Also, two-element control cannot cope with phasing interaction between feedwater flow and drum level because of the combination of fast steam flow response and the relatively slow process of the drum level is controlled. This may lead to sub-cooled drum water on a large increase in demand by allowing excessive feedwater to enter the drum without consideration to the boilers thermal dynamic capabilities. Therefore, control improvement considerations for existing applications include adding a pressure transmitter and/or PRV/PCV/VFD on the feedwater side to regulate header pressure disturbances, and a temperature compensated signal from the steam flow transmitter.

7.4.5.2.4 Three-element System

The three-element system maintains water input using three variables: drum level, steam flow, and feedwater flow (Figure 20). The feedwater flow is added to the two-element system to handle interaction between feedwater flow and drum level. The feedwater flow controller compares the process variable signal of feedwater flow with the feedwater demand signal and provides a corrective action to position the feedwater control valve. Therefore, every pound of

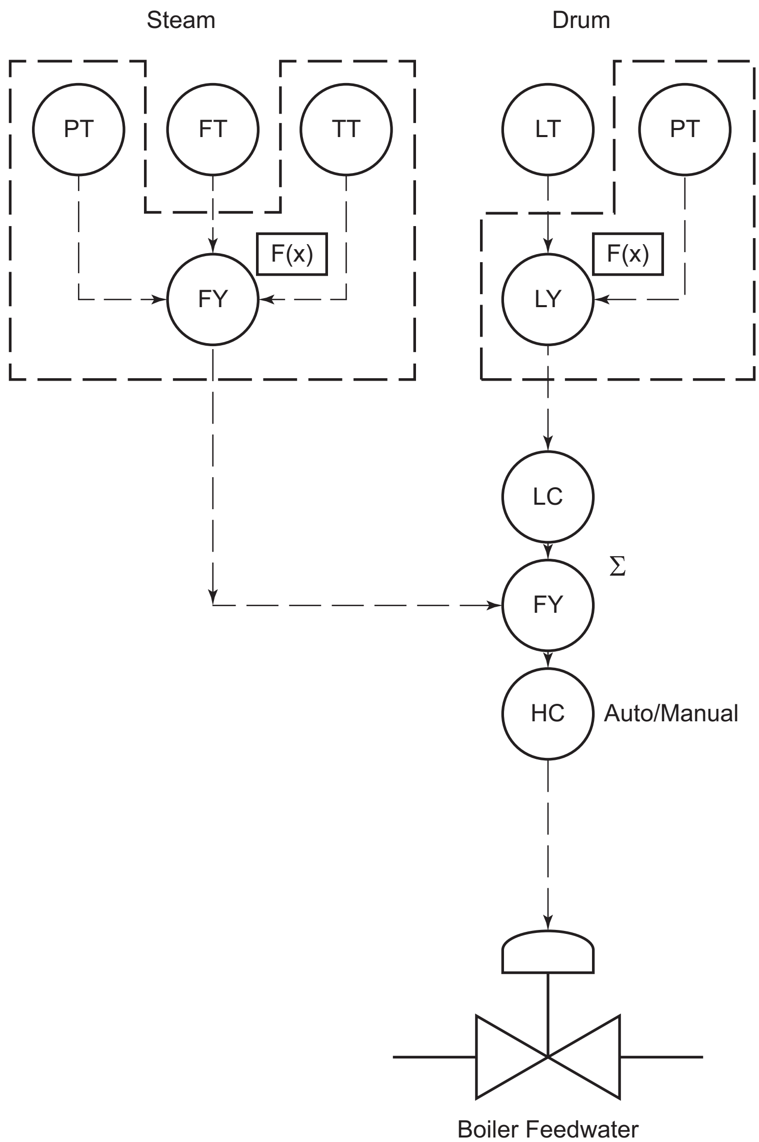


Figure 19—Two-element Feedwater Control System

steam flow leaving the boiler is replaced by a pound of feedwater. This loop has final control on the feedwater valve. As the remote set point from the two-element level control changes with steam flow and drum level variations due to blowdown or other minor losses, the feedwater controller modulates its output to regulate the necessary feedwater flow to keep the drum level in a mass/heat balanced and level state. It is possible for that the feedwater flow signal to be temperature compensated to regulate for temperature effects on water density. On multiple steam generator installations with common feedwater piping systems, feedwater header pressure is sometimes regulated at some fixed value above the highest drum pressure. Feedwater temperature may be measured using a resistance temperature device or a thermocouple. This temperature is normally input to the BPCS. Low feedwater temperature should be alarmed as an indication of abnormal deaerator operation.

The three-element system is recommended for any size boiler that is subject to very wide and rapid load changes and for multiple boilers sharing the same feedwater header and supply system.

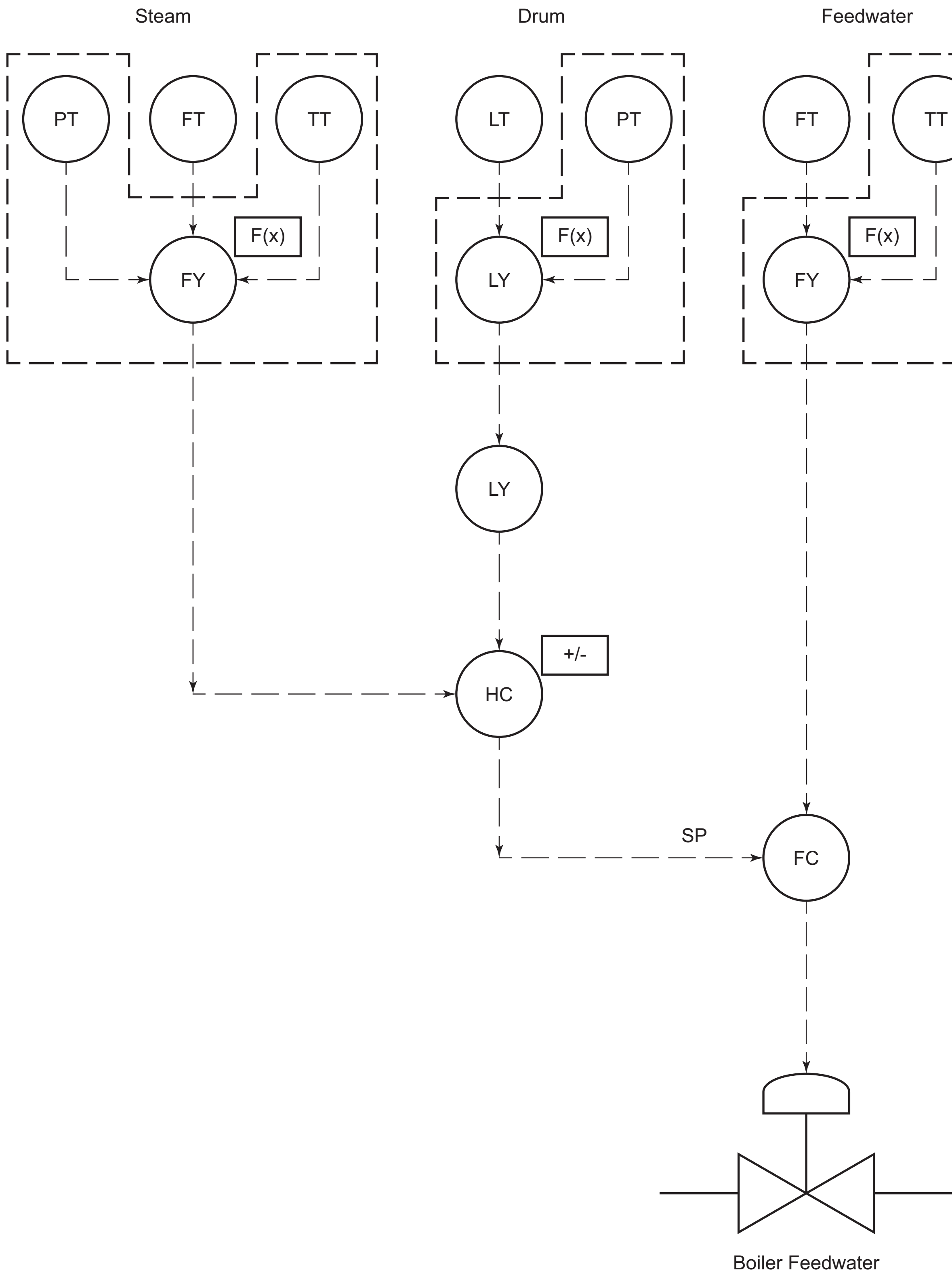


Figure 20—Three-element Feedwater Control System

7.4.6 Combustion Control

7.4.6.1 General

Steam demand and supply in refineries and petrochemical facilities can change suddenly, depending upon operating conditions and upsets anywhere in the steam system. Therefore, the boiler should have effective process controls that set fuel firing to match the changing demand for steam. In addition, the firing should be controlled to provide efficient combustion.

Combustion is controlled by adjusting the fuel flow and combustion air flow to meet demand for steam while maintaining the proper air-fuel ratio. There are three basic classifications of CCSs, namely: single point positioning, parallel positioning, and metering control systems.

In general, for smaller boilers [10,000 kg/h (22,000 lb/h) and under] with a single burner firing a non-varying fuel (i.e. a constant HHV) at a nearly constant load, with a minimum ambient temperature swing or an indoor installation, a single point positioning system may be considered.

For boilers in the approximate range of 15,000 kg/h (33,000 lb/h) to 40,000 kg/h (88,000 lb/h), firing a single fuel using a single burner with a fairly constant load, but varying HHV of the fuel or located outside with a large swing in temperatures, an oxygen trim system would be desirable. A parallel control system would provide an opportunity to install an oxygen analyzer and incorporate O_2 trim to compensate for HHV changes or air temperature variations in such systems.

For large boilers [over 40,000 kg/h (88,000 lb/h)] firing a fuel with a varying HHV or firing multiple fuels in either a single or multiple burners, and with large temperature swings and/or required to quickly swing steam loads, a full metering system with lead/lag and oxygen trim is recommended. This is the preferred control system since refineries and petrochemical facilities typically fall under these criteria. If multiple fuels are fired simultaneously, then each fuel should be measured and a firing rate totalizer should be incorporated in the combustion controls to ensure the boiler or burner is not overfired.

7.4.6.2 Single Point Positioning Control

7.4.6.2.1 Overview

Single point positioning control is commonly referred to as a jackshaft system. Neither fuel flow nor air flow is measured (open loop control) and their relationship is maintained by mechanically linking with a jackshaft. The theory behind the jackshaft system assumes that every position of the fuel valve represents a repeatable value of fuel flow and corresponding matching position of the air control element represents a repeatable air flow.

In practice, single point positioning systems have a limited number of final control elements. Typically, one combustion air damper and one or two fuel flow control valves are linked to the jackshaft.

Automatic air/fuel ratio trim control and/or FGR control may be incorporated into a single point positioning control system. Example functional drawings for single point positioning control are shown in Figure H.1.

7.4.6.2.2 Measurements Required

Single point positioning control requires the measurement of steam header pressure as an input to the control scheme.

7.4.6.2.3 Control Scheme

Single point positioning control consists of a steam pressure master controller, a characterization function, and a single actuator to position the common jackshaft, which, in turn, directly positions both the fuel valve and air control linkage. See Figure 21 showing single point positioning control.

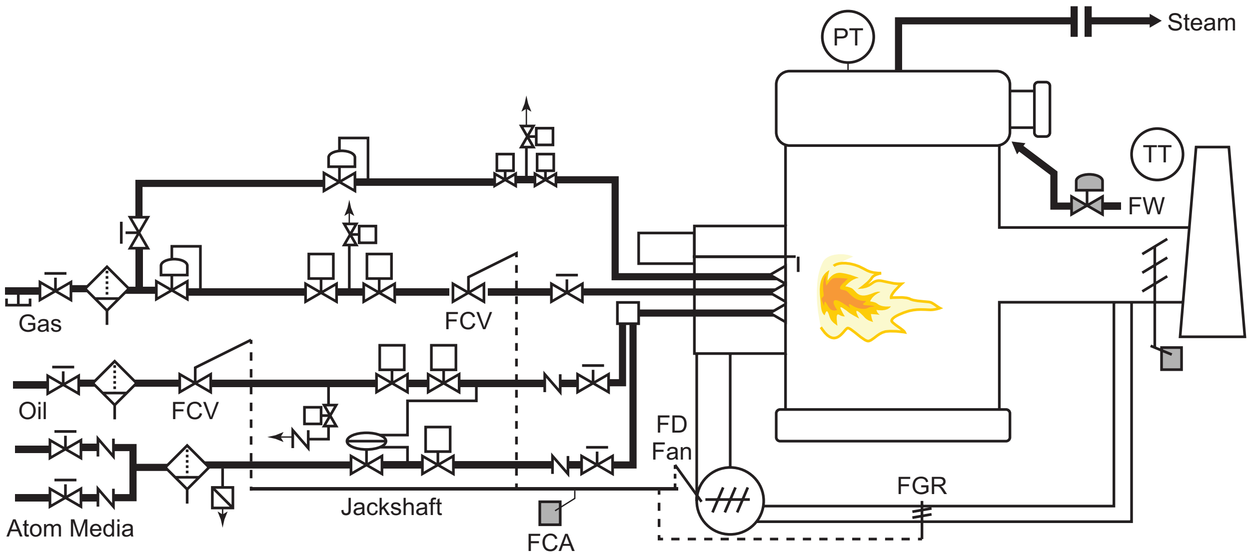


Figure 21—Single Point Positioning Control

7.4.6.2.4 Characterization Function

Characterization of the fuels and air flow is through manipulation of cams and linkage angularity adjustments. Because fuel valves and air dampers have different flow characteristics, it is necessary to linearize these flow characteristics. Typically, the air flow characteristic is linearized first, and then the fuel flow characteristic is linearized to match the air flow. When properly aligned, the percentage of fuel and air flow will match the percentage demanded by the single control output.

7.4.6.2.5 Recommended Use

Single point positioning control is best suited for boilers of the following characteristics.

a) Single burner configuration with an MCR not exceeding 10,000 kg/h (22,000 lb/h).

b) Steady and reliable supply side fluid properties, including consistent boiler outlet conditions.

c) Single fuel (with a constant heating value) firing. Firing of two fuels is possible although the fuels cannot be fired simultaneously, and generally this system will fire one of the fuels with significantly higher excess air since only one air flow control element is provided for both fuels.

d) Indoor installation or outdoor installation with minimal ambient temperature swing.

The inherent safety and simplicity of the single point positioning system have been its hallmark for many years and it is still widely used on boiler packages with the abovementioned characteristics. The biggest disadvantages of this type of mechanically matched systems are the limited flexibility to match the fuel and air over the entire load range, which normally requires difficult characterization to be performed on both the fuel valve cam and air flow control linkage in the field during initial start-up. In addition, this system cannot compensate for wear of the mechanical parts or changes in the heating value of the fuel fired. Over time this would significantly decrease the boiler's overall efficiency. To allow for short comings, this type of control system normally is designed to operate with a higher percent of excess air for the worst case to avoid dangerous fuel-rich situations.

7.4.6.3 Parallel Positioning Control

7.4.6.3.1 Overview

A parallel positioning CCS provides for simultaneous operation of the air flow control element and fuel flow control valve via separate actuators according to the firing rate demand signal developed by the master steam pressure controller. This system is the first level of improvement to the previously discussed jackshaft system. Neither fuel flow nor air flow is measured (open loop control), rather both are inferred by the position of the final control elements.

The number of final control elements should practically be limited to prevent the additive system error introduced through the deviation of each element to result in an excursion beyond the band of control while all of the final control elements are still within their allowable deviation range. Automatic air/fuel ratio trim control and/or FGR control may be incorporated into a parallel positioning control system.

Example functional drawings for parallel positioning control are shown in Figure H.2.

7.4.6.3.2 Measurements Required

Parallel positioning control requires the measurement of steam header pressure as an input to the control scheme.

7.4.6.3.3 Control Scheme

Parallel positioning control includes a master steam pressure controller, either a manual air/fuel ratio bias adjustment or a load to combustion air flow characterizer, two linear characterization functions, a fuel flow control actuator, and an air flow control actuator. The master steam pressure controller maintains the steam header pressure at set point by manipulating the firing rate demand.

A simplified control diagram is shown in Figure 22. See Annex H for more in-depth control diagrams.

7.4.6.3.4 Characterization Functions

The fuel valve characterization function creates a linear relationship between the fuel demand and the typically non-linear valve characteristic. The FD fan damper (or variable speed drive) characterization function does the same for combustion air demand. When utilized, the load to combustion air flow characterizer changes the combustion air flow set point based on fuel demand.

- When utilized, the owner/operator should specify the load to combustion air flow characterizer’s output values at approximately 10 equally spaced operating points across the entire firing range of the boiler.

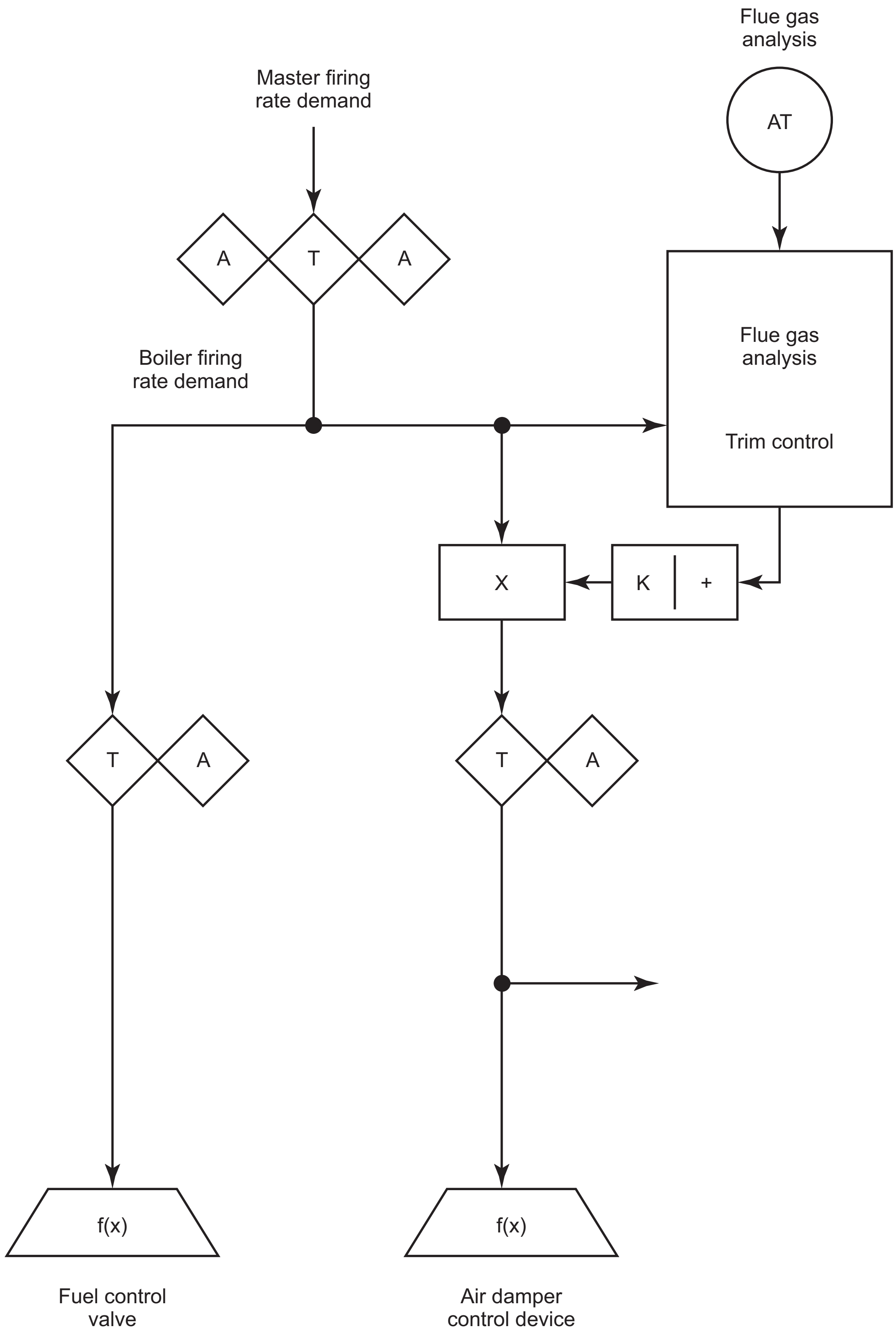
The potential always exists in parallel positioning applications for one of the final driven units to fail, or lose calibration. In this scenario, the fuel/air ratio will no longer track per original set-up, and the system may not perform safely or efficiently within the band of control. To minimize this potential, parallel positioning control applications require a position feedback signal from each of the driven control elements to monitor the deviation between the actual position of each driven control element and the position called for by the controller over the load range. Should any given position deviation exceed the predetermined limit for safe and reliable operation, a MFT is to be immediately sent to the flame safeguard.

7.4.6.3.5 Recommended Use

Parallel positioning systems are best suited for boilers of the following characteristics.

a) Single burner configuration with an MCR in the range 30,000 to 80,000 PPH.

b) Steady and reliable supply side fluid properties, including consistent boiler outlet conditions.



Source: S. Dukelow, *The Control of Boilers*, Second Edition, ISA, Research Triangle Park, North Carolina, 1991, p. 317.

Figure 22—Parallel Positioning Control

c) Single fuel (with a constant heating value) firing. Firing of two fuels is possible although the fuels cannot be fired simultaneously and generally this system will fire one of the fuels with significantly higher excess air since only one air flow control element is provided for both fuels.

d) Indoor installation or outdoor installation with minimal ambient temperature swing.

7.4.6.4 Metering Control Systems

7.4.6.4.1 Overview

The full metering cross-limiting (or lead-lag) CCS optimizes combustion efficiency throughout the load range of the boiler with air flow leading fuel flow during load increases and lagging the fuel flow during load decreases. Both fuel and air flows are measured (and not inferred as in the two previous systems) and the actual flow rates are used as feedback signals for closed loop control and are compared against the demand established by the boiler master steam pressure controller.

The most significant improvements of this system compared to the two systems discussed earlier are:

a) steam pressure controlled to tighter tolerances,

b) quicker responsiveness to load swings,

c) quicker return to normal after load change,

d) improved excess air flow control,

e) air-rich combustion mixtures maintained during load changes,

f) improve overall boiler efficiency,

g) multiple fuels fired simultaneously based on total summed Btu input.

Automatic air/fuel ratio trim control and/or FGR control may be incorporated into a metering control system.

Example functional drawings for full metering cross-limiting (or lead-lag) combustion control are shown in H.3 (Coen Company, Inc., San Mateo, California 94404).

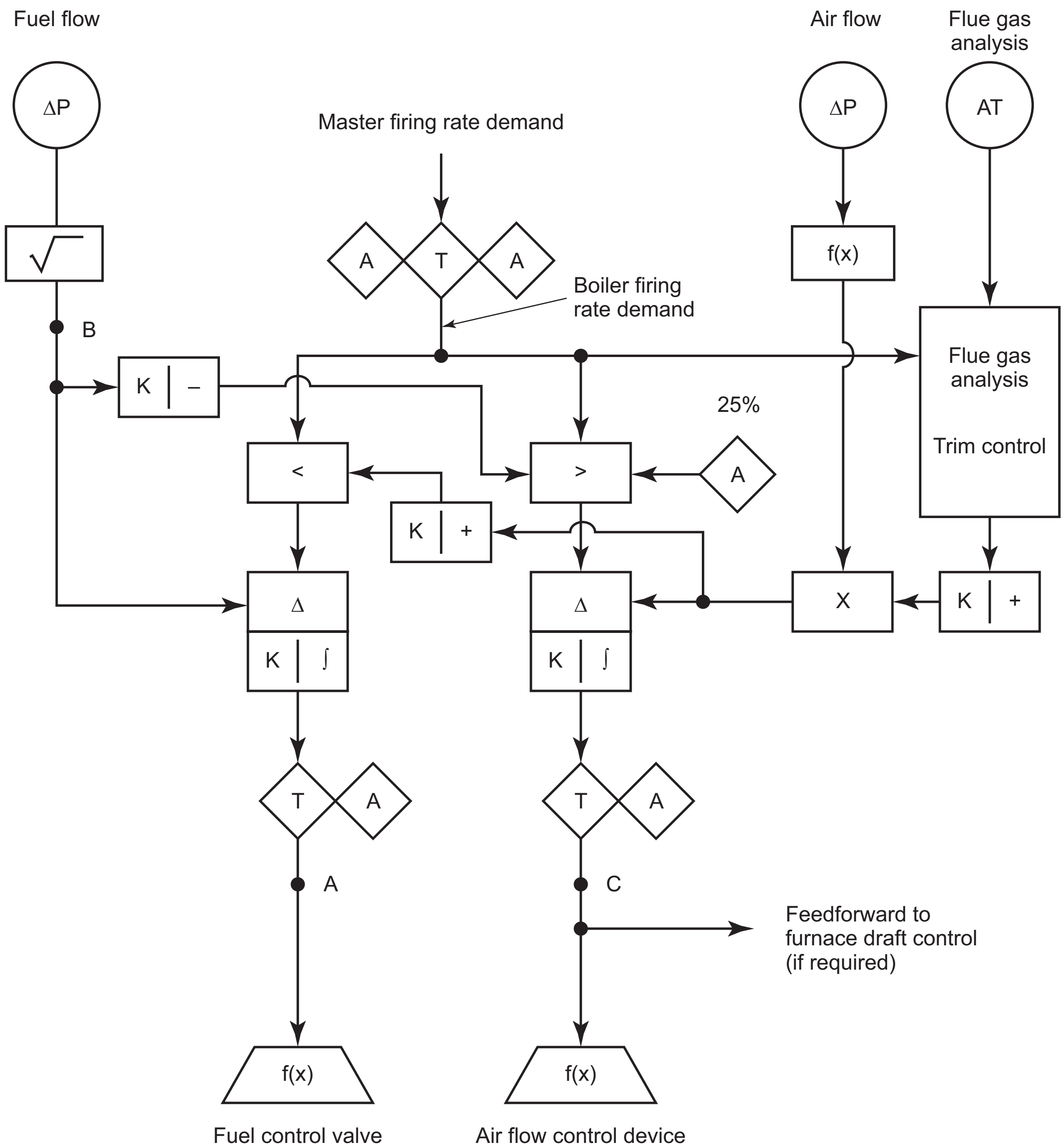
7.4.6.4.2 Measurements Required

Metering control is a cascade control strategy that requires three process variable measurements. The measured variable for the primary loop is steam header pressure. There are two secondary loops, with fuel flow and combustion airflow being the secondary loop measured variables.

7.4.6.4.3 Control Scheme

Metering control systems consists of a master steam pressure controller, a combustion air flow controller, a fuel flow controller, an air flow measuring element, and a fuel flow measuring element. The master steam pressure controller maintains the steam header pressure at set point by manipulating the firing rate demand. A simplified control diagram is shown in Figure 23. See Annex H for more in depth control diagrams.

The metering control system without lead/lag provides stable, accurate control of energy input and fuel/air ratio during steady state operation, but does not guarantee absolute furnace safety during load changes. Therefore, most metering systems today use lead/lag cross-limiting control as an extra measure of furnace safety without sacrificing efficiency.



Source: S. Dukelow, *The Control of Boilers*, Second Edition, ISA, Research Triangle Park, North Carolina, 1991, p. 320.

Figure 23—Metering Control

In lead/lag cross-limited metering control, maximum-and-minimum-signal selectors provide a positive interlock to prevent fuel-rich conditions on a load change. Air always leads fuel on an increase and lags fuel on a demand decrease. However, the safety of a cross-limited system can be jeopardized by a failed air or fuel flow transmitter.

Under steady state conditions, fuel and air flow controllers continuously hold measurement equal to set point. On steam-demand increase, the low-selector module blocks the increase to the fuel controller and makes the controller set point equal to actual air flow. In this way, fuel flow cannot increase until after air flow has increased.

7.4.6.4.4 Characterization Functions

In a metering control system, control loop responsiveness is improved when characterization functions are used to provide a linear flow to position relationship between flow and the controller's position.

The fuel valve characterization function creates a linear relationship between the fuel demand and the typically non-linear valve characteristic. The FD fan damper (or variable speed drive) characterization function does the same for combustion air demand. When utilized, the load to combustion air flow characterizer changes the combustion air flow set point based on fuel demand.

- When utilized, the owner/operator should specify the load to combustion air flow characterizer's output values at approximately 10 equally spaced operating points across the entire firing range of the boiler.

7.4.6.4.5 Recommended Use

Metering control systems are the preferred systems for refineries and petrochemical facilities, as these sites typically require boilers with the following characteristics.

a) Single or multiple burner configurations with an MCR greater than 40,000 kg/h (88,000 lb/h).

b) Varying supply side conditions that exceed the safe limits of oxygen trim compensation.

c) Multiple fuels (with varying heating value) firing simultaneously.

d) Indoor or outdoor installation with large ambient temperature swings.

7.4.6.5 Trim Systems

7.4.6.5.1 %O_2 Trim

The air flow demand is based on the fuel composition and the total fuel flow to the boiler. A %O_2 trim controller is frequently used to correct for uncompensated air flow and to respond to sources of air demand that are not reported to the control system. Examples include:

a) a change in ambient air temperature for uncompensated air flow (see 7.3.4.5),

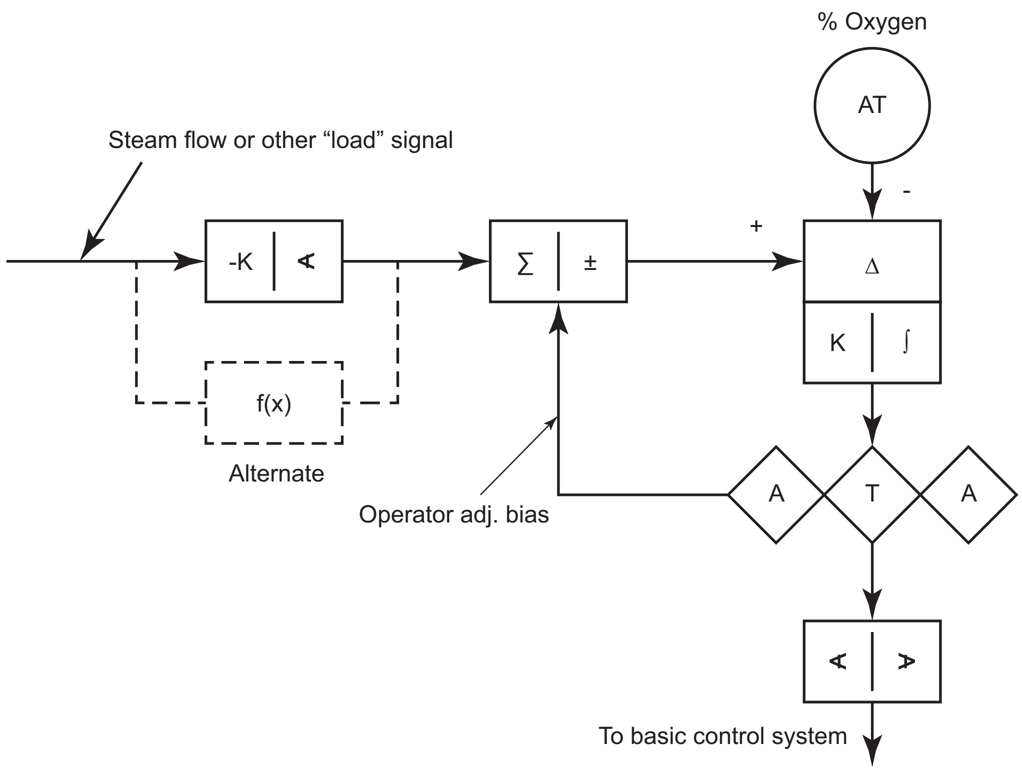
b) a change in fuel gas conditions for uncompensated fuel flow (see 7.3.4.2),

c) an uncompensated change in fuel gas heating value (see 7.3.5).

Depending upon the application, a %O_2 trim controller may adjust either the air flow signal to the combustion air controller (see Figure 23) or the firing rate demand to the combustion air controller (see Figure H.11).

Regardless of the method, trim limits (see Figure 24) should be applied at the output of the trim controller to prevent an oxygen analyzer malfunction from driving the boiler outside of the band of control into an unacceptably high or low oxygen condition. For example, when the band of control at a given firing rate is ±1.5 %O_2 the trim controller should not change the air flow by more than ±7.5 % (i.e. where 1 $\%O_2$ in flue gas is approximately 5 % excess combustion air flow).

A simplified control diagram is shown in Figure 24. See Annex H for more in-depth control diagrams.



Source: S. Dukelow, *The Control of Boilers*, Second Edition, ISA, Research Triangle Park, North Carolina, 1991, p. 267.

Figure 24—Metering Control with O_2 Trim

7.4.6.5.2 Metering Control System with CO Trim

If the boiler includes a laser based flue gas CO analyzer, CO trim may be included in the control scheme. CO trim may supersede the $\%O_2$ trim to the air/fuel ratio controller whenever CO approaches or exceeds the override set point. The CO measurement may also be the primary trim to the air/fuel ratio controller with the oxygen measurement being used as a low override.

As the air/fuel ratio is reduced to generate and maintain a small amount of CO in the flue gas, a point is reached where the CO will increase rapidly. Therefore, for CO trim, an infrared or laser based analyzer technology with a minimum sensor response time of ≤5 s is recommended although ≤1 s is preferred. While CO is detectable with a typical catalytic bead combustibles sensor, it has a response time of 20 s to 25 s to T90 and is not recommended for CO trim. Additionally, a typical catalytic bead sensor has poor low-end sensitivity and is unsuitable for combustion control where operation around 50 ppm CO is required (see 7.3.6.4).

7.4.6.6 Dual/Combination Fuel Firing

A metering control system for a boiler capable of dual fuel firing simultaneously (such as fuel gas and fuel oil) has to account for the total boiler heat input and different air/fuel ratio. Dual firing may include one or more of the following operating modes:

a) one fuel in constant duty with a second fuel automatically following boiler energy demand;

b) both fuels automatically following boiler energy demand.

When firing dual fuels simultaneously, the airflow demand should be characterized based on the ratio of fuels being fired to establish the correct air-fuel ratio. The air-fuel ratio may be adjusted by a $\%O_2$ trim controller. When firing dual fuels simultaneously, the oxygen set point is computed based on the ratio of both fuels.

Caution be should be exercised when simultaneously firing multiple fuels in multiple burner boilers where one fuel is fired in some burners and the second fuel is fired in the other burners. There is a risk of burners for one of the fuels operating fuel rich and the other operating fuel lean even though the overall stoichiometry would appear to be satisfactory.

Waste gas and low-pressure gas firing should be supported by the main fuel oil or gas flame of the burner firing waste gas. The boiler should be operating within its operating envelope whenever waste gas and/or low-pressure gas is introduced.

Waste gas should not be fired, unless the boiler is operating above 25 % MCR.

7.4.6.7 Feedforward-Feedback Control

7.4.6.7.1 General

A feedforward-feedback control system combines control action based on measurements of disturbances to a process with control action based on keeping the output of the process at the desired set point value.

A combined feedforward-feedback control system should retain the superior performance of the first and the insensitivity of the second to uncertainties and inaccuracies. Therefore, any deviations caused by the various weaknesses of the feedforward control will be corrected by the feedback controller. This is possible because a feedback control loop directly monitors the behavior of the controlled process (measures process output) [8]. A simplified control diagram is shown in Figure 25. See Annex H for more in-depth control diagrams.

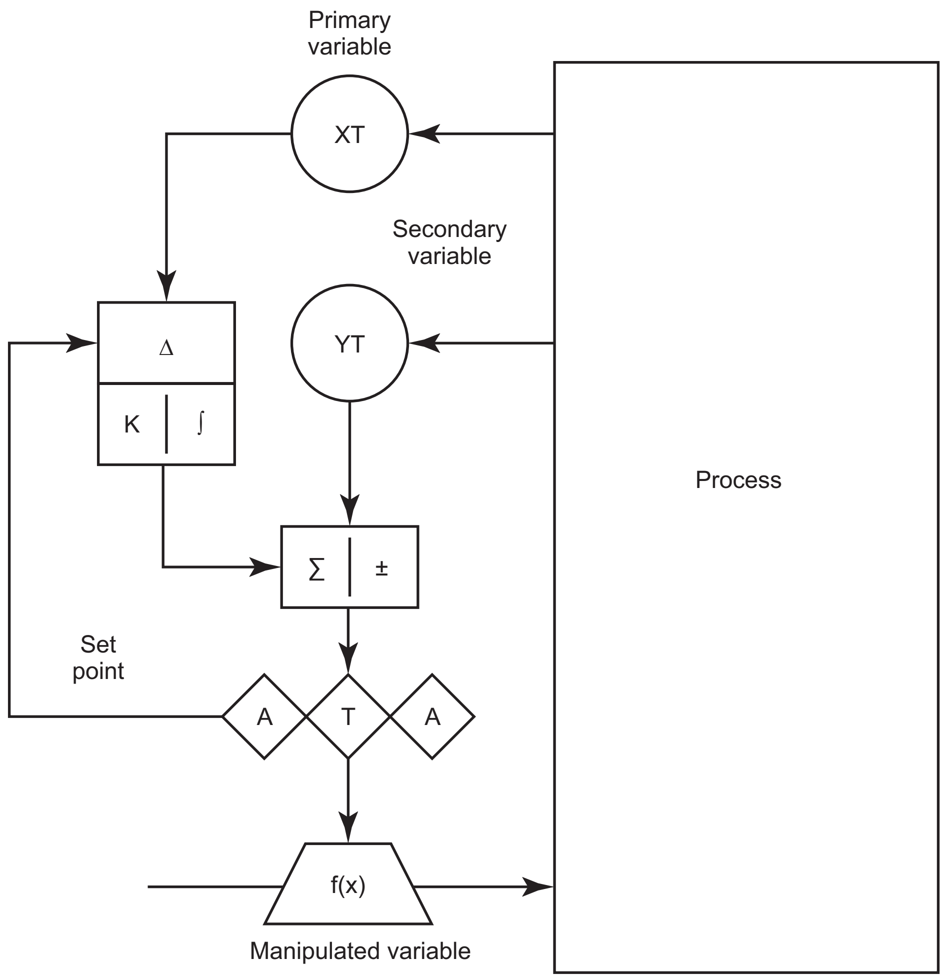
7.4.6.7.2 Btu Feedforward

For applications where significant variations in fuel composition are expected, the control system shall incorporate specific features, other than oxygen trim, to accommodate the variations in the heating value of the fuel.

Fuel gas heating value analysis (see 7.3.5) may be used to compensate the fuel input for heating value excursions. This feature improves plant master response to these excursions and also helps the excess air controls maintain the proper air-to-fuel ratio. In this case, the air-to-fuel ratio is often calculated in terms of SCF air per Btu fuel, rather than SCF air per SCF fuel gas.

7.4.6.7.3 Steam Flow Feedforward

If load changes are rapid, a steam flow feedforward circuit should be applied to an existing header-pressure control scheme to provide swifter corrective action to fuel and air controls during extreme load changes.



(A) Feedforward-plus-Feedback Control

Source: J. Gilman, "Boiler Control Systems Engineering," Presentation given at the Automation Connections ISA Expo, 2005, Slide 12.

Figure 25—Feedforward-Feedback Control System Example

In this two-element steam pressure control arrangement, steam flow provides a feedforward signal that alerts and sets the initial demand for fuel and combustion air. This system improves response of the boiler by anticipating a load change and, therefore, minimizes upsets in the combustion rate and variations in outlet pressure.

7.4.6.8 Draft Control

For balance draft boilers, furnace pressure should be controlled at a stable value. The furnace pressure is usually controlled by adjusting the ID fan damper, ID fan inlet vanes, or ID fan speed. Since furnace pressure is affected by changes in air flow, the combustion air flow demand signal should be used as a feedforward signal to the furnace pressure controller.

7.4.6.9 Flue Gas Recirculation Control

The addition of flue gas to the combustion air reduces thermal NOx generation by decreasing the flame temperature and lowering the local oxygen concentration (see 6.3.7).

The operation of a boiler with external FGR technology is different than once through flue gas operation. The amount of O_2 in the stack and the O_2 concentration in the windbox required for proper combustion vary with the operating load of the boiler, the specific burner, and fuels combusted. As the FGR rate increases as a percent of total combustion air, the specific burner may require control within a more narrow control band to maintain proper combustion.

FGR flow may be induced through the FD fan and mixed with the combustion air, or it may be forced through a dedicated fan. The most widely used approach is induced through the FD fan mixed with fresh inlet air flow, which is controlled by a modulating damper upstream of the fresh air/FGR mixing zone. A damper is installed in the FGR duct upstream of the mixing box to restrict the maximum FGR flow rate. This damper will typically be closed while the boiler enclosure is purged and open after the boiler enclosure purge is complete to allow the system to purge any combustibles in the FGR duct.

If the boiler is designed for a narrow NOx band of control across the boiler's whole operating range during steady state load demand, load changes, and excursions, the damper will act as a modulating control for the FGR flow. If the boiler is designed for a wide NOx band of control at all operating conditions, the FGR damper will remain in the pre-determined fixed position based on the NOx requirements at 100 % MCR.

For FGR boilers designed to have a modulating FGR damper, FGR damper movement will be allowed as long as the damper is being moved to a safer operating position (less open) relative to the curve generated during boiler commissioning or no more open than the limit determined during boiler commissioning.

The FGR damper position is set based on the actual boiler firing rate demand (or fuel gas flow) rather than the air demand. The valve position curve is specified during the boiler design phase of a project and confirmed during initial boiler commissioning.

When FGR is employed, the following considerations should be incorporated into the operating controls system.

a) The firing control strategy for a boiler designed for FGR operation should be configured to have a cross-limiting air-to-fuel ratio combustion control mechanism with O_2 trim.

b) Appropriate control schemes and methods for control curve development to establish the safe envelope for FGR operation is identified during field commissioning on the FGR boiler.

c) A safe envelope for burner operation should be maintained by controlling O_2 in the windbox, O_2 in the stack, FGR damper position, and fresh air damper position according to the curves that are established during commissioning.

Proper control of the air to flue gas ratio is critical. Too little flue gas for a given amount of air may result in insufficient NOx emissions reduction. Too much flue gas may result in flame instability due to oxygen depletion and/or excessive velocity. Too much flue gas may cause the flame envelope to impinge on the steam generator tubes.

In order for the external FGR strategy to work, precise control of the mixture of flue gas and air should be maintained by continuous measurement and control. This may be achieved by directly measuring the mass flow of the air and the flue gas (e.g. thermal mass flow sensors) or by measuring volumetric flows with pressure and temperature compensation.

A common method is to measure the resulting mixture of flue gas and air for the proper oxygen concentration directly using an oxygen analyzer. This eliminates the need to measure multiple variables in favor of one and provides a means of directly measuring the results of the air and flue gas mixture. However, the user should be advised that a typical ZrO_2 sensor may not work as well at higher O_2 levels. At higher O_2 levels, the mV output from the ZrO_2 cell is very small and not as accurate as it is with lower O_2 measurements typically found in the flue gas.

7.4.7 Final Control Element Assembly

7.4.7.1 Dynamic Performance

A certain level of quality of process control performance is required for every application. For boilers, the appropriate dynamic response of control element assemblies is required to ensure boiler performance requirements are met (e.g. band of control, ramp rate, low O_2 at turndown, etc.). Control element performance may be improved by narrowing the dead band, improving the resolution, minimizing overshoot, and decreasing both the dead time and the step response time.

With the exception of variable speed drive controls, each final control element assembly includes the following components (as required): valve/damper/vane, actuator, positioner, I/P transducers, filter/regulators, boosters, and solenoid valve. The dynamic performance of the final control element assembly is impacted by the design of each of these components. Each individual component should be designed to maintain the dynamic performance recommendations listed below for the expected life of the final control element with minimal maintenance.

Each final control element assembly should meet the following dynamic performance requirements:

a) speed of response, as defined in Table 14, for any step change in the range of 2 % to 10 % of full range;

b) dead band less than 0.5 % of full range;

c) step resolution less than 0.25 % of full range;

d) overshoot less than 5 %.

Table 14—Speed of Control Response

Final Control Element Assembly	Maximum Dead Time (Td) s	Maximum T63 Step Response Time s	Maximum T86 Step Response Time s
Variable speed drive assembly	0.5	1.0	1.5
Fuel control valve assembly	0.5	1.0	1.5
Damper or vane assembly	1.0	5.0	7.5

Actuator air supply line, connections, and tubing size shall be large enough to meet the specified dynamic performance or stroking time. Actuators with diaphragms larger than 968 cm^2 (150 $in.^2$) shall have at least a 13 mm (0.5 in.) actuator air connection.

The testing method and documentation should be mutually agreed upon between the final control element vendor and purchaser to determine compliance with these dynamic performance recommendations.

7.4.7.2 Fuel Control Valve Sizing and Mechanical Consideration

In general, the fuel flow control valves should be sized in accordance with the recommendations in API 553 (Section 4.1.19). A fuel control valve is typically selected with equal percent trim to provide improved control at low firing rates.

As a design guideline, the fuel gas header pressure should be set high enough to allow for 60 % of the pressure drop to be taken by the burner at normal firing rates, 7 % for line loss and flow measurement, and the remaining 33 % of the pressure drop for the control valve.

Valves should fail to the closed position on loss of instrument air.

7.4.7.3 Damper/Vane Sizing and Mechanical Considerations

7.4.7.3.1 Overview

In any duct-system design, the selection and location of the system's dampers/vanes should consider safety, maintenance, and process control needs and requirements. In short, each damper/vane application has its own unique set of requirements.

7.4.7.3.2 General Design Criteria

When selecting or specifying a damper, the following should be considered:

a) design pressure and design differential pressure;

b) design temperature;

c) design leakage rate;

d) application damper type, as discussed below;

e) mode of operation (manual, automatic, etc.);

f) local instrumentation (limit switches, positioners, etc.);

g) rate of operation;

h) materials of construction of blades, shafts, bearings, frame, etc.;

i) internal and or external insulation requirements;

j) fail position (e.g. fail close, fail open, fail last position, etc.).

Whenever possible, louver dampers should be used in place of variable inlet vane (VIV) dampers due to the mechanical disadvantage. VIVs are difficult to maintain due to various mechanical components and access problems. VIV blade overstroking due to mechanical looseness could lead to counter-swirl, excess power draw, and inefficiency at low operating conditions.

7.4.7.3.3 Leakage Design Criteria

Dampers can be classified into the following three (3) types based upon the amount of internal leakage across the closed damper at operating pressures.

Type 1: Tight shutoff Louver/butterfly—low leakage (less than 3 %).

a) Tight shutoff louver dampers may be of single blade or multi-blade construction. Leakage rates of 0.5 % or less of flow at operating conditions are achievable. However, 100 % (man-safe) isolation will require a seal fan system.

b) For Type 1 dampers that require tight shutoff, seals between both blades to frame and blade to blade are required.

c) Blade-to-frame end seals shall be designed to accommodate expansion and contraction of blades, to prevent the accumulation of particulate, and to minimize pressure drop-metallic jamb seals are most common.

d) Blade-to-blade seals shall be designed with proper overlap and be resilient enough to accommodate flow velocities at any blade position.

e) All damper seals shall be engineered in such a way as to allow easy removal and replacement in the event of damage or failure.

Type 2: Isolation guillotine.

a) Low-leak—leakage less than 1 % without seal air.

b) Zero-leak—zero leakage (man-safe) with seal air.

Isolation guillotines are used to isolate equipment either after a change to natural draft or when isolating one of several boilers served by a common preheat system. The design should consider exposure of personnel, the effects of leakage on boiler operation, the tightness of damper shutoff, and the location of the damper (close to or remote from the affected boiler). Isolation guillotine dampers are designed to have low internal leakage when closed and zero leakage if seal air system is used. Zero-leak or man-safe can be achieved by a guillotine with a seal air chamber with air purge or double-block-and-bleed design consisting of two dampers in series with an air purge between. Guillotines with an engineered matrix blade may have one side insulated to allow personnel to safely enter ductwork (downstream of the damper) during operation of connected equipment.

Type 3: Flow control or distribution: medium to high leakage approximately 5 % to 10 %.

Flow-control dampers/vanes are typically multi-blade louver type. An opposed blade configuration provides best flow distribution. Parallel-blade or single-blade dampers should not be applied where the flow-directing feature inherent in their design can impair fan performance or provide an unbalanced flow distribution. Actuation linkage for dampers used for control or tight shutoff should have a minimum number of parallel or series arms. The potential for asymmetrical blade movement and leakage increases with linkage complexity.

7.4.7.3.4 Miscellaneous Damper Requirements

Internal Refractory and External Insulation Systems—Externally insulated ducting can be desirable in relatively cool flue gas applications since it helps maintain higher casing metal temperatures, thus reducing the chance of dew point corrosion. Care should be taken when using external insulation to prevent interference with the moving parts of the damper such as blade shafts, linkages, etc. Care should also be taken such that upper temperature limits are not exceeded for any damper components. These of internal refractory should be kept consistent with the refractory used in the adjacent upstream and downstream ducting. Whenever possible, dampers with refractory linings should have flanged and gasketed duct connections. The refractory should be installed and dried-out at the factory prior to shipment and storage. Proper expansion allowances should be an integral part of the design to prevent interference or binding of components at elevated service temperatures.

Inspection and Testing—As a minimum, each damper should be sufficiently assembled and operated at ambient conditions through its full range of motion utilizing the actuator being provided to confirm proper blade seating and overall operation. Additional cross blade leakage testing or testing at design conditions is available upon customer request. Vendor should maintain records of the method of testing, results obtained, and any corrective action taken for future reference.

Painting and Preparation for Shipment—As a minimum, all specified surfaces should be painted with one coat 1.5 mils thick of manufactures standard high temp shop primer within 24 h of surface the preparation recommended by paint manufacture. Any machined surfaces should be coated with a rust inhibitor.

Dampers should ship completely assembled whenever possible. Actuators, etc. that can easily be damaged should be removed, match marked, and properly crated before shipping.

O & M Manual—O & M Manuals should include the manufacturer's operating and maintenance instructions for all damper components. Detailed instructions should include operating instructions, preventive maintenance instructions, special tools, recommended spare parts, emergency operating procedures and repairs, troubleshooting instructions, and a list of phone numbers and names of the local service representatives for all damper components. Standard manufacturer's catalog information is acceptable; the component manufacturer should supply any information not included in the standard catalog information.

7.4.7.4 Fan Controls

The fan may be controlled on the basis of inlet pressure, discharge pressure, flow rate, or some combination of these parameters. This may be accomplished by suction or discharge throttling or speed variation. The purchaser shall specify the type and source of the control signal, its sensitivity and range, and the equipment scope to be furnished by the vendor.

For constant-speed drive, the control signal shall actuate an operator that positions the inlet or outlet damper.

For a variable-speed drive, the control signal shall act to adjust the set point of the driver's speed control system. Unless otherwise specified, the control range shall be from the maximum continuous speed to 95 % of the minimum speed required for any specified operating case, or 70 % of the maximum continuous speed, whichever is lower (see 8.5).

NOTE When the application requires the motor to slow down more quickly than the inertia of the load will allow, dynamic braking resistors may be used to mitigate a high DC bus condition and a subsequent trip of the VFD. When driven by inertia, the motor becomes a generator that sends AC to the output terminals of the drive. Since the output semiconductors on the drive are bipolar in nature, they will rectify the AC to DC and place it on the DC bus. A continual rise in DC bus voltage will eventually cause the drive to trip as a protective measure. A potential solution is to order the drive with dynamic braking. This adds an output semiconductor to the drive. It will gate "ON" when the DC bus voltage reaches a specified value and shunt the excess power into an external dynamic brake resistor.

A common example is when the BMS transitions the combustion air blower from purge rate air flow to light-off conditions. If the system attempts to slow the blower too quickly, the inertia may trip the VFD. While extending the deceleration parameter (e.g. from 10 s to 30 s) may allow the drive to decelerate the load without generating excess voltage, dynamic braking resistors improve the capability of the VFD to match the rate of change in process demand without tripping the VFD.

The full range of the purchaser's specified control signal shall correspond to the required operating range of the driven equipment. Unless otherwise specified, the maximum control signal shall correspond to the maximum continuous speed or the maximum flow rate.

Unless otherwise specified, facilities shall be provided to automatically open or close (as specified) the dampers or variable-inlet vanes on loss of control signal and to automatically lock or brake the dampers or vanes in their last position on loss of motive force (such as air supply or electric power). This is a specific system consideration, and the associated controls shall be arranged to avoid creating hazardous or other undesirable conditions.

Unless otherwise specified, the fan vendor shall furnish and locate the operators, actuator linkages, and operating shafts for remote control of the dampers or variable-inlet vanes. Operator output shall be adequate for the complete range of damper or variable-inlet vane positions. The proposed location of operator linkages and shafts shall be reviewed with the purchaser for consideration of maintenance access and safety.

External (i.e. local) position indicators shall be provided for all dampers or variable-inlet vanes.

Unless otherwise specified, pneumatic activators shall be mechanically suitable for an air gauge pressure of 860 kPa (125 psi) and shall provide the required output with an air gauge pressure as low as 410 kPa (60 psi).

7.5 Protective Systems

7.5.1 General

The purpose of protective systems is to maintain safe operation or to achieve safe state in response to unacceptable process deviations.

Protective actions include the following.

a) CCS Action—control overrides independent of the initiating cause, and CCS to BMS trip (see 7.2.3.14).

b) Operator Action—operator response to alarms, including emergency response.

c) BMS Action—start-up permissives and interlocks, close SSVs, open dampers.

Protective functions include the following components.

a) Input Devices—process measurements (e.g. analytical sensors, analog transmitters, or discrete switches), manual input devices (e.g. hard or soft hand switches/pushbuttons), and status indications (e.g. position transmitters or limit switches).

b) Logic Solver—programmable electronic systems, hardwired relays, solid state systems.

c) Output Devices—interface to final elements (e.g. solenoid or relay), final elements (e.g. SSVs, combustion air dampers, stack damper, pumps, etc.), and alarm/status indicators [e.g. panel lights, or human machine interface (HMI) display graphics].

7.5.2 General Considerations

7.5.2.1 General

The diversity in the design of boilers requires that each boiler be independently evaluated to ensure that each hazard scenario is effectively mitigated. In addition to combustion hazards, the mechanical integrity of the steam generator and downstream components, such as outlet piping and superheaters, may be an important safety consideration. Since each boiler may have unique features or operational modes, it is critically important that those responsible for assessing the availability and reliability of a protective function understand all of the possible equipment failure modes and the potential impact to the operating unit and personnel.

7.5.2.2 Protective Function Considerations

There are a diversity of issues that may impact the variables (e.g. set points, timers, etc.) associated with protective functions. Examples include:

a) operating temperature and pressure;

b) type and size of the boiler;

c) type and number of burners;

d) type and reliability of the igniters;

e) turndown requirements;

f) operating and safety criteria from the burner manufacturer;

g) variability in fuel gas composition and supply pressure;

h) fuel supply reliability and filtration requirements;

i) length and cross-sectional area of air ducts (velocity, turbulence, flow conditioning);

j) mechanical integrity of combustion air and flue gas dampers;

k) mechanical integrity of the preheater for low NOx burners;

l) location of taps for process measurement;

m) line size and pressure drop in the fuel gas manifold to the burners;

n) redundancy requirements for availability and reliability;

o) scheduled outage or turnaround intervals;

p) winterization and insulation requirements in cold climates;

q) applicable federal, state, and local regulations.

7.5.2.3 Protective System Considerations

Additional considerations for protective systems include the following.

a) Operational Modes—Consideration must be given to all equipment modes of operation (e.g. start-up, steam production change, minimum firing and shutdown operations, standby mode with quick start capability) to ensure there is adequate protection in all of these modes.

b) Independence—It is recommended practice to maintain separation between the control and protective systems. For example, a control device that malfunctions to create an unacceptable process deviation is no longer available to detect or mitigate the process hazard it has created.

c) Reliable Power Source—It is recommended that all protective instrumentation be sourced from a reliable power source, e.g. UPS per API 554.

d) Loss of Utility—When loss of electrical power or instrument air occurs, it is essential that the final elements are designed to fail-safe. For example, solenoids should be de-energized to trip and the springs in SSVs and dampers should fail in the direction required to achieve safe state.

e) System Reset—Once activated, the BMS should keep the process in the safe state until the unsafe condition is corrected and the BMS is manually reset.

f) Event Logging—It is recommended that protective systems be implemented with alarm/logging systems capable of capturing first out and sequence of events alarms.

g) Alarm Rationale—It is recommended that an alarm rationale be performed to prioritize and minimize the number of actionable alarms in an emergency.

7.5.2.4 Protective vs Safety Instrumented Function

A PIF may be applied to the water side (steam) and the combustion side of boilers. PIFs are implemented to detect hazardous conditions and either achieve or maintain a safe state. When a PIF is implemented to prevent a hazardous event that could result in personnel injury or fatality, the PIF is classified as a SIF if a SIL is assigned.

A SIF assigned a SIL of 1, 2, or 3 shall comply with the requirements of ANSI/ISA 84.00.01-2004 (IEC 61511-1 Mod). Although this standard is accepted good engineering practice and is recommended for the protection of personnel and the environment, the work process may be applied to asset protection. While these PIFs may have an assigned integrity level (IL) they should be clearly identified as non-safety applications.

7.5.3 Response Time Considerations

7.5.3.1 General

Each protective function has a maximum permissible time for corrective action to mitigate a hazardous event.

7.5.3.2 Process Safety Time

Process safety time is the interval between the initiating event leading to an unacceptable process deviation and the hazardous event.

7.5.3.3 Process Response Time

Process response time (dead time, delay time, or lag time) is the time required for a process variable to start changing after an initiating event.

For example, the extent of a change in the air/fuel ratio may not be fully detectable by an oxygen analyzer for several tens of seconds (e.g. 10 s to 20 s) even if the oxygen measurement between the combustion chamber and economizer is instantaneous.

There may also be process response time between corrective action to safe state and the time at which safe state is achieved.

7.5.3.4 Measurement Lag Time

Measurement lag time is the time required for an instrument to provide feedback to the control or safety system in response to a change in a process variable.

Measurement lag times are typically associated with temperature and analytical measurements.

The response times for analytical measurements are frequently represented as a percent of final value to a process step change. For example, T90 < 10 s represents a sensor response to 90 % final value of the process deviation in less than 10 s.

7.5.3.5 Time Delays

Input time delays are frequently implemented to minimize spurious trips caused by transient conditions that do not create a process hazard. Due to the fast scan capability of PLCs and other logic solvers, small variations or short-term process impulses may be detected that may yield a spurious trip when hazardous conditions are not present. Therefore, an input time delay of 0.5 s to 1.0 s is frequently implemented as an input filter.

Delay trip timers may be used to confirm the presence of a hazardous condition for a sustained period prior to activating a trip; however, a thorough knowledge of the process safety time and time to safe state is required.

7.5.3.6 Time to Safe State

Time to safe state is the time difference between alarm or trip set point activation and the time required to achieve a safe state. Set points should be selected to detect the unacceptable process deviation as early as possible in the process hazard timeline. For a protective function to be effective, safe state must be achieved within the process safety time.

a) For operator response to an alarm, this includes diagnosis time, field travel time, corrective action time, and the process response time to achieve safe state.

b) For an automated protective function, this includes delay trip timers in the logic solver, stroke time for SSV(s) or dampers, and the process response time to achieve safe state.

7.5.3.7 Operator Response to Alarms

Alarms may be configured to notify the operator of abnormal process conditions, allowing the operator to take corrective action prior to an automated response by the safety shutdown system.

a) The basis for alarm set points, the correct operator actions in response to the alarms, and the response time requirements to safe state should be documented during the design phase.

b) Alarms that do not have a clear operator response should be avoided. It is important to identify which alarms require immediate response to assign them an appropriate priority.

c) The operator response to each critical alarm (e.g. high priority or managed alarm) should be defined in the process unit's operating procedures.

7.5.4 Terminology—Key Words and Phrases

7.5.4.1 General

Within the refining and petrochemical industry, certain words and phrases (e.g. override, inhibit, bypass) are loosely defined causing confusion. The following clarifies the intent with the scope of this document.

7.5.4.2 Start-up Overrides

A start-up override is an automated bypass of a start-up trip condition. Devices that are automatically overridden by the BMS logic at a specific point in the start-up sequence are typically returned to service (i.e. latched or activated) after a specified time interval.

As an example, when the low fuel gas pressure trip is located downstream of the fuel gas block valves, a start-up override is required to permit opening of the fuel gas block valves. After the fuel gas block valves are commanded open, the low fuel gas burner pressure trip should be armed within a specified time interval (e.g. <10 s) not to exceed the TFI timer.

Where required for start-up sequencing, start-up overrides shall be designed as part of the BMS logic.

7.5.4.3 Control Overrides

A control override does not bypass a protective function. Instead, a control override is designed to keep the boiler within operational limits and prevent a spurious trip (where applicable). A control override permits one controller to take control of the signal output from another controller. The output from two or more controllers is typically combined into a high or low selector, and the output from the selector controls the signal output to the final element.

a) As an example, suppose the fuel gas controller is in flow control mode. A fuel gas pressure controller may be configured to monitor the burner pressure. At the low (or high) set point limit, the pressure controller may override the flow controller to keep the boiler in a safe operating region and prevent a spurious trip on low (or high) burner pressure. Once the burner pressure is within the set point limits of the pressure controller, control is automatically returned to the flow controller via the high or low selector.

b) Consider a counter to track how frequently a control override is invoked.

7.5.4.4 Controller Limits

A set point or output limit(s) are configurable options at the controller to keep the boiler within operational limits and prevent a trip (where applicable).

a) As an example, if the fuel gas controller is in pressure control mode, limits may be configured in the pressure controller to prevent a spurious trip on low (or high) burner pressure. Although generally referred to as a control override, the controller output is not externally controlled via a high or low selector. Instead, a soft clamp is configured into the controller.

b) Set point or output limits are not typically annunciated at the operator interface.

7.5.4.5 Bypasses

A bypass refers to a manually initiated action to bypass the input device(s) of a protective function and typically involves a keyed bypass or other manual initiation. A protective function that is bypassed is not available to trip until the bypass is manually removed and the protective function is returned to service.

a) During normal operation, bypassing an input measurement device temporarily for maintenance, calibration, and testing is permissible where governed by trained personnel, applicable maintenance and operating procedures, and any emergency response procedures to the measurement under bypass. The associated control system alarm for the measured process variable cannot be bypassed at the same time as the protective device.

b) Bypass alarm and status indications should be provided to the operator interface.

c) It is recommended that a start-up bypass is managed via a start-up override.

7.5.4.6 Permissives

Permissives are conditions that must be satisfied to progress to the next step in a sequence.

a) As an example, fuel gas header pressure above a minimum light-off pressure may be a permissive to open the igniter gas and/or fuel gas SSVs. Once the sequence has progressed to the next step, a permissive does not typically initiate a trip. For example, fuel gas header pressure (not burner pressure) may fall below permissive limits with no trip action once the igniters and/or burners are in service. At this point in the sequence, low fuel gas header pressure would typically alarm only (i.e. if the low-pressure trip is monitored at the burner manifold, see 7.5.5.6.2).

b) The status of permissives is typically indicated at the operator interface.

7.5.5 Combustion Process Hazards Protection

7.5.5.1 General

Clarifications to protective functions prescribed in NFPA 85 are provided below. These protective functions consist of a measurement and an action, usually operating valves, dampers, or motors. Each process deviation lists the process hazard, considerations, control overrides, alarms, and protective functions.

In each case consideration should be given in regards to the redundancy required, both from an availability and reliability perspective. Accessibility to maintain and test online should also be reviewed. For redundant process measurements, process tap locations and potential for common mode failure due compromised measurement should be evaluated.

7.5.5.2 Accumulation of Combustibles (Loss of Flame or Substoichiometric Combustion)

7.5.5.2.1 Process Hazards

Loss of flame or substoichiometric combustion may lead to the accumulation of combustibles within the boiler.

Potential hazardous events include the following:

a) afterburning in the furnace, which may result in the overheating and failure of tubes and/or tube supports systems;

b) an explosion, which may result in the partial or total destruction of the boiler and may be hazardous to personnel in the operating area.

These hazardous events may develop if the following occur:

a) combustibles accumulate in the boiler;

b) oxygen is either present prior to the accumulation of combustibles or oxygen is reintroduced after the accumulation of combustibles;

c) sufficient time passes to allow the combustibles and oxygen to meet and mix and thereby reach a flammable mixture condition;

d) the flammable mixture is either hot enough to auto-ignite or it encounters an ignition source such as a section of hot refractory, a heated analyzer sensor/cell, an operating igniter, or an operating burner.

7.5.5.2.2 Considerations

The hazard associated with a specific concentration of combustibles in the boiler mixing with fresh air and igniting may be estimated using thermodynamic calculations. The severity level posed by such an event depends on the amount of energy released as pressure [9].

a) At start-up conditions, the accumulation of combustibles within the boiler should not be permitted to exceed 25 % of the LEL before corrective action is initiated. The LEL may be calculated at laboratory conditions using Le Chatelier's formula and LEL data for pure components as listed in NFPA 325, 1994 Edition. Recently unlisted, the full text of NFPA 325 is now included within the 13th edition of NFPA's *Fire Protection Guide to Hazardous Materials*.

b) At operating conditions it is possible for a boiler to accumulate combustibles at temperatures above the auto-ignition temperature if there is insufficient air to consume all of the fuel. Fuel-rich combustion produces hot flue gas with residual combustibles that can explode if mixed with fresh air too quickly. This is most likely to occur when a boiler transitions suddenly from rich combustion to lean combustion [9].

Process deviations that precede flameout are typically associated with operational limits. Approaching or exceeding operational limits can lead to rapid accumulation of combustibles within the boiler. For example, loss of flame may result in the rapid accumulation of combustibles to an unacceptable hazard level within 5 s to 10 s. Process deviations that precede flame out include:

a) low combustion air flow or loss of FD fan (see 7.5.5.3),

b) low furnace pressure (see 7.5.5.4),

c) high furnace pressure (see 7.5.5.5),

d) low fuel gas burner pressure (see 7.5.5.6),

e) high fuel gas burner pressure (see 7.5.5.7),

f) low instrument air pressure (see 7.2.3.13),

g) rapid change in fuel composition with uncompensated fuel flow (see 7.3.5),

h) slug of liquid in fuel gas system that causes loss of flame.

Process deviations that occur within operating limits may lead to a more gradual accumulation of combustibles (CO, hydrogen, or hydrocarbon). These process deviations include:

a) an increase in fuel gas flow rate to the burners without a corresponding increase in combustion air flow rate to the burners,

b) a decrease in a combustion air flow rate without a corresponding decrease in fuel gas flow to the burners,

c) burner tip plugging in one or more burners,

d) partially closing a block valve on a fuel line to an individual burner,

e) partially closing or fully closing the air register on an individual burner,

f) changes in ambient air conditions,

g) changes in fuel gas composition,

h) too much external FGR (where applicable).

Excessively fuel-lean combustion with a low combustion chamber temperature may lead to gradual accumulation of combustibles within the combustion chamber.

7.5.5.2.3 Control Overrides

Consider the following additional control overrides to keep the boiler within operational limits and prevent a spurious trip (where applicable).

a) Low oxygen override to the fuel gas controller (see 7.5.5.9.3).

b) Low furnace pressure override (see 7.5.5.4.3).

c) High furnace pressure override (see 7.5.5.5.3).

d) Low fuel gas burner pressure override to the fuel gas controller (see 7.5.5.6.3).

e) High fuel gas burner pressure override to the fuel gas controller (see 7.5.5.7.3).

f) High combustibles override to the fuel gas controller. The combustibles measurement may be used as an override variable to increase combustion airflow if combustibles levels are below a specified threshold (e.g. <500 ppmvd). Above that specified threshold, fuel should be reduced until excess air is restored to safe operating levels as confirmed by the oxygen analyzer.

g) A design consideration is to limit the rate of change of fuel flow and air flow such that a process step change may be detected within the overall response time of the control loop. For example, an oxygen analyzer located between the combustion chamber and economizer may have an inherent process delay on the order of 10 s to 20 s to T90.

To be effective, control overrides should:

a) be independent of the initiating cause (e.g. control loop malfunction) of the hazard scenario,

b) operate continuously in response to the process deviation creating the hazard scenario.

7.5.5.2.4 Alarms

Alarms may be set to alert operators to abnormal process conditions approaching operational limits that may lead to rapid accumulation of combustibles within the boiler. The alarms may be triggered by the following:

a) low combustion air flow (see 7.5.5.3.4),

b) low furnace pressure (see 7.5.5.4.4),

c) high furnace pressure (see 7.5.5.5.4),

d) low fuel gas burner pressure (see 7.5.5.6.4),

e) high fuel gas burner pressure (see 7.5.5.7.4),

f) low instrument air pressure (see 7.2.3.13),

g) high liquid level in an upstream fuel gas knockout drum.

Alarms may be set to alert operators to abnormal process conditions that occur within operational limits and that may indicate substoichiometric combustion or lead to a more gradual accumulation of combustibles. The alarms may be triggered by the following:

a) low or high air-to-fuel ratio,

b) low oxygen (see 7.5.5.9),

c) high CO/combustibles.

7.5.5.2.5 Protective Functions—Rapid Accumulation of Combustibles

For the rapid accumulation scenario, protective functions may be divided into BMS actions prior to loss of flame and BMS actions upon loss of flame as noted below.

To mitigate process deviations at operational limits that precede flameout, close the appropriate SSVs in response to:

a) low combustion air flow or loss of blower (see 7.5.5.3);

b) low furnace pressure (where applicable, see 7.5.5.4) per vendor recommendation;

c) high furnace pressure (see 7.5.5.5);

d) low fuel gas burner pressure (see 7.5.5.6);

e) high fuel gas burner pressure (see 7.5.5.7);

f) low instrument air pressure (where applicable, see 7.2.3.13);

g) high liquid level in an upstream fuel gas drum (optional).

NOTE The basis for tripping in response to process deviations that precede flameout is to prevent a rapid accumulation scenario. Once a rapid accumulation event is initiated, it may be challenging to achieve safe state within the process safety time.

In response to loss of flame detection, take the following corrective action.

a) For single burner boilers, close the SSVs.

b) For two burner boilers, follow the boiler manufacturer's instructions. In the absence of specific instructions use the following guidelines.

   1) When fuel is in pressure control mode, and air flow to each burner is independently measured and controlled, close the SSV(s) to the burner where flame detection has been lost.

   2) When fuel is in flow control mode, and air flow to each burner is independently measured and controlled, the controller shall automatically reduce the fuel flow in half and close the SSV(s) to the burner where flame detection has been lost.

   3) If air flow is not independently measured and controlled to each burner, upon loss of flame at one burner, close the SSVs to that burner and place fuel flow and air flow in manual so that the total fuel to the burner that is remaining in operation does not increase and airflow does not decrease. Slowly close the burner damper/register to the non-operating burner. Once the burner register on the non-operating burner is closed, it is permitted to adjust the airflow and fuel flow to the remaining burner within the burner operating limits.

c) For multiple burner boilers (more than two burners), close the SSVs to the burner where flame detection has been lost. Slowly close the burner damper/register to the non-operating burner if needed to maintain the proper air-fuel ratio at the operating burners.

   1) Partial Loss of Flame Introducing Hazard—A partial loss of flame predetermined to be likely to introduce a hazardous accumulation of unburned fuel shall activate the MFT.

   2) Automatic Switching to Manual Mode when Tripping an Individual Burner—A design consideration when closing a SSV to an individual burner (upon loss of flame) is for the BMS to notify the CCS to automatically switch the fuel gas controller to manual mode in an attempt to maintain a constant air/fuel ratio at the online burners until the operator can intervene. Otherwise, the heat lost from the offline burner will automatically increase the fuel demand to further degrade the air/fuel ratio at the online burners.

For all boilers, a MFT is initiated upon loss of all flame and a post-purge of the boiler is completed. Fans may be shut down following the post-purge.

7.5.5.2.6 Operator Response to Fuel-rich Combustion—Gradual Accumulation of Combustibles

Consider the following in response to process deviations that occur within operational limits that may lead to substoichiometric combustion and a gradual accumulation of combustibles within the combustion chamber.

As long as combustion is sustained, operators should clear the area of personnel and slowly reduce fuel gas flow or external FGR (where applicable) to avoid a hazardous situation. For example, if an operator responds to a fuel-rich furnace by completely shutting off the fuel (e.g. via the ESD pushbutton) then fresh air will mix with the combustibles inside the combustion chamber and may ignite. Even a sudden change from 90 % air to 110 % air (10 % excess air) could be too much for the boiler to follow safely. An understanding of the residence time is helpful to establish a safe ramp rate [9].

This is a consideration only where operators are trained to recognize the signs of substoichiometric combustion such as:

a) alarms,

b) a huffing sound associated with pressure pulsations in the boiler,

c) elevated convection section or stack temperatures due to afterburning,

d) smoke in flue gas leaving the stack,

e) smell of unburned fuel.

Potential Advantage—This option reduces the number of times a boiler is shut down in response to substoichiometric combustion. Some facilities have operating experience to indicate that explosions are more likely to occur during light-off, due to inadequate purge or delayed ignition, than during substoichiometric combustion. For those facilities, reducing the number of restarts may be an important consideration.

Potential Disadvantage—The sequence of events may progress more quickly, from substoichiometric combustion to loss of flame, than the operator can effectively manage. Additional considerations in a fuel-rich environment include removing potential ignition sources (e.g. continuous igniters and analyzer sensor power).

7.5.5.3 Low Combustion Air Flow

7.5.5.3.1 Process Hazard

Combustion air flow below that needed for stable flame operation may lead to the accumulation of CO or hydrocarbon within the boiler. See 7.5.5.2 for a description of the hazardous events that may occur.

7.5.5.3.2 Considerations

This section is intended to apply to boilers equipped with FD fans.

a) For multi-burner boilers, the NFPA 85 committee set a minimum purge limit of 25 % MCR airflow to resolve insufficient purge-based explosions in the 1960s. With improvements in airflow measurement technology, the prescriptive requirement to maintain 25 % MCR airflow presents a problem for the refining and petrochemical industry with requirements run an N+1 boiler on standby. As a result, many refineries run the igniter in standby mode and elevate the airflow to 25 % MCR airflow prior to lighting the main burner.

b) The low combustion air flow alarm and trip set points should be set as follows.

   i) Single Burner Boilers—For single burner boilers, airflow demand shall not be reduced below the low limit of the fuel-burning system as determined by the burner manufacturer and verified by operating test. Within the refining and petrochemical industry, this is typically associated with the minimum airflow required to complete combustion at the burner's minimum heat release from the burner curve.

   ii) Multiple Burner Boilers—The low combustion airflow trip should be set at 20 % of the design full load mass airflow (see 7.2.3.12)

c) Where airflow measurement is not practical for existing air duct designs, air duct pressure measurement (see 7.3.3.3) is an option downstream of dampers and preheaters.

   NOTE Airflow measurement with sufficient turndown (see 7.3.4.1 and 7.3.4.5) is recommended for new boilers.

d) Monitoring FD fan motor run status, motor power, or motor amps is frequently used as a leading indicator of loss of combustion air. Response time is improved by taking corrective action on loss of fan instead of waiting for the low flow trip set point.

e) For fully metered CCS, air/fuel ratio cross-limiting control is assumed for boilers (i.e. when in automatic mode).

7.5.5.3.3 Control Overrides

To keep the boiler within operational limits and prevent a nuisance trip, consider implementing a low oxygen override to the fuel gas controller (see 7.5.5.9.3). This may be accomplished by reducing the fuel gas firing rate at low oxygen conditions to keep the flue gas above the minimum desired oxygen concentration.

7.5.5.3.4 Alarms

The following alarms should be included to alert operators prior to a low combustion air flow trip of the SSVs:

a) low combustion air flow;

b) low air duct pressure (if measured downstream of dampers and APHs, see 7.3.3.3);

c) low FD fan speed (if measured);

d) high fan vibration (if measured);

e) high motor amps (if measured).

7.5.5.3.5 Protective Functions

See the following for low combustion air protective function requirements.

a) The SSVs should be closed at the low combustion air flow trip set point.

b) For boilers with a single FD fan, the SSVs should be closed upon loss of FD fan (e.g. via loss of run status).

c) The low combustion air flow trip set point shall be set to precede flameout when the burner is firing at turndown.

7.5.5.4 Low Furnace Pressure

7.5.5.4.1 Process Hazards

The furnace structure is typically designed to withstand a negative transient design pressure equal to the test block capability of the ID fan (i.e. up to –35 in. water) without permanent deformation due to yield or buckling of any support member.

Where the operating pressure has the potential to exceed the negative transient design pressure (e.g. during flame collapse from a MFT), this may result in furnace and/or ductwork implosion.

7.5.5.4.2 Considerations

The following are low furnace pressure considerations.

a) Boilers with both induced and FD fans may become unbalanced if the FD unit becomes tripped and the induced fan unit remains in full operation. When the ID fan is capable of producing more suction head than the boiler structure is capable of withstanding, this increases the likelihood of a furnace implosion.

b) MFT results in a rapid temperature decay inside the furnace. When coupled with an ID fan, this can create the hazard.

c) When an MFT occurs, the event occurs very rapidly. There is insufficient process safety time for operator response to alarm.

d) Low furnace pressure is more of a concern when the furnace volume is large and the ID fan is large relative to the furnace surface area. This is rarely a concern on boilers typically used in the oil refinery and petrochemical industry.

e) Low furnace pressure in a boiler is normally a concern on start-up and low fire conditions. With boilers having an exhaust stack of sufficient height >23 m (>75 ft) to generate a negative pressure in the furnace, a draft damper may be needed to manage the furnace pressure. Not managing the furnace pressure may result in an unstable flame condition at low loads and light-off of the burner. A low furnace pressure interlock can be used to prevent an unstable light-off condition.

f) Consider designing the furnace to withstand the head of the ID fan.

g) Consider designing the boiler structure to withstand a negative transient pressure of –35 in. of water column.

NOTE D fans in this service are not typically designed for more than –35 in. of water column.

h) The transient internal design pressures should be taken into consideration in the design of the airflow and gas flow path from the FD fan discharge through the stack.

i) Where a furnace pressure control protection subsystem (implosion protection) is installed:

— a typical method for preventing or minimizing furnace pressure excursions is to apply fan override action. Often used in conjunction with this fan override action is directional blocking, which prevents the furnace pressure regulating control element(s) from moving in a direction that would aggravate an existing furnace pressure error [NPFA 85 (2011), A.6.5.2.2.1(4)];

— the operating speed of the furnace pressure control elements shall not exceed the control system's sensing and positioning capabilities. Excessive speed can cause undesirable hunting and overshooting of automatic controls and create damaging negative pressure transients downstream. Excessive speed also might be unsuitable for manual control. Where variable speed or axial fans are used, the rate of response is slower than with constant speed centrifugal fans, and special consideration shall be given to the design of the furnace draft control system to ensure a satisfactory rate of response [NPFA 85 (2011), A.6.5.2.3(1)].

7.5.5.4.3 Control Overrides

Consider implementing overrides for low furnace pressure in the following order to keep the boiler within operational limits:

a) partially close the ID fan damper or reduce the ID fan speed (VFD),

b) partially open the FD fan damper or increase the FD fan speed (VFD).

7.5.5.4.4 Alarms

Where applicable, a low furnace pressure alarm should be included to alert operators of an unstable light-off condition.

7.5.5.4.5 Protective Functions

FD Systems—Implosion protection requirements shall not apply to units without a fan located in the flue gas path downstream of the boiler enclosure.

Balanced Draft Systems—Upon MFT, the BMS should send a feedforward (i.e. directional blocking) signal to the furnace pressure control protection subsystem (i.e. where installed) to prevent a furnace pressure excursion due to flame collapse from exceeding the negative transient design pressure.

7.5.5.5 High Furnace Pressure

7.5.5.5.1 Process Hazards

The furnace structure is typically designed to withstand a positive transient design pressure equal to the test block capability of the FD fan (i.e. up to +35 in. water) without permanent deformation due to yield or buckling of any support member.

Where the operating pressure has the potential to exceed the positive transient design pressure (e.g. tube rupture), this may result in yield or buckling of the furnace structure and/or ductwork.

Additionally, high furnace pressure can restrict the amount of air flow getting into the boiler. Under certain conditions, a fuel-rich condition can be created.

7.5.5.5.2 Considerations

The following are high furnace pressure considerations.

a) A cause of high furnace pressure is a tube rupture.

b) High furnace pressure override, alarm and trip are set significantly below the pressure required to impact boiler structural integrity.

c) Low emissions and or low NOx burners have a narrower band of control than high intensity burners and are subsequently more sensitive to air excursions created by high furnace pressure.

d) A stack damper minimum stop or an annular gap around the damper is used to avoid a condition where the damper is fully closed and potentially stuck closed. This also minimizes the potential for reaching a low draft condition. The minimum stop setting depends on fuel, boiler type, stack diameter, and type of damper.

    1) Typical constraints are in the 10 % to 25 % range.

2) The constraint can be configured in the control system, applied as a hard minimum stop at the damper or by physically trimming off some of the damper blade. Care must be taken to ensure damper balance is not negatively impacted.

e) Monitoring ID fan motor run status, motor power, or motor amps is frequently used as a leading indicator of high furnace pressure. Response time is improved by taking corrective action on loss of fan instead of waiting for the high furnace pressure trip set point.

f) If an ID fan is present, the boiler is assumed to be operating in furnace pressure control.

g) Consider designing the furnace to withstand the head of the FD fan.

h) Consider designing the boiler structure to withstand a positive transient pressure of +35 in. of water column.

NOTE FD fans in this service are not typically designed for more than +35 in. of water column.

i) Furnace design pressure greater than +35 in. of water column could result in a more severe energy release of the furnace enclosure if a fuel explosion occurs [NFPA 85 (2011), A.6.5.1.3.2.1].

j) The transient internal design pressures should be taken into consideration in the design of the airflow and gas flow path from the FD fan discharge through the stack.

7.5.5.5.3 Control Overrides

Consider implementing overrides for high furnace pressure in the following order to keep the boiler within operational limits and prevent a spurious trip:

a) partially open ID fan damper or increase the ID fan speed (VFD),

b) partially open stack damper (where applicable).

7.5.5.5.4 Alarms

A high furnace pressure alarm is recommended.

For balanced draft boilers, due to a potential for difficulty in measurement (i.e. noisy signals) and/or control (i.e. damper condition or tuning), a 1 s to 3 s time delay filter configured in the BPCS or safety system (not at the transmitter) may be considered.

For balanced draft boilers, the following alarms are recommended:

a) low ID fan speed (if measured),

b) high fan vibration (if measured),

c) high motor amps (if measured),

d) high ID fan inlet temperature.

7.5.5.5.5 Protective Functions

FD Systems—When furnace pressure exceeds the trip set point (typically specified by the boiler manufacturer), a MFT shall be initiated.

Balanced Draft Systems—Upon loss of ID fan or high furnace pressure, the stack damper may be fully opened (where applicable). If either the stack damper fails to open or the furnace pressure is not relieved within time constraints, a MFT shall be initiated.

7.5.5.6 Low Fuel Gas Burner Pressure

7.5.5.6.1 Process Hazard

Fuel gas burner pressure below that needed for stable flame operation may lead to the accumulation of combustibles (CO or hydrocarbon) within the boiler. See 7.5.5.2 for a description of the hazardous events that may occur.

7.5.5.6.2 Considerations

The following are low fuel gas burner considerations.

a) The low-pressure trip set point should be determined based on burner test data for the expected range of fuel gas compositions, combustion air temperatures, furnace temperatures and air-to-fuel ratios. Alternatively, the low-pressure trip setting may be based on the burner manufacturer’s heat release curve.

b) Main fuel gas control valve (MFGCV) should have enough turndown capability to allow stable start-up without venting to the atmosphere.

c) Throttling gas cocks should be avoided. It effectively defeats the low-pressure trip and increases the probability of creating the stated process hazard.

d) Without the Class 3 igniter flame, an input time filter on the order of 0.5 s may be acceptable in order to minimize the number of spurious trips caused by a transient drop in fuel gas pressure below the low fuel gas pressure trip set point. At low firing rate conditions, there may be barely enough heat in the tile or other components to relight the burners once they flame out. Re-ignition may not occur if burner components are allowed to cool for more than 0.5 s.

e) When Class 1 or Class 2 igniters are lit, a delay trip timer on the order of 3 s to 5 s may be acceptable to minimize spurious trips caused by a momentary drop in fuel gas burner pressure below the trip set point. This is particularly useful when sequencing in main burners during start-up at minimum fire. Additionally, the delay trip timer should be short enough that igniters relight the burners without causing a significant pressure wave inside the furnace with delayed ignition.

f) It is typically recommended to monitor both the low and high burner pressure trips with the same sensor(s) downstream of the fuel gas control valve. However, this is a function of the minimum operating burner pressure at burner turndown. When the minimum operating burner pressure range is greater than 0.3 psig to 0.5 psig, burner pressure should be monitored downstream of the fuel gas control valve. However, when the minimum operating burner pressure range is less than 0.3 psig to 0.5 psig, industry practice is to monitor pressure upstream of the fuel gas control valve to minimize the opportunity for nuisance trips on low fuel gas burner pressure. It is important to recognize that when the upstream location is used for a low-pressure trip, the fuel gas control valve should have a minimum flow stop to prevent a valve malfunction closed from moving the fuel gas pressure at the burner below the burner’s operating envelope.

7.5.5.6.3 Control Overrides

Consider implementing a low fuel gas burner pressure override to the fuel gas pressure controller to keep the boiler within operational limits and prevent a spurious trip (where applicable). This may be accomplished by configuring an output or set point limit in the fuel gas pressure controller or a low-pressure override to the fuel gas flow controller.

7.5.5.6.4 Alarm

Low fuel gas burner pressure should be alarmed to alert operators prior to a trip of the fuel gas shutoff valves.

7.5.5.6.5 Protective Functions

The following are requirements for firebox and stack temperature protective functions.

a) The fuel gas shutoff valves shall be closed at the low fuel gas pressure trip set point.

b) The low fuel gas burner pressure trip set point shall be set to precede flameout.

c) For burners with independent fuel gas supplies, each supply shall be independently tripped at the respective low-pressure trip set point. Since the air-to-fuel ratio will increase when such a shutdown occurs, details of how the burner will perform when suddenly subjected to high excess air should be provided by the burner vendor or determined by prior burner testing.

d) When automatic trip of the main fuel gas SSVs occur, all waste fuels that require main fuel gas firing for stability shall also be automatically tripped.

7.5.5.7 High Fuel Gas Burner Pressure

7.5.5.7.1 Process Hazards

Fuel gas burner pressure above that needed for stable flame operation may lead to the accumulation of combustibles (CO or hydrocarbon) within the boiler. High fuel gas burner pressure may also lead to flame impingement on one or more tubes. See 7.5.5.2 for a description of the hazardous events that may occur.

7.5.5.7.2 Considerations

The high-pressure trip set point should be determined based on burner test data for the expected range of fuel gas compositions, combustion air temperatures, combustion chamber temperatures and air-to-fuel ratios. Alternatively, the high-pressure trip setting may be based on the burner manufacturer’s heat release curve.

Techniques for mitigating high fuel gas burner pressure may include:

a) using an upstream fuel gas header pressure controller with a high-pressure limit,

b) maximum travel stop on the fuel gas pressure control valve.

7.5.5.7.3 Control Overrides

To keep the boiler within operational limits and prevent a spurious trip (where applicable), a high fuel gas burner pressure override of the fuel gas pressure controller can be utilized. This may be accomplished by configuring an output or set point limit in the fuel gas pressure controller or a high-pressure override to the fuel gas flow controller.

7.5.5.7.4 Alarms

High fuel gas burner pressure should be alarmed to alert operators prior to a trip of the fuel gas shutoff valves.

7.5.5.7.5 Protective Functions

The following are requirements for high fuel gas burner pressure protective functions.

a) The SSVs shall be closed at the high fuel gas pressure trip set point.

b) The high fuel gas burner pressure trip set point shall be set to precede flameout.

c) For burners with independent fuel gas supplies, each supply shall be independently tripped at the respective high-pressure trip set point. Since the air-to-fuel ratio will increase when such a shutdown occurs, details of how the burner will perform when suddenly subjected to high excess air should be provided by the burner vendor or determined by prior burner testing.

d) When automatic trip of the main fuel gas SSVs occur, all waste fuels that require main fuel gas firing for stability shall also be automatically tripped.

7.5.5.8 Firebox and Stack Temperature

7.5.5.8.1 Process Hazards

A high combustion chamber temperature may indicate overall overfiring, localized overfiring, individual burner related issues, steam demand changes, etc. Operating with a high furnace temperature may eventually lead to decreased reliability.

A high stack flue gas temperature is indication of potential overfiring, reduced convective area heat transfer, afterburning, or a fire.

Although not a process hazard, a low stack flue gas temperature indicates abnormal operation and the potential for condensing acid corrosion in the stack over long periods of time.

Low stack temperature can create a problem when FGR is being used.

7.5.5.8.2 Considerations

Although not a process hazard, a low stack temperature indicates the potential for:

a) incomplete combustion,

b) corrosion of unlined stack,

c) ammonium sulfate/bisulfate salt formation on the selective catalytic reduction (SCR) catalyst,

d) damaging analyzer sensors/cells,

e) condensation and salt formation in sampling lines,

f) pitting and unbalancing ID fan blades,

g) fouling and corrosion of APH elements,

h) fouling and pitting of cold process tubes in the convection section,

i) stack damper corrosion,

j) acid condensing on nearby equipment,

k) visible plume formation.

A high stack temperature indicates potential for:

a) stack damper failure (oxidation, thermal expansion, and/or warping),

b) mechanical failure of stack,

c) weakening of unlined structure,

d) overheating of APH elements,

e) overheating of ID fan,

f) sintering of SCR catalyst.

Firebox temperature is controlled during boiler start-up. This temperature is inferred through measurements of one or more of the following the boiler steam pressure, water temperature, and boiler exit temperature. The intent is to regulate the heat-up rate of the boiler metal during start-up.

Saturated boiler water temperature, drum pressure, and boiler exit temperature give the operator a good profile of internal metal temperature and the heat-up rate to be managed. If superheated steam coils are present, steam flow through the superheater tubes needs to be controlled. With a superheated boiler, overfiring the boiler during start-up can damage the superheater tubes as they are cooled by steam flow; at low loads there may be little if no flow.

To ensure the superheater has steam flow, the vents and drains are managed during start-up to force steam flow through the superheater, and the firing rate is managed to minimize the overheating of the superheater tubes. To assist the operator in the heat-up process, the additional temperature monitoring may be used. Flue gas temperatures before the superheater section and after the superheater tube banks can assist the operator in managing the burner-firing rate.

7.5.5.8.3 Control Overrides

Not applicable.

7.5.5.8.4 Alarms

A high furnace temperature alarm is recommended.

A high temperature alarm is recommended in the stack to warn against high stack flue gas temperature.

A low stack flue gas temperature trend display should be considered to warn of acid dew point condensation. An alarm could be configured to alert the operator if this condition exists for a longer period of time.

7.5.5.8.5 Protective Functions

No protective functions are recommended.

7.5.5.9 Low Oxygen

7.5.5.9.1 Process Hazard

Low oxygen in the flue gas may be an indication that combustion air flow is below that needed for stable flame operation, which in turn may lead to the accumulation of combustibles (CO or hydrocarbon) within the boiler. See 7.5.5.2 for a description of the hazardous events that may occur.

7.5.5.9.2 Considerations

The following are low oxygen considerations.

a) Combustibles breakthrough testing is recommended to establish oxygen concentration when combustibles breakthrough occurs.

b) For a positive pressure boiler, the breakthrough point typically occurs between 0.5 % to 1.5 % oxygen depending on the condition of the burners, the fuel gas composition and the furnace temperature, and the appropriate response (manual or automated) when combustion chamber conditions are unacceptable, i.e. high levels of CO and/or combustibles.

c) The operating margin between the $\%O_2$ set point and breakthrough must be sufficient to allow a process step change to be detected within the overall response time of the control loop.

d) Boilers should be operated at a $\%O_2$ set point that provides sufficient operating margin above combustibles breakthrough to accommodate anticipated changes in fuel gas composition.

e) The safe operating margin for $\%O_2$ above combustibles breakthrough is directly related to the control infrastructure.

f) Once flameout at one or more burners occurs, the oxygen indication will eventually rise. At this point, a low oxygen alarm is ineffective at detecting combustion problems.

g) In a properly designed system with fast response infrared or laser based O_2/CO measurements, oxygen control at less than 1 % may be acceptable (see 7.3.6.4). The final control elements (e.g. stack dampers, automated burner registers, and/or combustion air dampers) must have sufficient accuracy, turndown, and repeatability to keep the boiler in a safe operating region.

h) Fuel and air dampers on multi-stage or low emissions, low NOx burners are not advised to be operated in manual mode. These burners are operating with little room for variance on fuel-to-air ratio. By taking the fuel and air to manual operation, the boiler operator has little to assist in the determination of what is correct valve or damper position. Low emissions burners do not have a well-defined flame, and most boilers do not have active gas analyzers in the furnace to enable an informed decision on more or less air or fuel.

7.5.5.9.3 Control Overrides

Consider implementing a low oxygen override to the fuel gas pressure controller to keep the boiler within operational limits and prevent a spurious trip (where applicable). This may be accomplished by reducing fuel gas firing at low oxygen conditions to keep the flue gas above the minimum desired oxygen concentration.

When an oxygen analyzer is used for trim control, high-low limiting of the oxygen controller output to either the air or air/fuel ratio controller should be implemented. Should the oxygen analyzer malfunction high, this limitation is applied to maintain the burner within the operating envelope and to prevent the controller from taking the boiler to an unsafe operating condition. To keep the boiler within operational limits, the oxygen trim controller should not be permitted to change the air flow more than the operating margin between $\%O_2$ set point and combustibles breakthrough. For example, where the operating margin between %O_2 set point and combustibles breakthrough has been selected at 2 %, the oxygen trim controller should not change the air flow by more than 10 % (i.e. where 1 %O_2 is estimated at 5 % excess air).

7.5.5.9.4 Alarms

A low oxygen alarm is recommended to alert personnel of a potential low combustion air flow situation.

7.5.5.9.5 Protective Functions

No protective functions are recommended.

7.5.5.10 Low Igniter Gas Pressure

7.5.5.10.1 Process Hazard

Low igniter gas pressure is a process hazard when in use without main burner operation (during start-up or refractory dry-out periods). Igniter gas pressure below that needed for stable flame operation may lead to the accumulation of combustibles (CO or hydrocarbon) within the boiler. See 7.5.5.2 for a description of the hazardous events that may occur.

7.5.5.10.2 Considerations

The following are low igniter gas pressure considerations.

a) When igniters are used, the fuel gas source should be clean and reliable. An independent source of supply is recommended from the main burners to mitigate the common mode failure associated with low fuel gas header pressure upstream of the pressure controls to igniters and burners. Pipeline natural gas or purchased gas is recommended, as refinery gas often contains amines, corrosion products, salts, inert gases, or other particulates that can cause plugging of the igniter burners.

b) Igniters often have a limited operating range of fuel composition. Firing an igniter gas fuel out of the recommended range can cause the igniter to become unstable, to blow out, or to flash back. High hydrogen content or low igniter burner gas pressures may cause flashback and backfiring.

c) Low igniter gas pressure is a significant concern during operation of igniters without main burners. When main burners are on, low igniter pressure alarm notifies that this protection layer may be compromised.

d) In general, Class II and Class III igniters are neither designed nor intended to provide main burner flame stability under all operating conditions.

7.5.5.10.3 Alarms

The igniter gas low-pressure alarm should be set to a pressure above the minimum pressure to maintain a stable igniter flame.

7.5.5.10.4 Protective Functions

For igniters that remain in service with the main burner (e.g. Class I or Class II igniters), an automatic trip of the main igniter gas shutoff valves is recommended if the igniter gas pressure decreases below that required for a stable flame. This is especially important during igniter only operation before introduction of main fuel gas.

7.5.5.11 High Igniter Gas Pressure

7.5.5.11.1 Process Hazard

High igniter gas pressure is a process hazard when in use without main burner operation. Igniter gas pressure above that needed for stable flame operation may lead to the accumulation of combustibles (CO or hydrocarbon) within the boiler. See 7.5.5.2 for a description of the hazardous events that may occur.

7.5.5.11.2 Considerations

The following are high igniter gas pressure considerations.

a) The igniter gas should be from a reliable source and is often independent from the source of gas for the main burners. Pipeline natural gas or purchased gas is recommended, as refinery gas often contains amines, corrosion products, salts or other particulates. Excessive igniter gas pressure will result in igniter flameout.

b) Excessive igniter gas pressure will result in igniter flameout.

c) High igniter gas pressure is a significant concern during igniter light-off and operation of igniters without main burners on. When main burners are operating with Class I or Class II igniters, the high igniter pressure alarm notifies that this protection layer may be compromised.

d) The high-pressure alarm and trips should be set to ensure a stable flame for all possible igniter gas compositions. Operation above the igniter design pressure should be verified by field test.

7.5.5.11.3 Alarms

The igniter gas high-pressure alarm should be set to a pressure below the maximum pressure at which it is possible to maintain a stable igniter flame.

7.5.5.11.4 Protective Functions

For igniters that remain in service with the main burner (e.g. Class I or Class II igniters), an automatic trip of the main igniter gas shutoff valves is recommended if the igniter gas pressure rises above that required for a stable flame. This is especially important during igniter only operation before introduction of main fuel gas.

7.5.6 Equipment Protection

7.5.6.1 High Tube Skin Temperature

7.5.6.1.1 Process Hazard

High tube skin temperatures may result from conditions that include reduction of flow, flow imbalance, scale deposits within the tubes, or operational problems such as poor heat distribution of a poorly operating burners. This condition may result in tube failure or loss of tube life and indicates overfiring, poor heat distribution, flame impingement on the tube, internal scaling of the tube, or low steam flows.

7.5.6.1.2 Considerations

Periodic visual inspection of the proximity of burner flames to firebox tubes is recommended.

The superheater tubes may be protected from high temperature by monitoring the steam header temperature.

7.5.6.1.3 Control Overrides

Not applicable.

7.5.6.1.4 Alarms

Due to the relatively short life span of tube skin thermocouples, alarms are not typically configured.

Where configured, an alarm for high tube skin temperature may aid to prevent damage to tubes due to overheating or to monitor corrosion or fouling trends on certain boilers.

7 5.6.1.5 Protective Functions

No protective functions are recommended.

7.5.6.2 Preheater Malfunction

7.5.6.2.1 General

See also Annex C of this document and API 560, Annex F.

7.5.6.2.2 Process Hazard

For many designs, high and low temperature can lead to mechanical integrity issues (e.g. dew point corrosion, consequent leakage and fouling). For regenerative preheater (rotating wheel) designs, rapid overheating and localized failure can occur.

7.5.6.2.3 Considerations

The following are preheater malfunction considerations.

a) Consider attaching thermocouples to the coldest components of recuperative air preheaters. When sulfur is present in the fuel gas, aqueous sulfuric acid will condense on components that are at or below the dew point of the flue gas. This can lead to corrosion and fouling of the cold end of the exchanger.

b) When thermocouples are attached to the coldest components of recuperative APHs, consider providing a means of bypassing some combustion air around the APH. The cold element temperature can then be controlled by altering the flow through the combustion air bypass.

c) APHs add efficiency to the combustion process. APHs are also essential on boilers using FGR in colder climates. In using FGR to reduce boiler emissions, the amount of moisture in the combustion air is elevated and high moisture FGR is induced into the FD fan and will cause the fan to freeze in cold weather. To minimize the effects of the high moisture FGR, an APH is required. The APH improves the stability of low emissions burners by providing a consistent combustion air input reducing the possible variation in combustion air density.

7.5.6.2.4 Control Overrides

Not applicable.

7.5.6.2.5 Alarms

Where applicable, provide an alarm on the loss of rotation of the regenerative preheater (rotating wheel).

A high flue gas temperature and low flue gas temperature alarm should be provided between the APH and ID fan.

Where applicable, thermocouples attached to the coldest components of recuperative APHs should have a low temperature alarm to warn against the flue gas temperature dropping below the acid dew point. Acid products can cause rapid corrosion to the preheater.

7.5.6.2.6 Protective Functions

For regenerative preheater (rotating wheel) designs an automated corrective action is recommended to avoid mechanical damage. The corrective action depends on the equipment. A bypass is typical along with a trip of the ID fan and opening of the stack damper.

7.6 Pre-ignition Purge Cycle

7.6.1 General

Prior to each start-up, provision shall be made for the removal of combustible gases that may have entered the combustion chamber during the shutdown period. A timed pre-ignition purge cycle shall be repeated after every shutdown of all fuel sources (main fuel gas, waste gas, and igniter fuel gas).

Prior to initiating a purge, precautions should be taken to avoid completing the air-fuel-ignition triangle. By removing any component of the triangle, the likelihood of a deflagration during the purge cycle is significantly reduced.

Should combustibles accumulate in the combustion chamber to an unacceptable hazard level (see 7.5.5.2) prior to a trip, precautions should be taken to mitigate the inrush of air when components within the combustion chamber are hot enough to serve as the source of ignition. See Annex F procedures.

7.6.2 Heated Analyzer Sensors as a Potential Ignition Source

When the purging of a fuel-rich environment may create a hazardous gas mixture in the combustion chamber, provisions should be made to prevent a heated oxygen, combustibles, or methane sensor (without flame arrestors) from becoming an ignition source. Options include the following.

a) Install flame arrestor(s); however, they add lag time (estimated 5 s to 10 s for close-coupled extractive systems and 1 min for in situ probe systems), which is a consideration for process control or process safety applications where response time is critical.

   NOTE For close-coupled extractive systems, the additional lag time associated with flame arrestors (i.e. 5 s to 10 s) is acceptable for most boiler control applications.

b) Without flame arrestor(s), turn off the sensor power when the boiler trips to allow the sensor to cool below the auto-ignition temperature of the fuel gas. Upon restoring power after a brief outage (e.g. during the purge cycle), an oxygen/combustibles sensor may require stabilization time (e.g. 15 min to 30 min) to achieve published accuracy. After an extended outage, a cold combustibles or methane sensor at ambient conditions may have an extended warm-up period (e.g. 4 h to 6 h) for the sensors to stabilize to published accuracy. Refer to the vendor manual for sensor warm-up requirements.

   NOTE 1 Sensors are typically heated to approximately 700 °C (1292 °F). Upon loss of power, it may take a few minutes for the sensor to cool below the auto-ignition temperature of the fuel gas. Consult with the vendor for additional information.

   NOTE 2 Especially during extended outages, the sensor power should not be restored until the purge cycle is complete and the boiler is ready to start. In the event that the block valves have leaked fuel gas into the combustion chamber, this prevents a heated sensor without flame arrestors from becoming an ignition source during the purge cycle.

   NOTE 3 As an advisory, sensor power should be restored prior to introducing fuel gas to reduce the likelihood of sulfur components in the flue gas precipitating/plugging the extractive sample tubes.

c) For close-coupled extractive systems without flame arrestors, reverse flow (blowback) instrument air or nitrogen through the sample probe during the purge cycle. Upon purge complete, standard sample flow is resumed with no sensor stabilization time due to interruption of power.

NOTE Care should be taken with blowback systems to prevent sample contamination with instrument air or nitrogen due to leakage through the automated isolation valve during normal operation. Additionally, the solenoid should be designed fail-safe (i.e. de-energize to trip, fail open), which increases the complexity required to achieve the desired control system response upon analyzer system/power failure. Blowback systems should be periodically tested during routine analyzer calibration.

7.6.3 Purging a Single Burner Water Tube Boiler

For considerations when purging a single burner boiler, see 7.2.3.11.

7.6.4 Purging Multiple Burner Water Tube Boilers (12 Burners or Less)

For considerations when purging a multiple burner boiler, see 7.2.3.12.

7.6.5 Purging the APH

If the combustion chamber is fuel rich, a consideration is to purge the flue gas side of the preheat system by starting the ID fan, closing the stack damper, and purging the firebox in balanced draft mode. However, the ID fan does not typically have sufficient turndown to light the burners in balanced draft mode.

7.6.6 Purging the FGR Ducts

For considerations when purging FGR ducts, refer to 7.2.3.11 for the purging of FGR ducts of single burner water tube boilers or 7.2.3.12 for the purging of FGR ducts of multiple burner water tube boilers.

7.7 Start-up Sequence

7.7.1 General

7.7.1.1 Starting of a cold boiler shall be accomplished in conformance with the manufacturer’s recommendations. In no case shall a boiler that has been taken out of service for maintenance, repair, or extended shutdown be started from a cold condition without a trained operator present.

See Annex F procedures.

7.7.1.2 Fundamental operating rules:

a) conduct a pre-start-up briefing when starting up a boiler;

b) review status of all maintenance performed on the boiler and its related systems to verify that the boiler will support operation;

c) ensure all maintenance related blinds are removed prior to boiler start-up;

d) be cautious of abnormal conditions and smells.

7.7.1.3 Starting up with equipment in good working order is critical to the safe operation of the boiler system. A thorough visual inspection of the boiler system and all associated equipment should be made prior to start-up.

a) Perform visual inspection before start-up.

b) Perform visual inspection of lineup.

c) Check fans and preheater.

d) Communicate with console operator.

e) Perform feedwater start-up.

f) Start feed pumps. Steam turbine driven pumps are often used for their independence from the electric power system, but electric motor driven pumps can also be found in this service.

g) Prepare boiler for feedwater. Verify that the boiler drum is ready to receive the deaerated water. Close all drain valves, bleeds and blowdown valves. Open the feedwater bypass valve around the level controller. Establish a level in the boiler drum while monitoring the level in the deaerator. Once the boiler drum reaches the desired level, close the bypass and line up the level controller.

7.7.1.4 Perform boiler igniter and burner light-off as follows.

a) Verify system lineups and pre-start checks.

b) Prepare gas and air systems for light-off.

c) Verify purge permissives. Once the permissives have been satisfied, the boiler should be purged with fresh air. This is important to ensure no accumulation of fuel or other combustibles in the combustion chamber before initial light-off.

d) Perform purge. Purge requirements vary based on whether the boiler is a single or multi-burner system.

   1) For single boiler systems, the purge is typically at least 8 volume changes and a purge rate of at least 70 % of full load air rate. For additional considerations when purging high velocity or internal FGR burners, see 7.2.3.11.

   2) For multi-burner systems, the purge is typically at least 5 min or 5 volume changes and a purge rate of at least 25 % of full load air rate. For additional considerations when purging multiple burner boilers, see 7.2.3.12.

e) Light-off igniters and main burners. The initial light-off of the first igniter should take place soon after completing the purge. This limits any opportunity for fuel or other combustibles to accumulate in the boiler before light-off.

7.7.1.5 Perform boiler start-up as follows.

a) Begin boiler heat-up. Activities to increase heat input to the boiler must be coordinated with the actions of the console operator. For a multi-burner boiler, this will entail lighting additional burners as needed. It is important to minimize thermal stress on the boiler system and follow local procedures. The steam drum water temperature heat-up rate should not exceed criteria set forth in local procedures, which is typically 56 °C (100 °F) per hour. Exceeding this rate may lead to tube failures or steam explosions.

b) Monitor and maintain steam drum pressure. Observe steam drum water level closely and keep it between predetermined level ranges. Verify level indicators against gauge glasses during start-up. Close the drum vent when pressure reaches 25 psig. When pressure reaches 50 psig, close the superheater drain to the sewer. The superheater vent to atmosphere stays open until the boiler is online. Blow boiler using continuous and/or manual blowdowns to control high level. Add water as needed to maintain level above the low water trip point. Adjust heat-up using tables, and line up feedwater control valve. Limit the boiler heat-up rate to about 56 °C (100 °F) per hour. Exceeding drum pressure warm-up rate may result in equipment damage and/or personnel injury. Steam drum pressure must be slowly increased based on heat-ups designed to protect the tube joints, as well as other boiler components such as the refractory.

c) Supply steam to header. Once the steam has reached the appropriate conditions, it may be exported to the steam header system. The desuperheater vent should be closed at this time, along with all remaining bleeds and drains. The boiler should still be closely monitored for correct feed flow, air/fuel ratio, fuel pressure, and fans and preheaters.

d) Line up continuous blowdown and feedwater controller, if not already done so.

7.7.1.6 Perform boiler post-start-up checks as follows.

a) Perform visual surveillance of flame and combustion chamber. Check for hazy combustion chamber and flame impingement onto tubes. Observe flames for signs of incorrect air/fuel ratio.

b) Adjust excess air. Checks that the oxygen analyzer reading is within prescribed values and the flue gas combustible reading is below the maximum value.

c) Obtain water samples from steam drum and blowdown.

7.7.2 Typical Gas Fired Single Burner Start-up Sequence Narrative

Normal boiler start-up should be fully automated to the extent feasible in order to minimize exposure to personnel in the field. If site practices require, a hold may be placed at the end of igniter light-off until a second “start main flame” pushbutton is activated. In this case, a time-out forcing the sequence to trip and return to the beginning must be implemented in order to prevent damage to the igniter and burner assembly, or possible environmental exceedances.

NOTE Class 3 igniters are not typically designed for continuous operation and may burn out, or damage the burner assembly, or increase emissions, so care must be taken with any potential sequence hold placed between igniter and main light-off. If Class 3 igniters are intended to be operated for extended time periods, the purchaser should indicate this requirement to the igniter manufacturer. The boiler manufacturer should be consulted and any recommendations provided by the manufacturer should be followed.

Start-up should not be permitted with any of the BMS instrumentation in bypass or inputs forced. Excluding flame scanners, start-up with redundant instrumentation in a fault condition is allowed if the voting logic is degraded to at least 1ooM (i.e. for NooM voting).

The recommended start-up sequence is as follows.

a) Satisfy all permissives.

   1) Permissive logic should include a check that all flame scanners are not registering flame, main fuel safety shutdown valves are in the closed position, and air fan has started, in order to proceed.

   2) Permissive logic should confirm that all trips are in the appropriate safe (non-activated) state. The exception will be low fuel gas pressure, which will require a start-up override.

b) Initiate start sequence.

c) Complete boiler purge cycle.

   1) Purge airflow should be proven to be above 70 % of the MCR air flow.

   2) Purge conditions should meet either air pressure and open damper position interlocks, or airflow interlocks.

3) Purge cycle time should be sufficient to achieve a minimum of eight volume air changes. For additional considerations when purging high velocity or internal FGR burners, see 7.2.3.11.

d) Upon purge complete, verify all dampers are at light-off (min fire) positions.

e) Open the igniter fuel safety shutdown valves and energize the ignition transformer for 10 s.

f) Igniter flame should be proven by the igniter scanner that has been established as capable of seeing the igniter flame.

g) If igniter flame is not proven within the 10 s TFI period, the individual igniter SSVs shall be closed and the cause of failure to ignite shall be determined and corrected. With airflow maintained at light-off conditions, a re-purge shall not be required, but at least 1 min shall elapse before a retrial of this or any other igniter is attempted. Repeated retrials of igniters without investigating and correcting the cause of the malfunction shall be prohibited. As a general rule, retrials should be limited to a maximum of three light-off attempts prior to initiating a re-purge.

h) If igniter flame is proven at the end of the TFI period, commence a stabilization period (e.g. 5 s to 15 s) to confirm that the igniter flame remains established via the igniter flame scanner. For additional clarification on timing sequences and stabilization time, see 7.2.3.15.

i) If igniter flame is confirmed as established, continue to the next step.

j) Permissive logic should include fuel gas supply pressure upstream of the SSVs to ensure that pressure is between the high and low limit. Where the blocked in fuel gas has increased to supply header pressure, it may be vented to flare or a safe location prior to proceeding with light-off of main burner(s).

k) If site practices require, a hold may be placed at this point until a second “start main flame” pushbutton is activated. If the igniter is not designed for continuous operation independent of the main burner, a time-out forcing the sequence to trip and return to the beginning must be implemented in order to prevent damage to the igniter and burner assembly, or possible environmental exceedances. Consult the vendor for time limits of Class 3 igniters in continuous service.

   1) Confirm that air dampers and the MFGCV are in their respective light-off position. Permissives should include MFGCV and air dampers are at the minimum fire positions confirmed by position transmitters or limit switches.

   2) Prove that the MFGCV remains at minimum fire light-off position and does not move during light-off at any time before being released to modulate after main flame is proven. Alternate consideration for BMS supervision of light-off conditions is noted in 7.2.3.10.

l) Open main fuel safety shutdown valves.

m) Close the igniter safety shutdown valves.

n) Main flame should be proven by flame scanners that have been established to see the main flame.

o) Commence a second stabilization (e.g. 5 s to 15 s) period to confirm that the main flame remains stable. For additional clarification on timing sequences and stabilization time, see 7.2.3.15.

p) If main flame presence remains proven for the stabilization period, release to modulating control in the BPCS once the board operator initiates the transfer from the BPCS console.

q) The release to modulation should be coordinated with the BPCS configuration so that a bumpless transfer of MFGCV occurs.

7.8 Manual Trip (Shutdown)

A manual trip shall be provided to trip the shutdown devices through the protective system. No further action is recommended until the incident is evaluated by the operator and further action can be taken. Automatically adding more air to the boiler is not recommended as this could increase the hazard.

a) Most manual trips are hardwired to interrupt power to the field devices. Some safety certified programmable logic solvers have special certification allowing manual trip pushbuttons to be wired directly to the logic solver input, and the logic solver interrupts power to the field devices. Consult the vendor safety manual.

b) When integrated into a programmable logic solver, the protective system logic shall not have logic designed to prevent the manual shutdown from occurring, e.g. regardless of logic state, alarm states, process measurements, etc.

c) The manual trip, hardwired to the logic system, shall use latching logic. A pull to trip switch is a design consideration to minimize nuisance initiation. A pull or push to trip policy should be uniformly applied across the facility, and the required action should be clearly labeled and visible to the operator.

d) The manual trips shall be clearly designated and identified.

e) A local manual trip is recommended. The local manual trip must be located within visible distance from the boiler to allow safe access and egress during an emergency situation; for example, if a flameout or other hazardous event occurs. Typical locations are on field panels.

f) Where existing field panels do not allow for safe access and egress during an emergency situation, or where the radiant heat from a boiler fire may prohibit access, it is recommended to have a secondary manual trip outside of a 15.25 m (50 ft) zone. A design consideration is to install a manual quarter turn tight shutoff valve outside battery limits [>15.25 m (>50 ft)] clearly marked for emergency isolation.

g) A minimum of two ESD locations is recommended. Therefore, if a manual trip location outside of a 15.25 m (50 ft) zone is not available, then a remote manual trip from a continuously manned location (always recommended), such as a central control room, may be required (e.g. BPCS remote trip).

7.9 Safety Shutoff Valves

7.9.1 Design Specifications

SSVs are used to automatically isolate fuel sources (e.g. fuel gas/oil, igniter gas, or waste heat gas) at the boiler after initiation by any of the protective functions, including manual shutdown.

SSVs shall not have hand wheels.

SSVs should not be used in lieu of manual isolation valve(s) and/or spectacle blind(s) for extended shutdown periods.

SSVs shall be fail-safe (i.e. spring return fail closed) upon loss of holding medium (e.g. air or electric) and shall remain closed until manually reset (e.g. local or remote) following any interlock shutdown.

For electro-pneumatic SSVs:

a) solenoid valves shall be de-energized to trip;

b) where used, manual reset solenoids shall not allow forcing or reset to the energized position (i.e. normal operating position) when de-energized. For a local manual reset, the solenoid will typically have either an integral reset pushbutton or a lever arm (e.g. free handle) that cannot be defeated.

- SSVs shall be fire safe per API 607 or API 6FA.

- SSVs should provide tight shutoff (e.g. bubble tight) per API 598. Tight shutoff is not a performance criterion to achieve safe state. Instead, tight shutoff is specified to ensure that fuel gas does not accumulate in the boiler during an extended shutdown. The criteria for resolving unacceptable seat leakage rates (e.g. with valve proving systems) and valve maintenance intervals should be determined by the owner/operator.

SSVs shall be provided with proof-of-closure indication for shutdown verification and start-up sequencing.

a) A failure-to-close diagnostic alarm is recommended if a SSV fails to close within the prescribed time requirements (e.g. generate a diagnostic alarm within 5 s to 10 s or twice the valve stroke time).

NOTE If proof of closure at the SSV(s) to the burner where flame has been lost is not confirmed closed within time constraints, additional corrective action should be taken. If predetermined to be safe, a failure-to-close diagnostic alarm should notify the operator to manually isolate the burner. This scenario is more likely for boilers with a single automated block at each burner.

b) If both SSVs fail to close, the operator should assume loss of flame, clear the area of personnel, and isolate fuel gas outside battery limits prior to approaching the boiler.

NOTE For clarification, Item b) typically applies to single burner boilers. It may also apply to multiple burner boilers with two SSVs in the main fuel gas header and no SSVs at the individual burners.

The shutoff valve actuators should be sized with a safety factor well above the minimum torque requirements. For clarification:

a) when selecting the spring range for an SSV actuator, a valve manufacturer will typically apply a standard safety factor (e.g. 15 % to 20 %) to the valve torque requirements. Design considerations typically include the minimum available air pressure, the maximum differential pressure across the valve, and process conditions that could cause the valve to stick. For safety critical applications, SSVs should be designed with an additional safety factor (e.g. 25 % to 40 %) to valve torque requirements to account for unknown variability in these parameters;

b) as a design target, apply a safety factor of 1.4 to 1.6 times the minimum valve torque requirements and size the actuator using the design minimum air supply pressure specified by the site (e.g. 60 psig).

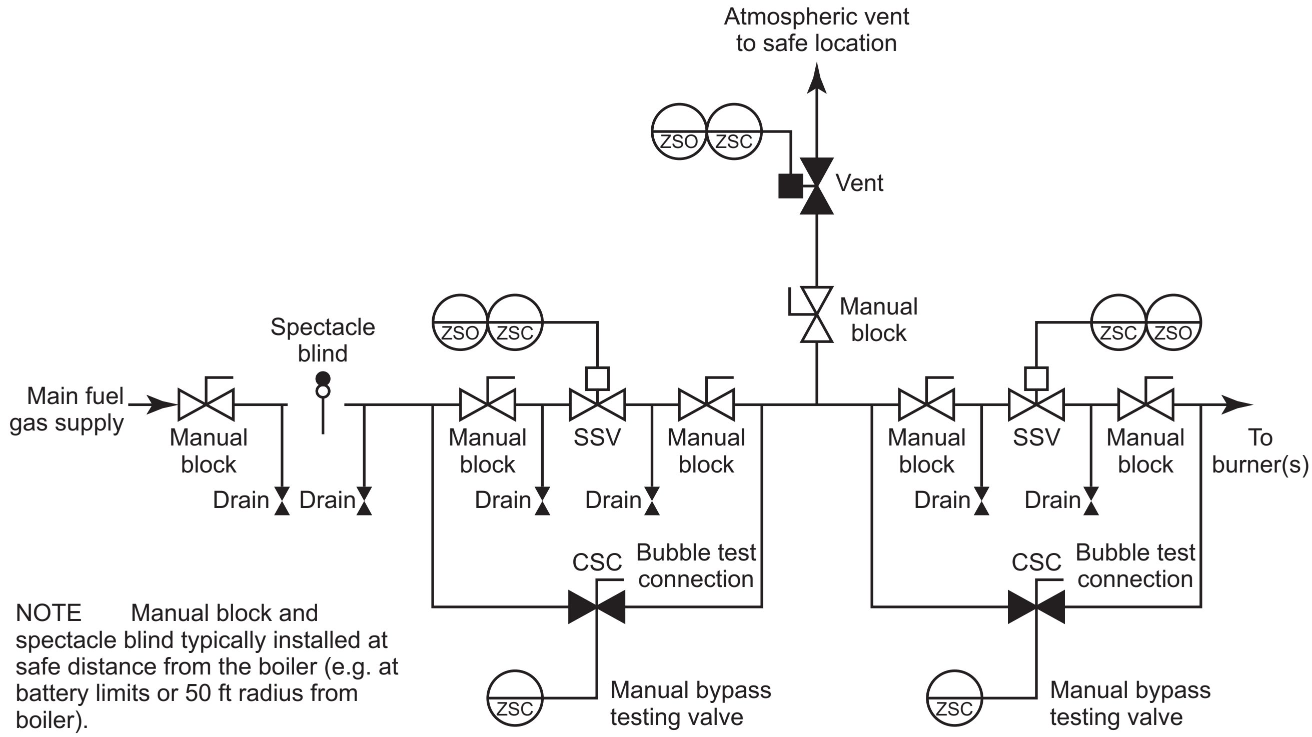
As an advisory for SSVs in refinery fuel gas service, quarter turn or quick turn valves (e.g. ball valves) are recommended. While knife gate valves are commonly used in natural gas service, they are prone to sticking in dirty refinery fuel gas service.

7.9.2 Provisions for Online Testing of Main SSVs

Within the refining and petrochemical industry, the AHJ in some states (e.g. Texas) allows an extension of the internal boiler inspection interval for up to 5 years between shutdowns. In these jurisdictions, provisions for testing of the SSVs between inspection shutdowns are an important consideration to achieve safety availability requirements. For additional clarification, see 7.2.3.7.

To facilitate full stroke online testing and maintenance of the main SSVs (i.e. not those at individual burners), a manual bypass block valve may be installed in parallel with each SSV. The design objective is to ensure that at least one SSV is always in service to respond to a MFT. Consider the following options:

— Option 1—An independent bypass testing arrangement may be installed in parallel with each of the two SSVs. This arrangement permits individual testing of the SSVs, and provided proper procedures are followed at least one of the two SSVs is always in service to interrupt the fuel supply in the event of a MFT. Figure 26 depicts a bypass testing arrangement using Option 1.



Option 1

- Shown with independent bypass valve testing arrangements and a minimum number of manual blocks and drains to facilitate online testing.
- Bypass valves must be car sealed closed (preferably with a locking device) and have limit switches that alarm at a continuously monitored location when open.
- Control of Defeat Procedures require signed authorization to open a single bypass valve and limit the unavailability of each SSV during online testing to less than 5 minutes.
- Control of Defeat Procedures prohibit both bypass valves from being opened simultaneously.
- Limit switches on bypass valves and SSVs must be proven closed in the BMS as a startup permissive.

Figure 26—Example Bypass Testing Arrangement, Option 1

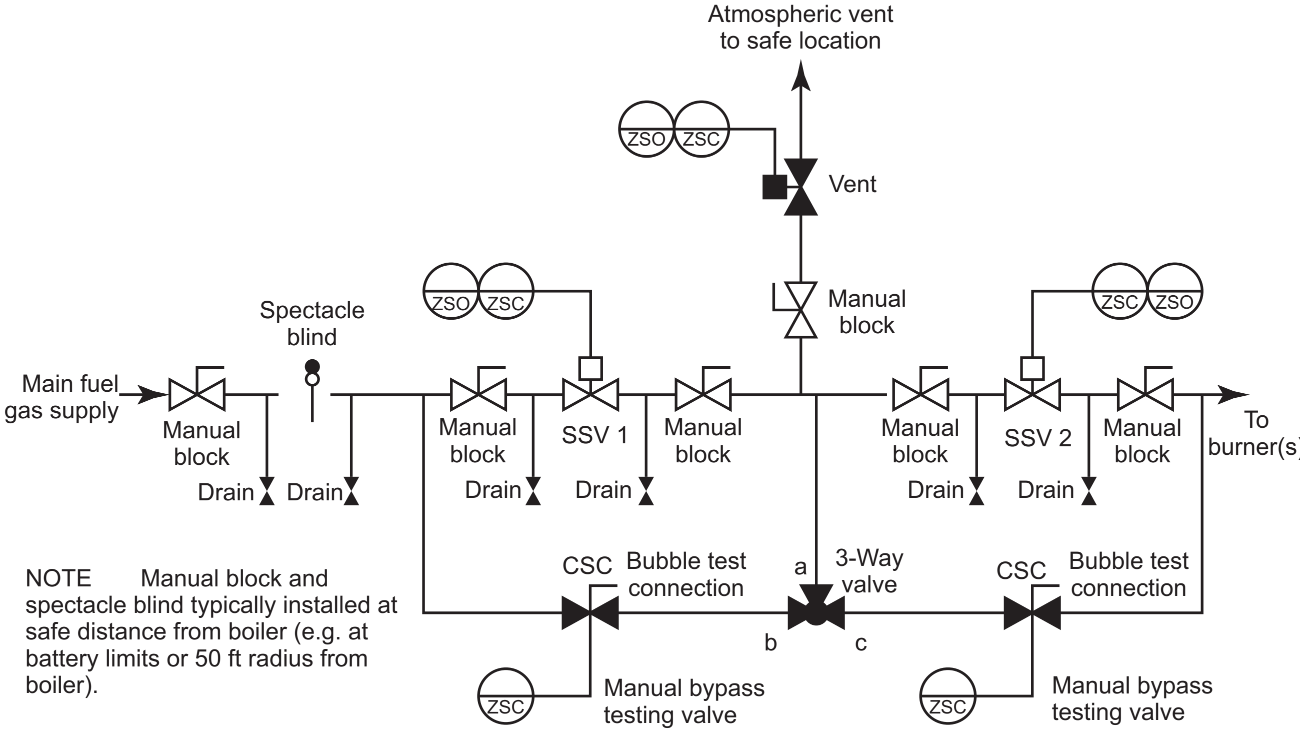
— Option 2—A bypass testing arrangement is shown in Figure 27 using Option 2. This arrangement uses a manual block around each SSV in conjunction with a three-way valve located in the bypass piping. This arrangement ensures an open path around one of the two SSVs and prevents intentional or inadvertent bypassing of both SSVs simultaneously. This arrangement permits individual testing of the SSVs and ensures that at least one of the two SSVs is always in service to interrupt the fuel supply in the event of a MFT.

Where required or designed for testing the following apply.

a) The specifications for the bypass testing valves should meet or exceed those of the SSVs:

   1) safety shutoff bypass valves shall either be fire safe per API 607 or API 6FA;

   2) as a design consideration to minimize seat leakage through the bypass valves, a trunnion ball valve may be substituted for a floating ball valve. A floating ball valve requires upstream line pressure to push the ball into the



Option 2

- Shown with independent bypass valve testing arrangements and a minimum number of manual blocks and drains to facilitate online testing.
- Bypass valves must be car sealed closed (preferably with a locking device) and have limit switches that alarm at a continuously monitored location when open.
- Control of Defeat Procedures require signed authorization to open a single bypass valve and limit the unavailability of each SSV during online testing to less than 5 minutes.
- Shown with a 3-way valve to prevent both SSVs from being taken out of service simultaneously.
    - 3-way valve aligned to position a->b allows SSV1 to be tested online with SSV2 in service.
    - 3-way valve aligned to position a->c allows SSV2 to be tested online with SSV1 in service.
    - During normal operation, both bypass valves are closed and the position of the 3-way valve is not critical.
- Limit switches on bypass valves and SSVs must be proven closed in the BMS as a startup permissive.

Figure 27—Example Bypass Testing Arrangement, Option 2

downstream seat. In contrast, a trunnion ball valve has floating seats to provide tight shutoff in both directions and does not require line pressure to seat the valve.

b) Bypass valves shall not be used to bypass unsafe process conditions.

c) The bypass valve shall not be used as a start-up bypass valve.

d) Bypass valves shall have proof-of-closure limit switches as a purge permissive interlock to the BMS.

e) Bypass valves shall be provided with a proof-of-closure status alarm in a continuously monitored location (i.e. alarm when not closed) and car sealed closed (or locked) when not in use.

f) A formal policy, permitting procedure, and signed authorization shall be required prior to opening the bypass valve.

g) Quarter turn or quick turn manual valves (e.g. ball valves) that can be quickly closed in an emergency are recommended.

7.10 Trips and Alarms

• Table 15 lists the typical alarms and trips for boilers. The owner shall expand on these trips and alarms during hazard and operability reviews of the steam, BFW, combustion, and flame monitoring systems. These alarms and shutdowns are based on the requirements of NFPA 85.

Table 15—Typical Alarms and Shutdown

Description	Alarm/Pre-alarm	Shutdown (Note 1)	Comment
Low fuel gas supply pressure	X		Permissive
High fuel gas supply pressure	X		Permissive
Loss of combustion air flow	X	X	7.5.5.3
Loss of operating forced draft fan	X	X	7.5.5.3
Low furnace pressure	X		7.5.5.4
High furnace pressure	X	X	7.5.5.5
Loss of operating induced draft fan	X	X	7.5.5.5
Low fuel gas burner pressure	X	X	7.5.5.6
High fuel gas burner pressure	X	X	7.5.5.7
Low igniter fuel gas pressure	X	X (Note 2)	7.5.5.10
High igniter fuel gas pressure	X	X (Note 2)	7.5.5.11
Partial loss of flame introducing hazard	X	X (Note 3)	7.5.5.2.5
Total loss of flame		X	7.5.5.2.5
Burner safety shutoff valve fails to close	X		7.9.1
Loss of interlock power			7.2.3.13
Loss of control power			7.2.3.13
Low control/instrument air pressure	X		7.2.3.13
Low oil supply header pressure		X	
Low fuel oil burner header pressure	X		
Low fuel oil temperature	X		
Low atomizer media pressure	X	X (Note 4)	
Low igniter atomizer media pressure	X	X (Note 4)	
Low feedwater temperature/pressure	X		
High super heater temperature	X		
High-high super heater outlet temperature		X (Note 5)	
Low drum water level	X		
Low-low drum water level	X	X (Note 6)	7.2.3.4
High drum water level	X		
High-high drum water level		X (Note 5)	
Low oxygen/high CO or combustibles in flue gas	X		7.5.5.9
High NOx levels in flue gas	X		
Manual trip	X	X	7.8, 7.2.3.2

Table 15 Notes
NOTE 1 It is recommended that shutdowns be implemented with alarm/logging systems capable of capturing first out and sequence of events alarms. An annunciator system showing the first out sequence should be integrated into the BPCS.
NOTE 2 Not required for Class 3 intermittent igniters, which are limited to operation during the light-off sequence. For continuous igniters, this is an igniter trip when main burners are in service and a boiler shutdown when only the igniter(s) are in service.
NOTE 3 In most cases, upon partial loss of flame the BMS will isolate the SSV(s) at an individual burner(s). On legacy multiple burner boilers without automated SSV(s) at each burner, a master fuel trip of the boiler may be required to mitigate the hazard.
NOTE 4 When firing a liquid fuel, insufficient atomizing media (steam or air) pressure may cause an unstable flame and ultimately lead to high combust ble levels inside the boiler firebox. If the atomizing media's pressure is too low and/or not sufficiently above that of the fuel, the fuel flow to that burner or igniter must be shut off. An alarm or pre-alarm of this condition is warranted.
NOTE 5 Optional. The user should evaluate the impact to downstream piping and equipment via hazard analysis to determine whether or not a trip is required. This may be a recommended vendor trip for equipment protection.
NOTE 6 A low water level inside the steam dream should be alarmed and initiate operator action to correct the problem if the trend continues. A low-low water level, set just above the lowest safe operating level in the boiler, should initiate a master fuel trip.

8 Centrifugal Fans and Drivers

8.1 General

API 538 addresses requirements for centrifugal fans and drivers particular to industrial fired boilers that operate in refinery and petrochemical plant environments. Other industry standards describe requirements for centrifugal fans and drivers. Rather than duplicate their requirements and considerations, API 538 lists standards used to specify boiler fan requirements for industrial fired boilers.

API 538 is not standalone. It should be used with the referenced documents described below. Selected excerpts from these standards are included in this section for illustrative purposes only.

a) API Standard 560, *Fired Heaters for General Refinery Service*—This standard addresses fans' and drivers' requirements as they relate to fired heaters. Fan requirements for small boilers are similar to these fired heater fan requirements. The fan purchaser has the responsibility to provide complete required operating data (such as flow rate, pressure, pressure rise, temperature, and inlet gas density) to the fan manufacturer.

• 1) This standard's Annex A includes fan data sheets suitable for specifying fan requirements by the purchaser and provides proposals examples for the vendor.

2) This standard's Annex E specifies requirements and gives recommendations for centrifugal fans intended for continuous duty. These requirements include fan design, accessories, examination and testing, preparation for shipment, and vendor's data.

b) API Standard 673, C*entrifugal Fans for Petroleum, Chemical, and Gas Industry Services*—This standard covers the minimum requirements for centrifugal fans intended for continuous duty in petroleum, chemical, and gas industry services. Some requirements may be more suitable for larger boilers rather than typical industrial fired boilers that are smaller in steam capacity. Fan pressure rise is limited to differential from a single impeller, usually not exceeding 2500 mm (100 in.) of water equivalent air pressure (EAP). Positive displacement blowers are NOT covered by this standard.

c) API Standard 611, *General-purpose Steam Turbines for Petroleum, Chemical, and Gas Industry Service*—This standard specifies the minimum requirements for general-purpose steam turbines. These requirements include basic design, materials, related lubrication systems, controls, auxiliary equipment, and accessories. General-purpose turbines are horizontal or vertical turbines used to drive equipment that is usually spared, is relatively small in size (power), or is in non-critical service. This equipment is generally used where steam conditions will not exceed a pressure of 4800 kPa [700 psi (ga)] and a temperature of 400 °C (750 °F) or where speed will not exceed 6000 r/min.

d) API Standard 612/ISO 10437, *Petroleum, Petrochemical, and Natural Gas Industries—Steam Turbines—Special-purpose Applications*—This international standard specifies requirements and gives recommendations for the design, materials, fabrication, inspection, testing, and preparation for shipment of steam turbines for special-purpose applications. Special-purpose turbines are those horizontal turbines used to drive equipment that is usually not spared, is relatively large in size (power), or is in critical service. This category is not limited by steam conditions or turbine speed.

1) This standard also covers the related lube-oil systems, instrumentation, control systems, and auxiliary equipment. It is not applicable to general-purpose steam turbines, which are covered in ISO 10436.

• 2) The purchaser shall specify the equipment's normal operating point and any other required operating points, including the inlet and exhaust steam conditions and any extraction or induction steam quantities and pressures. The purchaser shall also specify the maximum and minimum values of inlet, exhaust, and extraction/induction steam conditions.

e) API Standard 613, *Special Purpose Gear Units for Petroleum, Chemical and Gas Industry Services*—Covers the minimum requirements for special-purpose, enclosed, precision, single- and double-helical one- and two-stage speed increasers and reducers of parallel-shaft design for petroleum, chemical, and gas industry services. This standard is primarily intended for gears that are in continuous service without installed spare equipment. This standard includes related lubricating systems, controls, instrumentation, and other auxiliary equipment. This standard does not apply to gear units in general-purpose service, which are covered by API 677; to gears integral with other equipment, such as integrally geared compressors, which are covered by API 617 or API 672; or to gears other than helical.

• f) API Standard 614/ISO 10438-1, *Lubrication, Shaft-sealing, and Oil-control Systems and Auxiliaries*—Covers the minimum requirements for general-purpose and special-purpose oil systems. This standard also includes requirements for self-acting gas seal support systems. The standard includes the system components, along with the required controls and instrumentation. Data sheets and typical schematics of both system components and complete systems are also provided. The purchaser shall specify whether the general-purpose or special-purpose specification will be applied. General-purpose systems are usually spared or in non-critical service. Special-purpose applications have equipment designed for uninterrupted, continuous operation in critical service, and for which there is usually no spare equipment.

g) API Standard 541, *Form-wound Squirrel-cage Induction Motors—375 kW (500 Horsepower and Larger)*—Covers the minimum requirements for all form-wound squirrel-cage induction motors 500 horsepower and larger for use in petroleum industry services. This standard may be applied to adjustable speed motors and induction generators with appropriate attention to the specific requirements of such applications.

h) API Standard 547, *General-Purpose Form-Wound Squirrel Cage Induction Motors-250 Horsepower and Larger*—Covers the requirements for form-wound induction motors for use in general purpose petroleum, chemical and other industrial severe duty applications. API 547 motors:

1) are rated 250 hp (185 kW) through 3000 hp (2250 kW) for 4, 6, and 8 pole speeds;

2) are rated less than 800 hp (600 kW) for two-pole (3000 RPM or 3600 RPM) motors of totally-enclosed construction;

3) are rated less than 1250 hp (930 kW) for two-pole motors of WP-II type enclosures;

4) drive centrifugal loads;

5) drive loads having inertia values within those listed in NEMA MG 1 Part 20); and

6) are not induction generators.

The title is indicative of content.

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

j) AMCA Publication 99, *Standards Handbook*—A compilation of AMCA standards that include fan laws, common industry terminology and symbols, classifications for spark-resistant construction, etc.

k) ANSI/AMCA Standard 301, *Methods for Calculating Fan Sound Ratings from Laboratory Test Data*—Title is indicative of content.

l) ANSI/AMCA Standard 210, ANSI/ASHRAE 51, *Laboratory Methods of Testing Fans for Certified Aerodynamic Performance Rating*—Defines uniform methods for conducting laboratory tests on housed fans to determine airflow rate, pressure, power, and efficiency, at a given rotational speed.

m) AMCA Publication 201, *Fans and Systems*—This fan application manual has been updated with separate axial fan factors. It discusses the effect of inlet and outlet connections on fan performance.

n) AMCA Publication 801—*Industrial Process/Power Generation Fans: Specification Guidelines*—Provides information on testing and rating power plant fans and covers construction features and related accessories. Sample equipment specifications are included that outline the information a fan manufacturer requires to select the best fan for an application. Common fan industry practices are also defined and explained.

8.2 Mechanical

Selected excerpts from these standards are included in this section for illustration purposes only.

The centrifugal fan and driver equipment (including auxiliaries) shall be designed and constructed for a minimum service life of 20 years and at least three years of uninterrupted operation. It is recognized that this is a design criterion. Fans shall not exceed the rating limits of the manufacturer's design.

Data sheets for FD and ID fans are included in Annex A, Data Sheet 8.

The fan shall be mechanically designed, as a minimum, for continuous operation at the following temperatures:

a) 56 °C (100 °F) above the maximum expected inlet temperature to induced-draft fans, considering fouling of finned surfaces;

b) 14 °C (25 °F) above the maximum specified ambient air temperature to forced-draft fans.

Fan components and accessories shall be designed to withstand all loads and stresses during rapid load changes such as starting, failure of damper operator, or sudden position change of dampers.

Considerations for driver sizing and starting operations are covered in API 560, Annex E, which specifies requirements and gives recommendations for centrifugal fans intended for continuous duty. Margins for flow and pressure rise are required to determine fan test block conditions or fan rating point.

Fan inlets shall be designed as described below.

• a) For forced-draft fans, provision of the inlet equipment and arrangements, including silencer(s) and transition piece(s), shall be coordinated between the fan purchaser and the fan vendor. (Portions may normally be supplied by each.)

• b) Unless otherwise specified, the air intake shall be at least 4.5 m (15 ft) above grade. The purchaser shall evaluate air-intake elevation requirements, considering the possibility of dust entering the system and causing surface fouling, the area noise-limitation requirement and the corresponding need for a silencer, the possibility of combustible vapor entering the fan, and power penalties for inlet stack and silencer configurations. The normal operating flow of fans is defined as the air required supporting combustion for the boiler's burners at MCR with the specified excess air, fuel analyses, and ambient conditions.

c) The fan inlet equipment shall include intake cap or hood, trash screen, ducting and support, inlet damper or guide vanes, inlet boxes, and silencer, as required. All components shipped separately shall be flanged for assembly. The inlet equipment assembly shall be designed for the wind load shown on the fan data sheet.

- The arrangement of the equipment, including ducting and auxiliaries, shall be developed jointly by the purchaser and the boiler vendor. The arrangement shall provide adequate clearance areas and safe access for operation, maintenance, and removal.

All equipment shall be designed to permit rapid and economical maintenance. Major parts, such as fan housing, inlet cone, and bearing housings, shall be designed (shouldered or dowelled) and manufactured to ensure accurate alignment on reassembly. Field dowelling by others may be required after final alignment.

The fan vendor shall formally review and approve or comment on the fan purchaser's inlet and outlet duct and equipment arrangement drawings. This review shall consider structural aspects such as loading on fan parts, and configuration details that impact fan performance as described in AMCA 801.

- Foundation drawing review by the fan vendor is not required, unless specified by the purchaser.

- Fans, drivers, and auxiliary equipment shall be suitable for installation outdoors with no roof, unless otherwise specified. The purchaser shall specify the weather and environmental conditions in which the equipment shall operate (including maximum and minimum temperatures and any unusual humidity or dust conditions). For the purchaser's guidance, the vendor shall list in the proposal any special protection that the purchaser is required to supply before and after installation.

8.3 Steam Turbine and Electric Motor Drives

API standards describing mechanical specifics are listed in Section 8.

Selected excerpts from API 560, API 673, and AMCA Publication 201 are included in this section for illustrative purposes only.

- a) Motors, electrical components, and electrical installations shall be suitable for the area classification (class, group, and division) specified by the purchaser, as well as local codes specified and furnished by the purchaser.

- b) The selected operating speed of the fan shall not exceed 1800 rpm, unless otherwise approved by the purchaser.

c) Fan arrangement and bearing support shall be in accordance with AMCA 801:2001, Arrangement 3 or Arrangement 7, with the fan impeller located between bearings, the bearings mounted independently of the fan housing on rigid pedestals and sole plates, and the bearings protected from the air or gas stream if any of the following conditions exist:

1) driver rated power of 112 kW (150 BHP) or greater,

2) speed greater than 1800 rpm,

3) maximum specified operating temperature greater than 235 °C (455 °F),

4) corrosive or erosive service,

5) service subject to fouling deposits that could cause rotor unbalance.

• d) For services not subject to the above conditions, AMCA 801:2001, Arrangements 1, 8, and 9, all with bearings mounted independent of the fan housing, may be used if approved by the purchaser.

e) For fan selection, it should also be considered that reduced speed is desirable for erosive service and for units subject to fouling deposits on the rotor; belt drives should be limited to no more than 75 kW (100 BHP) rated driver size.

f) If drivers are rated less than 30 kW (40 BHP) and speeds greater than 1800 r/min, AMCA 801:2001 Arrangements other than 3 and 7 may be specified on the data sheet.

• g) The type of driver shall be specified by the purchaser. The driver shall be sized to meet the fan rated point conditions, including external gear and/or coupling losses and off-power drag of the start-up motor (if any), and shall be in accordance with applicable specifications, as stated in the enquiry and order. The driver shall be sized and designed for satisfactory operation under the utility and site conditions specified by the purchaser.

• h) Anticipated process variations that can affect the sizing of the driver (such as changes in the pressure, temperature or properties of the fluid handled, as well as special plant start-up conditions) shall be specified by the purchaser.

i) Forced-draft fan-driver sizing shall consider fan performance at minimum ambient temperature.

j) Induced-draft fan-driver sizing shall consider possible variations in operating temperature and gas density (e.g. a cold start).

k) Provisions for flow control, through damper control or speed variation, allow for start-up and operation to be at a lower-than-normal process operating temperature. With these features, the need for greater driver size to handle low temperatures can be avoided. Operating instructions shall cover the use of dampers or speed control for such cases, particularly at start-up.

• l) The starting conditions for the driven equipment shall be specified by the purchaser, and the starting method shall be mutually agreed upon by the purchaser and the fan vendor. The driver's starting torque capabilities shall exceed the speed-torque requirements of the driven equipment. The fan vendor shall verify that the starting characteristics of the fan and driver are compatible.

m) Unless otherwise specified, motor-driven fans shall be direct connected.

n) For motor-driven units, the motor nameplate rating (exclusive of the service factor) shall be at least 110 % of the greatest power required (including gear and coupling losses) for all of the specified operating conditions.

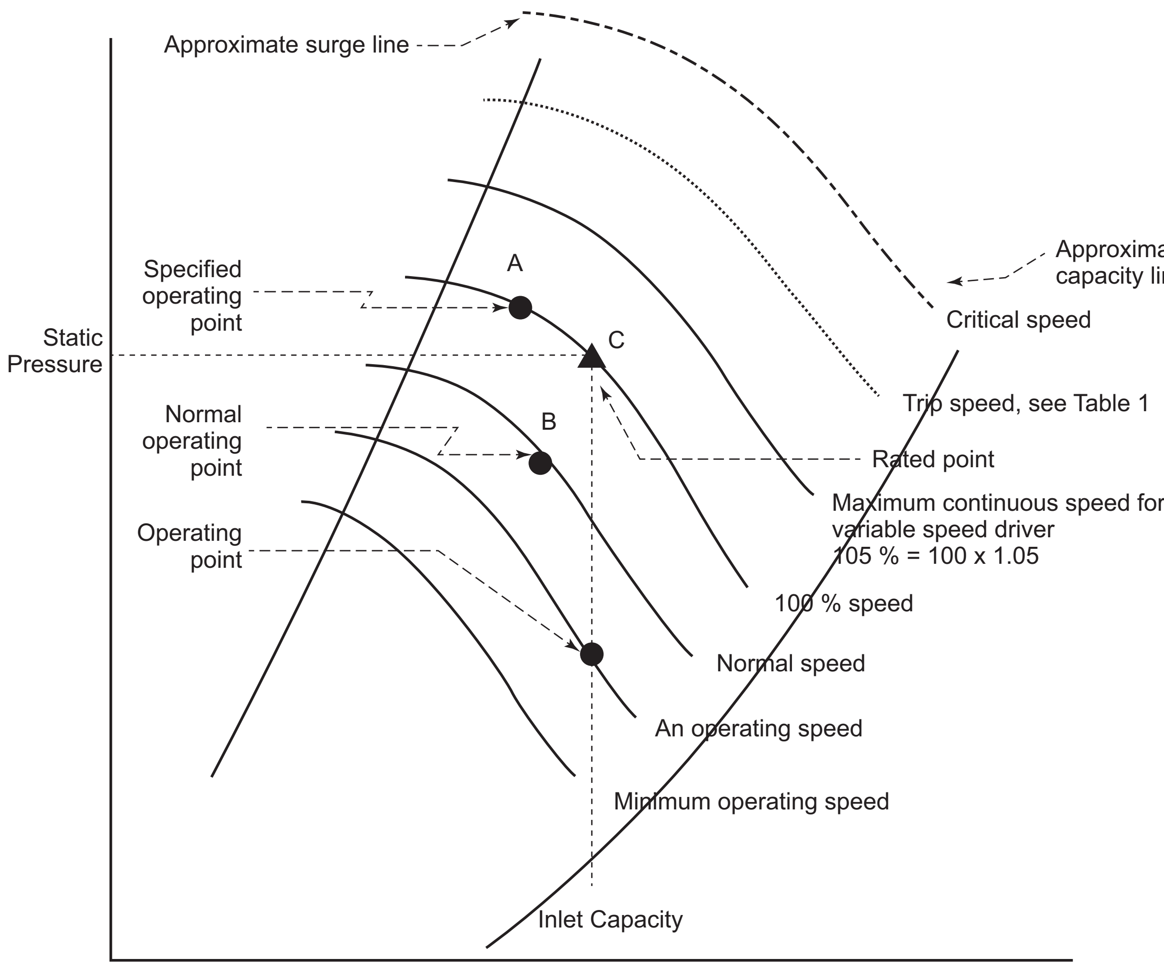
o) Full load and starting current, system centrifugal force, and curves showing motor speed-torque, speed-current, and speed-power factors shall be provided for each fan drive.

p) Motor drivers shall be capable of starting the fan, with the control damper in the minimum position, with 80 % of the design voltage applied.

8.4 System Resistance Curves

API 560 and API 673 contain the following descriptions regarding system resistance curves. Selected excerpts from these standards are included in this section for illustrative purposes only.

• Fans shall be designed to operate satisfactorily at all specified operating conditions. The two operating points of particular concern are the rated point and the normal operating point. See Figure 28 for a typical fan system resistance curve. It shall be the responsibility of the fan purchaser to provide complete required operating data (such as flow rate, pressure, pressure rise, temperature, and inlet gas density) to the fan manufacturer. In developing these data, the fan purchaser shall consider the following.



NOTE 1 Except where specific numerical relationships are stated, the relative values implied in this figure are assumed values for illustration only.

NOTE 2 The 100 % speed curve is determined from the operating point requiring the highest static pressure; point A in the illustration.

NOTE 3 Fan rated point is (1) the highest speed necessary to meet any specified operating condition and (2) the rated capacity required by fan designs to meet all specified operating points.

NOTE 4 Refer to API 673, Section 2.7, for discussion of critical speeds.

NOTE 5 For trip speeds, see API 673. Trip speed (revolutions per minute) is the speed at which the independent emergency overspeed device operates to shut down a prime mover.

Figure 28—Fan System Resistance Curve

a) The normal operating point is that point at which it is expected that the boiler will be operated most of the time. It shall be the fan manufacturer's responsibility to optimize the fan's efficiency as close to this point as practical. This operating point shall be consistent with the normal heat release of the burners for the design total absorbed boiler duty and efficiency.

• b) The fan rated point shall include the flow required (including all surpluses for excess air, system leakage, and design safety factor) to meet the design heat release. In no case shall the rated point be less than 110 % of the normal operating flow. The normal operating flow of fans is defined as the air required for supporting combustion for the boiler's burners at MCR with the specified excess air, fuel analyses and ambient conditions. The fan purchaser shall specify the fan static pressure rise and temperature required for the rated point. In no case shall the rated point be achieved with the fan inlet damper beyond 100 % of the full open position.

c) The fan rated point shall be selected to best encompass specified operating conditions within the scope of the expected performance curve.

d) Unless otherwise specified, fans shall have turndown capability of 60 % or less of rated flow. For parallel operations, fan performance shall have a continuously rising pressure characteristic (pressure versus flow plot) from the rated capacity to surge. Performance curves, corrected for the specified gas at the specified conditions, shall be based on performance tests of actual or prototype equipment, including evase, if any, and inlet box(es). Parallel operation is allowed only on the continuously increasing portion of the curve.

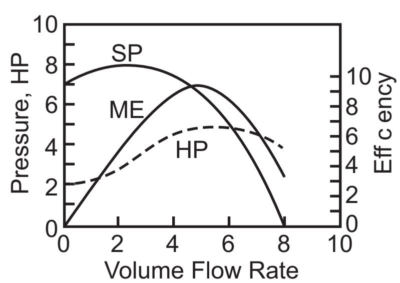
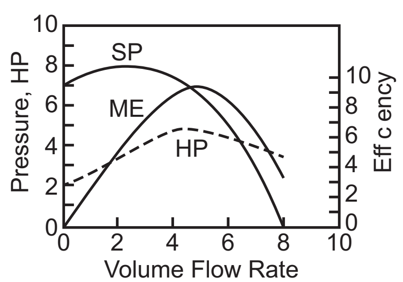
Airfoil		Highest efficiencies occur 50 % to 65 % of wide open volume. This is also the area of good pressure characteristics. The horsepower curve reaches a maximum near the peak efficiency area and becomes lower toward free delivery, a sell-limiting power characteristic as shown.	General heating, ventilating, and air-conditioning systems. Used in large sizes for clean-air industrial applications where power savings are significant.
Backward Inclined and Curved		Operating characteristics of this fan are similar to the airfoil fan mentioned above. Peak efficiency for this fan is slightly lower than the airfoil fan. Normally unstable left of peak pressure.	Same heating, ventilating, and air-conditioning applications as the airfoil fan. Also used in some industrial applications where the airfoil blade is not acceptable because of corrosive and/or erosion environment

Figure 29—Fan Characteristic Curves

The performance curves appearing in Figure 29 reflect general characteristics of types of fans commonly used in industrial fired boilers. They are not intended to provide complete selection criteria for application purposes, since other pertinent parameters are not defined.

8.5 Control Systems

- The fan may be controlled on the basis of inlet pressure, discharge pressure, flow rate, or some combination of these parameters. This may be accomplished by suction or discharge throttling or speed variation. The purchaser shall specify the type and source of the control signal, its sensitivity and range, and the equipment scope to be furnished by the vendor.

a) For constant-speed drive, the control signal shall actuate an operator that positions the inlet damper; the type of inlet damper shall be either a parallel blade or variable inlet guide vane (VIGV) damper.

b) For a variable-speed drive, the control signal shall act to adjust the set point of the driver's speed control system. Unless otherwise specified, the control range shall be from the maximum continuous speed to 95 % of the minimum speed required for any specified operating case, or 70 % of the maximum continuous speed, whichever is lower.

c) The full range of the purchaser's specified control signal shall correspond to the required operating range of the driven equipment. Unless otherwise specified, the maximum control signal shall correspond to the maximum continuous speed or the maximum flow rate.

d) Unless otherwise specified, facilities shall be provided to automatically open or close (as specified) the dampers or variable-inlet vanes on loss of control signal and to automatically lock or brake the dampers or vanes in their last position on loss of motive force (such as air supply or electric power). This is a specific system consideration and the associated controls shall be arranged to avoid creating hazardous or other undesirable conditions.

• e) Unless otherwise specified, the fan vendor shall furnish and locate the operators, actuator linkages and operating shafts for remote control of the dampers or variable-inlet vanes. Operator output shall be adequate for the complete range of damper or variable-inlet vane positions. The proposed location of operator linkages and shafts shall be reviewed with the purchaser for consideration of maintenance access and safety.

f) External position indicators shall be provided for all dampers or variable-inlet vanes.

Unless otherwise specified, pneumatic actuators shall be mechanically suitable for an air gauge pressure of 860 kPa (125 psi) and shall provide the required output with an air gauge pressure as low as 410 kPa (60 psi).

9 Boiler Feedwater Preparation

9.1 Makeup Water Type and Quality

9.1.1 General

Makeup water for industrial fired boilers for refinery and petrochemical service shall, when combined with return condensate, meet ASME guidelines. Makeup water may be pretreated by sodium zeolite softening, ion exchange demineralization with or without mixed bed polishing, reverse osmosis, or desalination. Feedwater type and quality, as well as the boiler pressure level and desired cycles, are used to determine the most appropriate treatment. In some cases a combination of these treatment processes is used. Fresh water is typically treated by softening, ion exchange demineralization or reverse osmosis. Brackish water may be treated by reverse osmosis followed by ion exchange demineralization or two-pass reverse osmosis. Seawater is treated by desalination or two-pass reverse osmosis, possibly followed by mixed bed polishing.

9.1.2 Softened Water

The term "softened water" indicates the removal of calcium and magnesium hardness only. With sodium zeolite softening, the calcium and magnesium ions are replaced with sodium ions. Sodium zeolite softening typically reduces hardness to less than 0.5 ppm (as $CaCO_3$). Total dissolved solids (TDS), silica, and alkalinity are not reduced. For high hardness, alkalinity, or silica feedwater, it may be economical to precede sodium zeolite softening by cold lime or hot lime softening. Cold lime softening reduces hardness and alkalinity, but reduces hardness only to the 20 ppm to 40 ppm (as $CaCO_3$) range and is, therefore, not sufficient for BFW makeup. Hot lime softening additionally reduces silica and dissolved oxygen, but again it alone does not reduce hardness to acceptable BFW levels. Feedwater that has gone through cold or hot lime softening will typically have a pH of 10 to 11. If sodium zeolite softening alone was used, the pH will be similar to the feedwater. Softened makeup water will typically only be acceptable for boilers under 4150 kPa (ga) [600 psi (ga)]. At higher pressures, the TDS in softened water will result in foaming and carryover in the boiler. Cycles in boilers receiving softened makeup water are typically limited by TDS, conductivity, alkalinity, or silica.

9.1.3 Demineralized Water

Ion exchange, including strong acid cation (SAC) resin and strong base anion (SBA) resin, is considered full demineralization and will be referred to as primary demineralization. FD or vacuum degasifiers can be used to reduce the CO_2 load on the SBA resin and, in the case of vacuum degasifiers, to reduce oxygen. Depending on the design, primary demineralization can produce water with 0.5 to 2 micro S/cm conductivity and 20 to 100 ppb of silica. The conductivity is primarily due to low level sodium slip from the SAC, which picks up hydroxide ions in the SBA. This type of feedwater can meet ASME guidelines for all but the highest pressure boilers (>8300 kPa (ga) [1200 psi (ga)]. For these boilers, mixed bed polishing is used. Mixed bed polishing typically achieves less than 0.5 micro S/cm conductivity and less than 20 ppb of silica. The pH from mixed bed demineralization is typically near neutral, but effluent from primary demineralizers is slightly basic.

9.1.4 Reverse Osmosis Water

Use of reverse osmosis as makeup water pretreatment of fresh or brackish water may be acceptable for boilers below 6200 kPa (ga) [900 psi (ga)], but will often limit cycles due to hardness or require post-treatment by softening or mixed bed polishing. Unless feedwater hardness is very low, in order to meet hardness guidelines, reverse osmosis units usually need to be preceded or followed by sodium zeolite softeners. Alternatively, two-pass reverse osmosis may achieve the specified quality. A typical reverse osmosis unit that recovers 75 % of the feedwater as permeate (product water) removes 95 % to 98.5 % of all ions. Dissolved gases, primarily CO_2 and O_2, are not removed by reverse osmosis. This means that unlike demineralization, which primarily leaks sodium and silica, reverse osmosis produced water will contain small amounts of all ions in the feedwater, as well as dissolved CO_2 and O_2. Demineralization also does not remove O_2, unless a vacuum degasifier is included. Since CO_2 passes through the reverse osmosis membrane, reverse osmosis produced water will typically be acidic. Alternatively, if softening is upstream of reverse osmosis, the feed pH can be increased to convert the CO_2 to bicarbonate so that it is removed. This also increases the reverse osmosis produced water pH. Piping materials between the reverse osmosis unit and degasifier or deaerator need to be considered carefully as the pH in the reverse osmosis produced water may be low. Boilers receiving reverse osmosis produced water as makeup may be limited by cycles, silica, hardness, alkalinity, or conductivity. Reverse osmosis produced water should not be used as attemperation water.

9.1.5 Desalinated Water

Seawater desalination by distillation or two-pass reverse osmosis may be used as boiler makeup. Distillation processes include thermal vapor compression and multiple effect distillation. Distillation produces lower conductivity (less than 5 micro S/cm) makeup water than does two-pass reverse osmosis, which ranges from 25 to 100 micro S/cm. NaCl makes up most of the conductivity, but there are also low levels of hardness, sulfate, alkalinity, and other ions. Since seawater contains very little silica, desalination water is also very low in silica, typically less than 100 ppb. These processes alone are acceptable for boilers under 6200 kPa (ga) [900 psi (ga)]. Mixed bed polishing is recommended for higher pressure boilers to ensure meeting conductivity limits and to provide protection against upsets. The pH of desalinated water produced by distillation should be near to neutral. Reverse osmosis produced desalinated water will be slightly acidic.

9.1.6 Applicability of Makeup Water Source to Boiler Pressure

Table 16 lists acceptable makeup water sources and pretreatment technologies based on boiler operating pressure. In addition water qualities listed in 9.5 shall be met.

9.2 Condensate Return and Treatment

Condensate return is desirable to reduce the amount of makeup water needed and to recover energy in the condensate. Condensate can improve the quality of BFW, especially where softened or reverse osmosis treated makeup water is used. Potential contaminants in condensate are hydrocarbons from exchanger leaks, TDS, including hardness and silica from cooling water leaks, iron and copper from corrosion, oxygen from surface condenser in leakage, CO_2 from alkalinity breakdown in the boiler, and trace amounts of sodium, phosphate, and silica from carryover and volatility in the boiler. Condensate, which has the potential to be contaminated with oil, usually goes through a tank to allow oil to separate. Condensate should always be returned to the deaerator to remove oxygen and CO_2 that may be present. Condensate will also contain residual neutralizing amines that were added to the BFW. Condensate and BFW should be sampled to ensure that the condensate does not adversely affect BFW quality. For higher pressure boilers, typically 6200 kPa (ga) [900 psi (ga)] and above, additional condensate treatment may be required. Activated carbon can be used to remove trace organics. Mixed bed polishers are used to remove metals (iron and copper), silica, and other trace inorganics. They will also remove neutralizing amines.

Table 16—Makeup Water Source to Boiler Pressure

		Boiler Pressure, kPa (ga) [psi (ga)]							
Raw Water Source	**Water Pretreatment**	**0 to 2070 (300)**	**2070 (301) to 3100 (450)**	**3100 (451) to 4150 (600)**	**4150 (601) to 5170 (750)**	**5170 (751) to 6200 (900)**	**6200 (901) to 6900 (1000)**	**6900 (1001) to 10,340 (1500)**	**10,340 (1501) to 13,800 (2000)**
Fresh	Na zeolite	A	A	A	RWD	NR	NR	NR	NR
Fresh	Reverse osmosis with Na zeolite	A	A	A	A	RWD	NR	NR	NR
Fresh	Demineralized	A	A	A	A	A	A	A*	NR
Fresh	Polished demineralized	A	A	A	A	A	A	A	A
Seawater	Two-pass seawater reverse osmosis	A	A	A	NR	NR	NR	NR	NR
Seawater	Desalinization	A	A	A	A	A	NR	NR	NR
Seawater	Polished desalination or polished two-pass seawater reverse osmosis	A	A	A	A	A	A	A	A

KEY

A = Acceptable.

A* = Acceptable up to 8275 kPa (ga) [1200 psi (ga)].

RWD = Raw water dependent.

NR = Not recommended.

9.3 Deaeration

Deaerators are used to remove dissolved gases from the makeup and condensate prior to it becoming BFW. The primary function is to mechanically remove the dissolved oxygen to very low ppb levels (e.g. 7 ppb) so chemical deaeration can ideally lower the dissolved oxygen levels to <2 ppb.

The five basic principles for effective mechanical deaeration are as follows.

— Ionization—Deaeration stripping cannot remove ionized molecules such as HCO_3^- or NH_4^+. This makes it difficult to remove chemicals that ionize in water. Oxygen does not ionize in water so its removal is very effective.

— Relative Partial Pressure—The deaerator steam is expected to have essentially 0 ppb of dissolved oxygen. When the makeup water and deaerating steam are mixed, the oxygen will be pulled from the water and into the steam.

— Temperature—The solubility of dissolved gases, such as oxygen, are a function of temperature and pressure. In the deaerator the steam raises the temperature of the water and should bring the temperature to within 1.7 °C to 2.2 °C (3 °F to 4 °F) of the saturated steam temperature. The solubility of oxygen in the water at these conditions will be approximately 7 ppb. Deaerators returning high-pressure condensate to the deaeration section may create slightly superheated conditions where the operating steam temperature is greater than the saturated steam temperature expected at the operating pressure.

— Agitation—To “free” the dissolved oxygen from the liquid, agitation is required. In deaerators this is achieved by using spray nozzles, steam scrubbing, and trays. These mechanical devices break the water into very small droplets and films allowing the oxygen to move to the steam.

— Stripping Steam—As the oxygen moves from the water phase to the steam it shall be removed from the system or it will re-dissolve in the water. This is accomplished by having an adequate flow of steam through the venting system. The vent plume should be a minimum height of 450 mm (18 in.). Some vents are equipped with a vent condenser. In these cases, the plume height will be reduced; however, there shall be sufficient positive venting for dissolved oxygen removal. The vent flow should be a minimum of 0.25 weight % of the BFW flow.

Table 17 shows the operating conditions needed for a mechanical deaeration process to lower the dissolved oxygen. There are three basic deaerator designs:

1) spray type,

2) spray/tray type,

3) atomizing type.

Table 17—Guidelines for Mechanical Deaeration Performance

Deaerator Type	Mechanical Oxygen Removal Efficiency [Effluent dissolved oxygen (DO) in ppb]	Minimum Water Flow (Percent of Design)	Minimum Steam Flow (Percent of Water Flow)	Minimum Temperature Delta makeup (MU) Water to Saturated Steam
Spray/tray	7 ppb	5	5	11 °C (20 °F)
Spray	20 to 50 ppb (see NOTE)	20	5	28 °C (50 °F)
Atomizing	20 to 50 ppb (see NOTE)	20	5	28 °C (50 °F)
NOTE Lower oxygen levels may be achieved depending on your specific design and operating conditions, but are not typical.				

Since spray/tray deaerators achieve the lowest dissolved oxygen levels, they are preferred for new designs and are the most frequently used design in the refining industry.

9.4 Chemical Treatment

9.4.1 General

The mechanical deaeration process removes the oxygen to very low levels (e.g. 7 ppb) in the deaeration section. If a spray deaerator is used, then higher levels of chemical oxygen scavenger are needed to reduce oxygen following mechanical deaeration. The water moves from the deaeration section to the storage section of the deaerator where chemistry is added for:

1) chemical deaeration,

2) BFW pH adjustment,

3) steam treatment.

Oxygen scavengers (listed in Table 18) are used to chemically remove oxygen not removed by mechanical deaeration. Dissolved oxygen can be aggressive for pitting corrosion in the BFW. Oxygen scavengers should be fed continuously. Dilution of oxygen scavengers is not recommended, as it increases deactivation rate. Amine chemistries (listed in Table 19) are used to adjust the pH of the deaerator storage water (BFW) and carries it through to the condensate.

Table 18—Oxygen Scavenger Chemistry

Oxygen Scavenger	Passivating/ Non-passivating (Note 1)	Volatile/ Non-volatile (Note 2)	Scavenging Temperature (Note 3) °F	Scavenging pH (Note 4)	Relative Reaction Time (Note 5)	BFW Residual Level ppm of active (Note 6)	Comment
Sodium bisulfite (catalyzed)	NP	NV	80 to 400	8.5 to 10.0	Fast	15 to 40 ppm in boiler water	Fast acting. Typically only used for softened water because it adds TDS.
Hydroquinone (HQ)	P	V	80 to 400	8.5 to 10.0	Fast	Positive in BFW	
Carbohydrazide	P	V	200 to 400	8.5 to 10.0	Moderate	Positive in BFW	
N, N-Diethyl-hydroxylamine (DEHA)	P	V	200 to 400	8.5 to 10.0	Moderate (fast if catalyzed with HQ)	Positive in BFW	
Erythorbic acid	P	V	200 to 400	8.5 to 10.0	Moderate	Positive in BFW	FDA approved or nitrogen restrictions
Sodium erythorbate	P	NV	200 to 400	8.5 to 10.0	Moderate	Positive in BFW	FDA approved or nitrogen restrictions
Hydrazine	P	V	200 to 400	8.5 to 10.0	Moderate	Positive in BFW, 0.05 to 0.1 ppm as N_2H_2	Suspected carcinogen. Typically replaced by carbohydrazide

NOTE 1 Oxygen scavengers are classified into two basic categories: passivating (P) and non-passivating (NP). Passivating scavengers act as catalyst to speed the formation of the protective magnetite film. Non-passivating scavengers do not accelerate the magnetite filming process. Oxygen scavengers have varied passivating capabilities. Those capabilities should be discussed with your water treatment expert.

NOTE 2 Non-volatile (NV) oxygen scavengers are acceptable for softened water systems. Volatile (V) oxygen scavengers should be used for high purity water BFW.

NOTE 3 Oxygen scavenger reaction rates are ideally carried out in the posted temperature range. At lower temperatures the reaction rates are slower. At temperatures >205 °C (400 °F) scavengers will begin to thermally decompose. Sulfite and hydroquinone function at temperatures down to 27 °C (80 °F), but a deaerator would not be operated down in this range. Check with your water treatment expert for temperature related information.

NOTE 4 Oxygen scavenger performance is pH dependent. Optimum scavenger performance is at a pH of 9.0 to 9.6. However, most BFW is in the 8.5 to 10 range. Your water treatment expert should be consulted if you will be operating outside the 8.5 to 10.0 pH range. Neutralizing amines are most frequently used to adjust the deaerator water pH. In some cases, such as sodium zeolite or reverse osmosis feedwater, caustics may be used as well.

NOTE 5 Oxygen scavenging reactions are time dependent. A 10 min time is the recommended minimum. Shorter reaction times will reduce the percent removal efficiency.

NOTE 6 Non-sulfite oxygen scavengers maintain a positive residual (excess) in the BFW. Your water treatment expert should be consulted for the specific residual to maintain and analysis method to use.

Table 19—Deaerator/BFW Amine Chemistry

Amine (Note 1) Formula Molecular Weight	**Vapor/Liquid Distribution Ratio at the Specified Pressure (Note 2)** kPa (ga) [psi (ga)]					**Neutralizing Requirement (Note 3)**	**pKa**	**FDA Approved**
	70 (10)	350 (50)	1035 (150)	4150 (600)	6200 (900)	Amine ppm/ ppm CO_2 (as CO_2)	Basicity (Note 4)	
Ammonia (Note 5) NH_3 17	3.0	6.7	7.0	5.0	4.3	0.4	9.3	Yes
Ethanolamine (MEA) C_2H_7NO 61	0.004	0.01	0.05	0.21	0.21	1.4	9.4	No
Morpholine (MOR) C_4H_9NO 87	0.4	0.44	0.5	1.2	1.2	2.0	8.4	Yes
Methoxypropyl-amine (MOPA) $C_4H_{11}NO$ 89	0.6	0.8	1.3	2	2	2.0	10.1	No
Diethylamino-ethanol (DEAE) $C_6H_{15}NO$ 117	2.2	3.0	4.3	5.2	4.5	2.7	9.8	Yes
Cyclohexylamine (CHA) $C_6H_{13}N$ 99	2.7	3.0	4.0	10	6.6	2.3	10.7	Yes
Carbon dioxide CO_2 44 (Note 1)	3.0	4.8	8.5	15.8	99.0	NA	6.4	NA

NOTE 1 The listed amines are the most frequently used. There are other amines that are used for pH elevation and neutralization in steam generation. Your water treatment expert will be able to provide the information on amine chemistry not listed. CO_2 is what is typically being neutralized. Its properties are shown for comparison.

NOTE 2 Amine transport is determined by its vapor/liquid (V/L) ratio. This ratio is pressure (temperature) dependent. The selection of amine chemistry will be based on the pressures in the system. Amine V/L ratio is also pH dependent. The standard amine V/L ratios listed are done with the expectation that the pH will be in the normal range (8 to 11) for steam generation systems. If the pH is outside of the normal range, contact your water treatment expert.

NOTE 3 Carbonic acid (carbon dioxide) is the most frequently neutralized acid in steam generation systems. Organic acids, SO_2, H_2S, etc. contaminations will put additional demand on the treatment. You should contact your water treatment expert for the amine requirement for neutralization.

NOTE 4 After neutralization, the steam system water (BFW, boiler water, and condensate) pH elevation will be dependent on the basicity of the amine. The higher the basicity, the higher the pH elevation/ppm of amine. For example, 1 ppm of cyclohexylamine (after neutralization) will elevate the pH to a higher level than 1 ppm of morpholine. The pKa is the equilibrium point where 50 % of the molecular amine is ionized.

NOTE 5 Ammonia causes copper corrosion in the presence of oxygen.

Amine chemistry is used to manage the pH of the deaerator storage section (BFW) and condensate(s). Amines are volatile and are transported into the steam as governed by vapor to liquid (V/L) ratio. The V/L ratios are pressure (temperature) dependent so the selection is influenced by the system operating pressures.

Amines are used to neutralize acidic materials in the steam system. The contaminant that the amine(s) are generally neutralizing is carbonic acid. The neutralizing capacity of the amine is based on its molecular weight.

After the neutralizing reaction the remaining amine will elevate the pH of the BFW or condensate. The ability to elevate the pH is based on the amines pKa. The higher the pKa the greater the pH elevation will be per ppm of amine.

9.4.2 Deaerator Chemical Addition Facilities

Chemical addition facilities consist of storage tanks, pumps, flow measurement and control facilities, piping, block and check valves, and injection quills for injection into a line or distribution headers for injection into a vessel. Materials of construction shall be consistent with the product being fed to avoid corrosion. Oxygen scavengers and amines should be fed neat (undiluted). Pumps should be sized to allow good control at the range of operation. Pumps are generally positive displacement metering pumps. Flow measurement consists of a drawdown gauge. Pump speed and/or stroke are adjusted to control flow manually or automated based on a flow or analytical signal. Monitoring of the chemical injection system should include checking tank level, pump operating status, and drawdown or other flow indication.

9.5 Boiler Feedwater Quality

BFW quality limits are set to control the level of corrosive and deposit forming chemistry in the water. The primary focus is on a few elements that cause the majority of corrosion and scale found in steam generation systems. Table 20 lists suggested BFW chemistry limits.

— Hardness—Hardness (calcium and magnesium) has an inverse solubility with temperature and form hard deposits in steam generators. Any hardness that enters the steam generator can result in deposition. Chemical treatments reduce the hardness scaling potential, but they can only effectively manage low ppb levels. The BFW hardness limits are based on the “normal” amount of contamination that chemical treatments manage.

— Iron and Copper—Iron and copper are generally corrosion products that are transported in the steam generation system. Polymers are added to the internal treatment program to help keep iron in solution/suspension to allow the material to leave with the boiler water blowdown. Still, most of the iron and copper that enters the steam generator will be deposited. About 80 % of the incoming iron and essentially all of the copper is deposited in the boiler. The BFW limit is based on the contamination level needed to keep deposition densities <4 to 6 grams/ft^2/year.

— Non-volatile Total Organic Carbon (TOC) and Oil and Grease—Non-volatile TOC and oil and grease will cause organic deposition in the boiler and the steam circuit. There are no internal chemistry treatments for non-volatile TOC and oil and grease. Even small amounts of these types of contaminants will cause problems with steam purity and boiler heat transfer.

— Dissolved Oxygen—Dissolved oxygen can cause corrosive pitting in a carbon steel pre-boiler system. A combination of mechanical deaeration and chemical oxygen scavenging are used to remove dissolved oxygen from the BFW.

— pH—pH is controlled to minimize corrosion. The solubility of iron and copper is pH dependent. The solubility of iron and copper not only increase the potential for corrosion failure, but increase the deposition potentials in the steam generator.

Table 20—Suggested Boiler Feedwater Chemistry Limits (Note 1)

Drum Operating Pressure kPa (ga) [psi (ga)]	**0 to 2070 (300)**	**2070 (301) to 3100 (450)**	**3100 (451) to 4150 (600)**	**4150 (601) to 5170 (750)**	**5170 (751) to 6200 (900)**	**6200 (901) to 6900 (1000)**	**6900 (1001) to 10,340 (1500)**	**10,340 (1501) to 13,800 (2000)**
Feedwater Quality								
Dissolved oxygen (ppb as O_2) before chemical oxygen scavenger	<7	<7	<7	<7	<7	<7	<7	<7
Total iron (ppb as Fe)	<100	<50	<30	<25	<20	<20	<10	<10
Total copper (ppb as Cu)	<50	<25	<20	<20	<15	<10	<10	<10
Nonvolatile TOC (ppm) (Note 4)	<1	<1	<0.5	<0.5	<0.5	<0.2	<0.2	<0.2
Oil and grease (ppm)	<1	<1	<0.5	<0.5	<0.5	<0.2	<0.2	<0.2
Feedwater Quality for Systems Using Softened or Reverse Osmosis Permeate Makeup Water (Note 2)								
pH @ 25 °C	8.5 to 10.0	8.5 to 10.0	8.5 to 10.0	8.5 to 10.0	NR	NR	NR	NR
Conductivity micro S/cm (Note 5)	NA	NA	NA	NA	NR	NR	NR	NR
Total hardness (ppb as $CaCO_3$)	<300	<300	<200	<200	NR	NR	NR	NR
Feedwater Quality for Systems Using High Purity Makeup Water (Note 3)								
pH @ 25 °C (Note 6)	8.8 to 9.6	8.8 to 9.6	8.8 to 9.6	8.8 to 9.6	8.8 to 9.6	8.8 to 9.6	8.8 to 9.6	8.8 to 9.6
Conductivity micro S/cm (Note 5)	<4	<4	<2	<2	<1	<0.5	<0.5	<0.5
Total hardness (ppb as $CaCO_3$)	<50	<50	<50	<50	<50	ND10	ND10	ND10

NOTE 1 Guidelines are adapted from ASME CRTD Volume 34. Consistent with ASME, boilers with local heat fluxes >473.2 kW/m^2 [>1.5 × 10^5 Btu/(h-ft^2)], should use values for at least the next higher pressure range. The main difference is that this table includes separate guidelines for systems using sodium zeolite softened or reverse osmosis permeate as makeup vs systems using high purity makeup water. NA means not applicable. ND10 means non-detect with a detection limit of 10 ppb. NR means not recommended.

NOTE 2 Softened water includes sodium zeolite, cold lime softened followed by sodium zeolite, and hot lime softened followed by sodium zeolite.

NOTE 3 High purity water includes thermally desalinated waters, demineralized waters, high purity condensates, or two-pass reverse osmosis if it meets the conductivity and hardness criteria. High purity water has ultralow hardness (<50 ppb as $CaCO_3$).

NOTE 4 Excludes treatment chemistries.

NOTE 5 Conductivity excludes the contr bution of amines.

NOTE 6 For systems with yellow metal, the upper pH limit is 9.2. pH range needs to be consistent with meeting the iron target, so may need to be tighter at higher pressure ranges.

9.6 Deaerator/BFW Monitoring and Control

9.6.1 General

Table 21 and Table 22 show recommended monitoring and control guides for deaerators and BFW.

Table 21—Deaerator Mechanical Performance Monitoring and Control

Deaerator Monitoring/Control	Location	Type	Frequency
Temperature	Deaeration section (steam)	Calibrated local gauge (Note 1)	Verification (Note 2)
		Calibrated control room gauge	Continuous
	Storage section (water)	Calibrated local gauge (Note 1)	Verification (Note 2)
		Calibrated control room gauge	Continuous
	Condensate	Calibrated local or control room gauge	Continuous
Pressure	Deaeration section (steam)	Calibrated local gauge	Verification
		Calibrated control room gauge	Continuous
	Storage section (water)	Calibrated local gauge	Verification
		Calibrated control room gauge	Continuous
Mass steam flow	Steam inlet	Flow meter	Continuous
	BFW, deaerator outlet (Note 3)	Flow meter	Continuous
	Makeup water	Flow meter	Continuous
Dissolved oxygen	Influent steam	Temporary online analyzer	Troubleshooting (Note 4)
	Deaerator outlet drop leg	Temporary online analyzer	Troubleshooting (Note 5)
Steam flow control	Steam inlet	Modulating control valve on deaerator pressure control	Continuous
Makeup water control	Makeup water inlet	Modulation control valve on deaerator level	Continuous

NOTES 1 & 2 The temperature delta between the deaerating steam section operating temperature and the saturated steam temperature should be 1.7 °C to 2.2 °C (3 °F to 4 °F) under normal conditions. Local gauges need to be properly ranged and calibrated to get a reliable analysis for a meaningful verification of deaerator performance.

NOTE 3 The deaerator outlet mass flow can be calculated by knowing the flow rates of all waters and steam coming to the deaerator. Vented steam flow shall be estimated.

NOTE 4 Deaerator inlet steam is not typically monitored on a continuous basis. The selection of the steam source is important. Boiler blowdown flash tank steam is considered to have a very low potential for contamination. Saturated and superheated header steams have a higher contamination potential because of oxygen contaminated BFW and air in-leakage.

NOTE 5 Typical monitoring location is downstream of the BFW pump. Additional analysis in the deaerator drop leg is for troubleshooting the deaerator or to compare vs downstream of the pump if in-leakage is suspected.

Table 22—Deaerator/Boiler Feedwater Monitoring

Chemical Test (Note 1)	Monitoring Purpose	Sample Analysis Performed	Frequency
Sample Location: Downstream of BFW Pump			
Dissolved oxygen	Chemical oxygen removal efficiency	Online	Continuous
	Deaeration efficiency		
	Oxygen in-leakage		
Oxygen scavenger residual (Note 2)	Excess oxygen scavenger	Lab	Weekly or more frequent if online DO analyzer is not available
	Deaeration efficiency		
Internal treatment (Note 3)	Level of internal treatment	Lab analysis of active ingredient or tracer (Notes 6 and 7)	Once/shift
	Deposition and corrosion potential		
pH	Corrosion potential of BFW	On-line with temperature correction	Continuous
Temperature (Note 4)	Sample temperature for pH correction and safety	Online	Continuous
Conductivity	For cycle calculation with softened makeup water	Online	Continuous
Total iron	Corrosion product	Lab	Once/week
	Iron fouling potential		
Soluble Fe^{+2} iron	Active corrosion product, iron fouling potential	Lab	Once/week
Total copper	Corrosion product	Lab	Once/week
	Copper fouling potential		
Total hardness	Scale and sludge forming ions, deposit potential	Lab (Notes 8 and 9)	Once/shift for softened/reverse osmosis water. Once/week for high purity water.
A kalinity (Note 5)	For softened or reverse osmosis water to determine alkalinity contr bution of BFW	Lab	Once/week or more frequently if needed due to variability
	Boiler water OH^- a kalinity level		
	Carbon dioxide generation potential		
Silica	Diagnostics for cycling, indication of condensate contamination or demineralized performance issues	Lab (Note 8)	Once/shift (Note 10)
Sample Location: Downstream of Economizer			
Total iron	Corrosion product	Lab	Troubleshooting
	Iron fouling potential		
Soluble Fe^{+2} iron	Active corrosion product level	Lab	Troubleshooting
	Dissolved oxygen corrosion potential		
	BFW chemistry corrosion potential		

NOTE 1 These are generic tests. Specific test methods should be selected based on detection limits, interferences, etc. The choice of test method(s) should be discussed with your water treatment expert.

NOTE 2 For all oxygen scavengers except sulfite, which is monitored in the cycled up boiler water.

NOTE 3 Internal chemical treatments will vary greatly depending on the BFW quality, boiler operating pressure and steam requirements. Chelant residual may be checked in the boiler feedwater, but should be non-detect. Polymer levels and polymer tracer levels are measured in the boiler feedwater or boiler water, depending on the concentration and ability to measure. PO_4 for congruent or residual phosphate treatment is monitored in the boiler water.

NOTE 4 For high purity water, temperature compensation within the analyzer is needed to correct pH to 25 °C (77 °F). Water chemistry applications have sample temperatures adjusted to 25 °C (77 °F) as a standard.

NOTE 5 OH^- or “O” alkalinity testing should be done using the BaCl method.

NOTE 6 Inert tracing agents may be used to verify product levels. Tracing agent selection should be discussed with your water treatment expert.

NOTE 7 Internal chemical treatments will vary greatly depending on the BFW quality, boiler operating pressure and steam requirements. Chelant is monitored in the BFW. PO_4 for congruent or residual phosphate treatment and polymer for all-polymer treatment are monitored in the boiler water.

NOTE 8 These tests are most frequently done in the lab (grab samples). However, online analyzers are available.

NOTE 9 Low level hardness analysis with a detection limit as low as the water hardness limit is needed for monitoring.

NOTE 10 Demineralized water silica analysis should be continuous.

9.6.2 Sample Conditioning System

BFW, boiler water, condensate, and steam samples require sample conditioning systems. Figure 30 shows a sample conditioning system, which should include the following, adapted from ASME CRTD Volume 81.

a) Stainless steel or equivalent metallurgy for all sample lines, valves, and coolers.

b) Sample flow rates should be for 1.27 m/s to 1.52 m/s (5 ft/s to 6 ft/s).

c) Sample flow adjustment should always be on the outlet of the cooler.

d) Sample temperatures should be as close to 25 °C (77 °F) as possible. Samples should have a maximum temperature of 38 °C (100 °F). This is for safety and testing accuracy.

e) Sample line filters should not be used except before analyzers that require filters to protect the analyzer.

f) Steam samples additionally require isokinetic sampling nozzle and flow control. See Section 11.

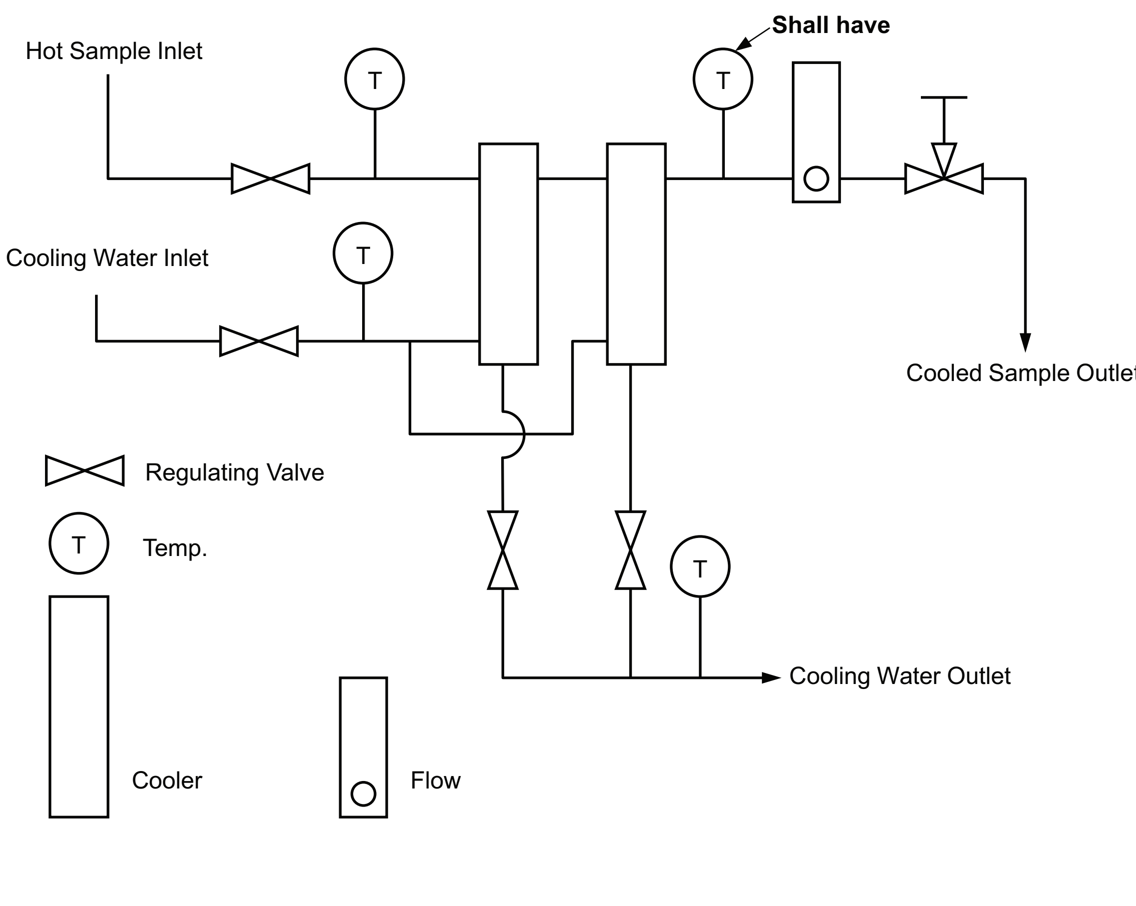


Figure 30—Boiler Feedwater, Boiler Water, Condensate, and Steam Sample Conditioning System

10 Boiler Water Quality and Internal Chemical Treatment

10.1 Boiler Water Quality

Boiler water quality limits are set to control steam purity, internal boiler corrosion and internal deposition. Table 23 lists suggested boiler water chemistry limits based on boiler operating pressure. Limiting parameters are as follows:

— Silica—Maximum silica limits are set for the boiler water based on pressure (temperature). Silica is volatile and its volatility increases with pressure. The maximum boiler water level is set to keep the volatile silica in the steam to <20 ppb.

— Total Alkalinity—Total alkalinity is the $CO_3^{=}$ and OH^{-} alkalinity level in the boiler water. Maximum total alkalinity limits are set to maintain steam purity. High alkalinity levels will promote boiler water foaming, which allows boiler water to contaminate the steam. Total alkalinity limits are based on pressure. As the pressure increases, the maximum total alkalinity limit decreases.

— Conductivity—Conductivity is an indicator of the boiler water TDS. Maximum conductivity (TDS) levels are set to maintain steam purity and control boiler corrosion. High conductivity levels will promote boiler water foaming and indicate high levels of aggressive anions, such as chloride, and will increase the corrosion potential in the boiler. Some boiler waters can contain high levels of hydroxide alkalinity. Hydroxide alkalinity is highly conductive (approximately 3X) when compared to other dissolved materials such as NaCl. Conductivity limits are without neutralization, however. The boiler water hydroxide can be neutralized to get a closer indication of the TDS. The conductivity limits are based on pressure. As the pressure increases the maximum conductivity decreases.

— Cycles—Cycles of concentration show the number of times the chemicals in the BFW are being concentrated. As an example, ten cycles of concentration would mean 1 ppm of SiO_2 in the BFW should be 10 ppm of SiO_2 in the boiler water. Other highly soluble ions (Na, K, Cl, nitrates) and/or inert tracing agents are often used to verify cycles because some chemistries may precipitate out of solution or flash over with the steam. Conductivity or chloride ion is used for cycle calculations in generators using high conductivity (softened) BFW.

  Overcycling increases the holding time index. This represents the physical time the chemistry stays in the steam generator. Boilers operate at high temperature and have two-phase flow. The longer a chemical stays in this environment the more likely it is to deposit or decompose.

10.2 Internal Chemical Treatment

10.2.1 General

Internal treatment chemistry is added to the steam generator to control deposition and corrosion. There are five general categories for internal treatment. Three of these are used frequently in industrial operations.

a) Residual phosphate.

b) Complexing chemistry (chelant/polymer and all-polymer).

c) Congruent pH/PO_4.

The following two categories are not generally recommended for industrial operations because they require ultrahigh purity water (<0.2 micro S/cm cation conductivity at all times). These programs are:

a) continuum phosphate,

b) all volatile treatment (AVT).

A water treatment expert should be consulted prior to using a continuum phosphate or AVT program. These programs have virtually no buffering and are, therefore, only applicable with ultrahigh purity feedwater. This lack of buffering increases the risk of the boiler water pH quickly becoming acidic, resulting in rapid corrosion damage.

Table 23—Suggested Boiler Water Chemistry Limits (Note 1)

Drum Operating Pressure (Note 2) kPa (ga) [psi (ga)]	**0 to 2070 (300)**	**2070 (301) to 3100 (450)**	**3100 (451) to 4150 (600)**	**4150 (601) to 5170 (750)**	**5170 (751) to 6200 (900)**	**6200 (901) to 6900 (1000)**	**6900 (1001) to 10,340 (1500)**	**10,340 (1501) to 13,800 (2000)**
All Systems Regardless of Feedwater Source								
Silica (ppm as SiO_2)	<150	<90	<40	<30	<20	<8	<2	<1
Boiler Water Quality for Systems with Softened or Reverse Osmosis Water BFW Makeup (Note 3)								
Specific conductance without neutralization, micro S/cm (Note 4)	<5400	<4600	<3800	<1500 (Note 5)	NR	NR	NR	NR
Total alkalinity (ppm as $CaCO_3$) (Note 6)	<700	<500	<400	<200	NR	NR	NR	NR
Boiler cycles	<50	<50	<50	<50	NR	NR	NR	NR
Boiler Water Quality for Systems with High Purity BFW Makeup								
Specific conductance without neutralization, micro S/cm (Note 7)	<500	<400	<350	<300	<200	<150	<150	<80
Total alkalinity (ppm as $CaCO_3$) (Note 8)	See internal treatment program							
Boiler cycles	<100	<100	<100	<100	<100	<100	<100	<100

NOTE 1 Guidelines are adapted from ASME CRTD Volume 34. Differences have been highlighted and reflect segregation by makeup water type, e.g. sodium zeolite or reverse osmosis permeate vs high purity makeup water. Consistent with ASME, boilers with local heat fluxes >473.2 kW/m^2 [>1.5 × 10^5 Btu/(h-ft^2)], should use values for at least the next higher pressure range.

NOTE 2 System operation is dictated by the first maximum limit to be reached. Steam purity limits may limit a system from operating at maximum levels.

NOTE 3 NR means that softened or reverse osmosis makeup is not recommended for this pressure level.

NOTE 4 Maximum values are often not achievable without exceeding maximum total alkalinity values, especially in boilers below 6200 kPa (ga) [900 psi (ga)] 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 shall 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.

NOTE 5 Acceptable up to 4500 kPa (ga) [650 psi (ga)].

NOTE 6 Maximum total a kalinity consistent with acceptable steam purity. If necessary, should override conductance as blowdown control parameter. A kalinity values in excess of 10 % of specific conductance may cause foaming. Values for 2070 kPa (ga) to 4500 kPa (ga) [300 to 650 psi (ga)] boilers are tighter than ASME, but consistent with the 10 % of specific conductance guideline. Minimum hydroxide a kalinity concentrations shall be individually specified by a qualified water treatment consultant with regard to silica solubility and other components of internal treatment.

NOTE 7 Low-pressure boilers frequently use feedwater that is suitable for use in higher pressure boilers. In these cases the boiler water chemistry limits should be based on the pressure range that is most consistent with the feedwater quality.

NOTE 8 Non-detectable free sodium or potassium hydroxide alkalinity. Some small variable amount of total a kalinity will be present and measureable with the assumed congruent or coordinated phosphate pH control. See later sections on congruent phosphate control.

10.2.2 Residual Phosphate Treatment

These treatment programs are used in steam generators <4500 kPa (ga) [<650 psi (ga)] for systems with softened or reverse osmosis makeup water. They precipitate calcium hardness with orthophosphate and magnesium hardness with silica and hydroxide alkalinity. This hardness sludge is insoluble and shall be dispersed in the water and removed through the continuous and intermittent blowdown. Insoluble sludge and metals (iron and copper) that precipitate on the heat transfer surface as a result of steam generation cannot re-wet so they remain on the heat transfer surface. Table 24 lists suggested limits for parameters associated with residual phosphate internal treatment.

Table 24—Residual Phosphate Internal Treatment (Note 1)

Drum Operating Pressure kPa (ga) [psi (ga)]	**0 to 2070 (300)**	**2070 (301) to 3100 (450)**	**3100 (451) to 4150 (600)**	**4150 (601) to 5170 (750)**	**5170 (751) to 6200 (900)**	**6200 (901) to 6900 (1000)**	**6900 (1001) to 10,340 (1500)**	**10,340 (1501) to 13,800 (2000)**
Filtered (0.2 micron) ortho phosphate (as PO_4)	30 to 60	30 to 60	20 to 40	20 to 40	NR	NR	NR	NR
pH @ 25 °C (Note 2)	10.5 to 11.5	10.5 to 11.5	10.5 to 11.5	10.5 to 11.5	NR	NR	NR	NR
Hydroxide (as $CaCO_3$) (Note 3)	250 to 500	150 to 400	150 to 350	100 to 175	NR	NR	NR	NR
Hydroxide/silica ratio minimum	3:1	3:1	3:1	3:1	NR	NR	NR	NR
Cycles	50 max	50 max	50 max	50 max	NR	NR	NR	NR

NOTE 1 All other boiler water chemistry limits such as silica, conductivity, etc. shall be observed. Boiler water chemistry is limited by the first chemical parameter to reach its maximum limit.

NOTE 2 pH is a target, but hydroxide range is controlling.

NOTE 3 Hydroxide shall be run with a barium chloride method, which is titrating to the phenolphthalein endpoint after carbonate is precipitated with barium chloride.

10.2.3 Complexing Chemistry Treatments

Complexing treatment programs are used in steam generators <4500 kPa (ga) [<650 psi (ga)] for systems with softened or reverse osmosis makeup water. They chelate calcium and magnesium hardness ions. The complexing agents keep the calcium and magnesium soluble. These programs can have 100 % transport of hardness. Chelant/polymer and all-polymer chemistries are the most common programs. Table 25 lists suggested limits for parameters associated with complexing chemistries. Your water treatment expert should be consulted when selecting these chemistries.

Table 25—Complexing Internal Treatment (Note 1)

Drum Operating Pressure kPa (ga) [psi (ga)]	**0 to 2070 (300)**	**2070 (301) to 3100 (450)**	**3100 (451) to 4150 (600)**	**4150 (601) to 5170 (750)**	**5170 (751) to 6200 (900)**	**6200 (901) to 6900 (1000)**	**6900 (1001) to 10,340 (1500)**	**10,340 (1501) to 13,800 (2000)**
Complexing chelant and/or polymer, percent of stoichiometric (Note 2)	~120	~120	~120	~120	NR	NR	NR	NR
Hydroxide (as $CaCO_3$) (Note 3)	50 to 300	50 to 250	50 to 200	50 to 175	NR	NR	NR	NR
Cycles	50 max	50 max	50 max	50 max	NR	NR	NR	NR

NOTE 1 All other boiler water chemistry limits such as silica, conductivity, etc. shall be observed. Boiler water chemistry is limited by the first chemical parameter to reach its maximum limit.

NOTE 2 Complexing internal treatments are chelants [ethylenediaminetetraacetic acid (EDTA) or similar low molecular weight molecules] and/or polymers. Chelants are typically combined with polymer. While the treatment level desired is approximately 120 % of the required stoichiometric level needed to complex feedwater contaminants, chelants are typically fed sub to stoichiometric, and polymer comprises the remaining amount. Alternatively, polymer may be used alone. Since there are several types of complexing chemistries available, application of these chemistries should be discussed with your water treatment expert.

NOTE 3 Complexing chemistry requires minimum levels of hydroxide alkalinity. Applications of these chemistries at hydroxide levels below the 50 ppm minimum should be discussed with your water treatment expert. Hydroxide should be run with a barium chloride method, which is titrating to the phenolphthalein endpoint after carbonate is precipitated with barium chloride.

10.2.4 Congruent pH/PO_4

This program is used for high purity water. High purity water includes thermally desalinated waters, demineralized waters, high purity condensates, and two-pass reverse osmosis if it meets the conductivity and hardness criteria in 9.5. High purity water has ultralow hardness (<50 ppb as $CaCO_3$). Congruent pH/PO_4 is a corrosion control program. It does the following:

a) prevents "free caustic" corrosion,

b) buffers the pH of the boiler water from acidic or caustic contamination.

c) maintains the bulk boiler water pH in the minimum corrosion range.

Table 26 lists suggested limits for parameters associated with congruent pH/PO_4 treatment.

Table 26—Congruent pH/PO_4 Treatment (Note 1)

Drum Operating Pressure kPa (ga) [psi (ga)]	**0 to 2070 (300)**	**2070 (301) to 3100 (450)**	**3100 (451) to 4150 (600)**	**4150 (601) to 5170 (750)**	**5170 (751) to 6200 (900)**	**6200 (901) to (1000)**	**6900 (1001) to 10,340 (1500)**	**10,340 (1501) to 13,800 (2000)**
Orthophosphate (as PO_4)	20 to 40	20 to 30	20 to 30	10 to 25	10 to 25	10 to 25	10 to 20	5 to 10
Na:PO_4 molar ratio	2.6 to 3.0	2.2 to 3.0	2.2 to 2.8	2.2 to 2.8	2.2 to 2.8	2.2 to 2.8	2.2 to 2.8	2.2 to 2.8
pH @ 25 °C (Note 2)	9.6 to 10.5	9.6 to 10.4	9.6 to 10.4	9.4 to 10.2	9.4 to 10.2	9.4 to 10.2	9.4 to 10.0	9.2 to 9.8
Cycles (Note 3)	100 max	100 max	100 max	100 max	100 max	100 max	100 max	100 max

NOTE 1 Congruent pH/PO_4 chemistry is controlled between Na:PO_4 curves plotted on a pH/PO_4 graph. The pH values on this chart are referenced to 25 ºC (77 ºF). It is important that pH values are corrected to 25 °C (77 °F) when graphing data on a congruent pH/PO_4 chart.

NOTE 2 The pH range identifies the lower left and upper right corner of the box. The box is actually defined by the PO_4 range and the Na:PO_4 curves. See Figure 31 and Figure 32.

NOTE 3 Cycles calculation and control are discussed in the next section. The maximum conductivity, a kalinity and SiO_2 chemistry limits posted for boiler water quality can produce extremely high cycles (low blowdown) that are well above the maximum. Therefore, the maximum recommended cycles of 100 should be obeyed even if conductivity, alkalinity, or silica limits would allow higher cycles. In this case, lower target values for SiO_2, conductivity and alkalinity should be set so as not to exceed maximum cycles.

10.2.5 Chemical Addition Facilities

Chemical addition facilities consist of storage tanks, pumps, flow measurement and control facilities, piping, block and check valves, and injection quills for injection into a line or distribution headers for injection into a vessel. Materials of construction shall be consistent with the product being fed to avoid corrosion. Chelant and polymer products (complexing chemistries) are added to the BFW neat (undiluted). Alkaline phosphate and congruent phosphate products are added to the steam drum below the low liquid level or to the BFW line, downstream of any attemperation water takeoff. Phosphate products added to the steam drum should be diluted to about 0.4 % phosphate to avoid plugging in the internal distribution piping. Pumps should be sized to allow good control at the range of operation. Pumps are generally positive displacement metering pumps. Flow measurement consists of a drawdown gauge. Pump speed and/or stroke are adjusted to control flow manually or automated, based on a flow or analytical signal. Monitoring of the chemical injection system should include checking the tank level, pump operating status, and drawdown or other flow indication.

10.3 Boiler Cycles

Boiler cycles are the ratio of BFW rate to boiler blowdown rate, which set the cycles of concentration in the boiler water. Boiler blowdown is used to control the concentration of feedwater ions and internal treatment chemistry in the boiler water. Boiler blowdown, or boiler cycle control, is critical to preventing scale and corrosion in the boiler. This control is often manual, but there are several ways to automate it, as discussed below. It is also important to conserve water and energy by operating at the highest cycles possible. However, when increasing cycles above 50, there are diminishing returns for water and energy savings. See Figure 33.

Boiler water cycles are set with an upper and lower limit. The upper limit is set to water chemistry and holding times. When the upper limit is exceeded, steam purity, deposition and corrosion potentials increase. When the lower limit is exceeded, unnecessary water and energy losses occur, increasing operating cost. At low cycles chemical treatments may drop below their minimum levels for protecting the system against deposition and corrosion.

To determine cycles of concentration in the steam generator, flow of the steam and boiler blowdown, or components in the BFW and boiler water, shall be accurately measured. The calculated cycles give the percent blowdown.

Common Boiler Water Calculations

cycles = boiler water ion/BFW ion

percent blowdown = 100/cycles

blowdown rate = steam rate/(cycles – 1)

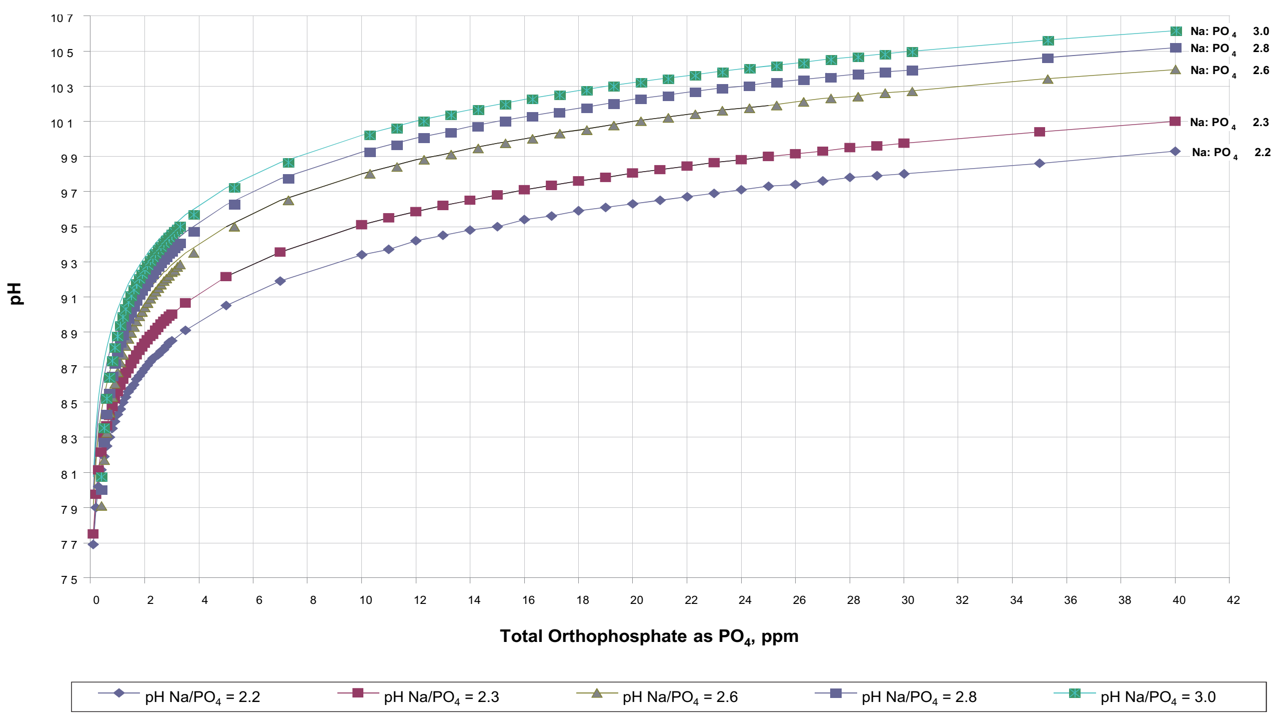


Figure 31—pH vs PO_4 Graph at Different Na/PO_4 Ratios

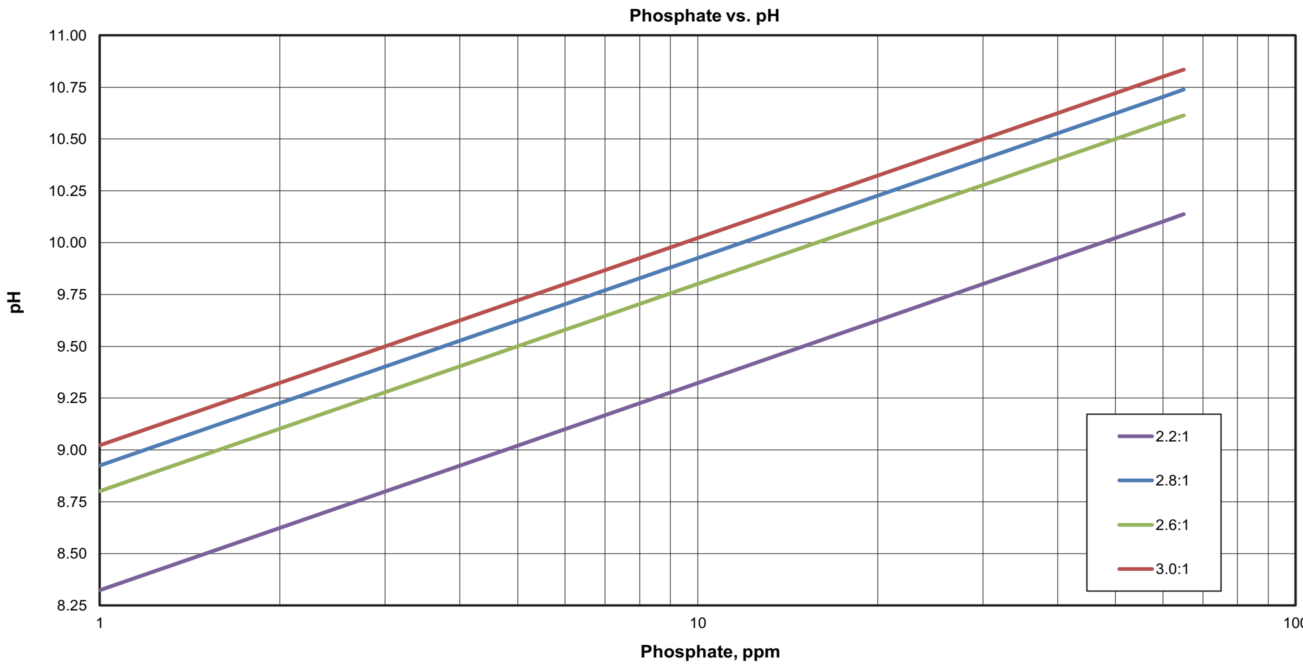


Figure 32—pH vs log PO_4 Graph at Different Na/PO_4 Ratios

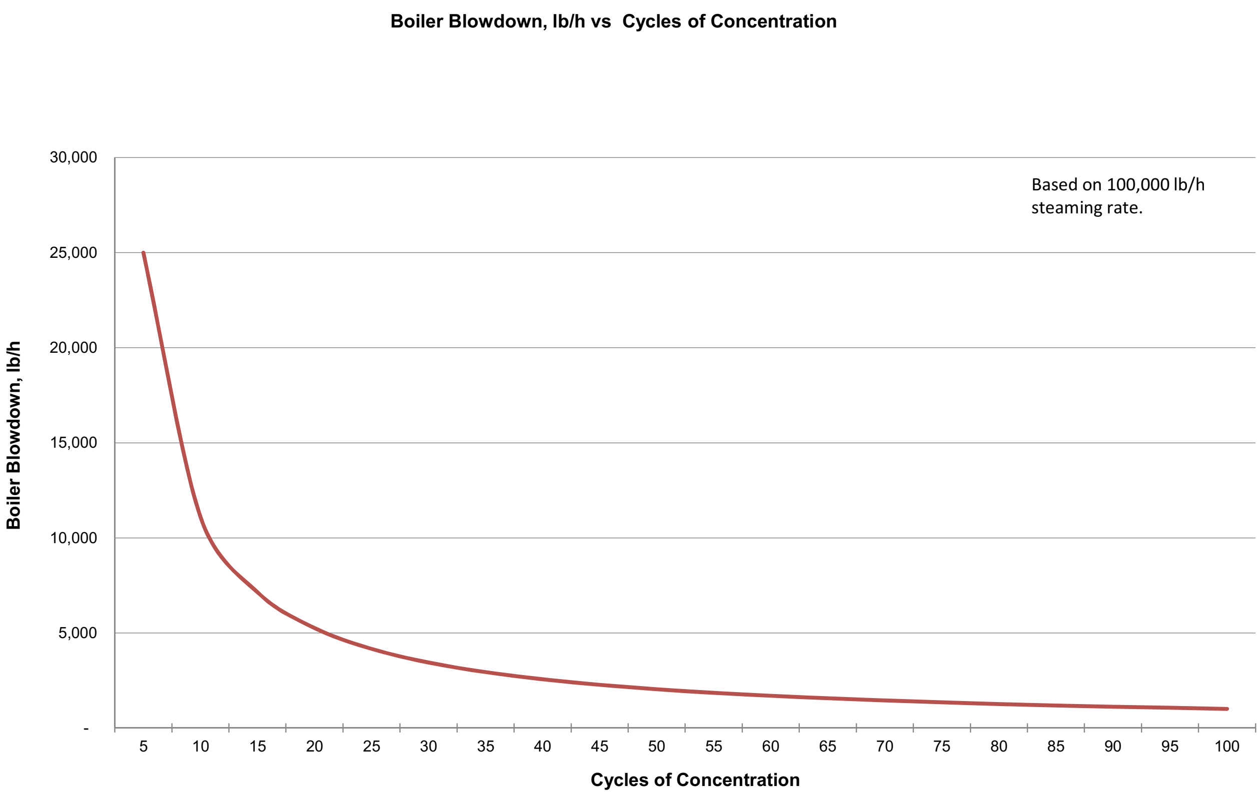


Figure 33—Boiler Blowdown vs Cycles of Concentration

Accurate measurement of BFW ion and boiler water ion concentration is critical to cycle calculations. The measurements of the following components of the BFW and makeup water are used for cycle calculations. Table 27 lists when these are typically used, as well as the effects on the accuracy of each method.

— Flow—Monitoring steam production and blowdown flow allows cycles to be controlled by setting the ratio of steam to blowdown and adjusting blowdown flow. Accurate flow meters and correctly sized blowdown flow control valves are required for this to be successful.

— Conductivity—Boiler water conductivity is frequently used for cycle calculations in softened or reverse osmosis systems where the conductivity of the BFW is stable and only a small percentage of the BFW conductivity comes from volatile components or treatment chemicals. High purity waters can have a significant percent of BFW conductivity coming from volatile components (amine) and treatment chemicals, so cycle calculations should be done based on silica, specific non-precipitating ions, or tracers. Neutralized conductivities are much more accurate for calculating cycles.

— Silica—Silica is often used for routine cycle monitoring and control. This is because silica analyses are relatively easy to perform in the field, and it is significantly more accurate than conductivity for boilers on high purity water. Still, accuracy of silica cycles in high-pressure boilers is impacted by the ability to measure low levels in the BFW, variability of silica in the feedwater, and silica volatility in the high-pressure boiler. Silica variability occurs because of makeup variation, percent condensate return, and leakage in demineralized water systems. In some cases, the feedwater may contain colloidal silica that is not accurately accounted for in the analysis. In the boiler, the colloidal silica reverts to individual silica molecules and show a much higher (apparent) cycles.

— Specific Ions—Certain ions essentially do not precipitate in the boiler water so they are used to confirm field calculations for cycles. The ions most frequently tested are Cl, SO_4, and NO_3 and, in some cases, Na and K. Content in the treatment chemicals has to be taken into account if using Na or K. These specific ions are not typically tested in the field because the testing equipment is expensive and may require certified lab technicians for testing.

— Treatment Product Material Balance—Can be used if the treatment chemicals are fed individually to the boiler and steam rates and product feed rates are known.

— Tracing Agents—Inert tracing can be added to the BFW and measured in the boiler to calculate boiler cycles. Inert tracing agents are not present in the makeup or condensates so they can be added to a specific level with automated feed systems. This provides a fixed ppm level in the BFW and generally tightens blowdown control. If the inert tracer is not on automated feed its concentration will vary with BFW changes.

10.4 Boiler Water Monitoring and Control

10.4.1 General

Table 28 lists the basic testing recommended for monitoring the boiler water chemistry. The boiler water chemistry monitoring and control can be fully automated. Automating boiler water chemistry monitoring and control systems should be discussed with your water treatment expert.

10.4.2 Boiler Water Sampling

Boiler water sampling conditioning systems are shown in Figure 30.

10.4.3 Chemical Feed Location

Oxygen scavenger, amine, and internal treatment chemical feed locations are listed in Table 29. It is important that all water treatment chemistry be fed through an injection quill or internal distributor to prevent damage to the system.

Table 27—Boiler Water Cycle Control and Monitoring Methods

Cycle Control Method	Typically Used For	Parameters Affecting Accuracy	Testing Process	Automated Control
Conductivity	Softened or reverse osmosis water	Changes in makeup quality	Spot test or online	Possible
		Changes in percent condensate return		
		Treatment chemicals		
		Loss of volatile chemistry (Note 1)		
		Hydroxide from carbonates (Note 2)		
Silica	Typically used for high purity water, but also applicable for reverse osmosis water	Changes in makeup quality	Spot test or online	Possible
		Changes in percent condensate return		
		Precipitation, primarily if magnesium is present (Note 2)		
Specific ions (Na, K, Cl, SO_4, NO_3) (Note 4)	Any feedwater type. Caution regarding high purity water, as ions may be below the detection limit.	Changes in makeup quality	Lab testing	No
		Changes in percent condensate return		
		Presence of Na or K in treatment chemicals		
Flow	Any feedwater type	Accuracy of flow indicator	Online steam and blowdown flow indicator	Possible
Tracing agents	Any feedwater type	Accuracy of analysis	Spot test or online	Possible

NOTE 1 Volatile amine chemistry will flash to the steam. In high purity water steam generation systems, percent conductivity loss from volatile amine chemistry is high.

NOTE 2 Carbonate breakdown in the boiler producing hydroxide alkalinity, which has a much higher conductance.

NOTE 3 Silica can precipitate in boiler systems with hardness contamination as magnesium silicate hydroxide.

NOTE 4 Chemical treatments added directly to the boiler will increase the specific ion concentration in the boiler water. This may be an issue when using Na or K ion concentration. This will give an inaccurate cycle calculation, so their contr bution should be subtracted. Some specific ions, such as calcium and magnesium, can precipitate and, therefore, should not be used. Iron and copper will generally deposit in the boiler and should not be used as well.

Table 28—Boiler Water Monitoring

Chemical Test (Note 1)	Monitoring Purpose	Sample Analysis Performed	Frequency
Sample Location: Continuous Blowdown Line Prior to Flash Drum			
pH	Chemical program requirements	Lab (Note 5)	Once/shift
	Corrosion potentials in the boiler		
Conductivity	Diagnostic for cycles	Lab (Note 5)	Once/shift
	Carryover potential		
Internal chemical treatment (Note 2)	Chemical program requirements	Lab (Note 5)	Once/shift
	Corrosion and deposition potentials		
Silica	Steam purity	Lab (Note 5)	Once/shift
	Diagnostics for cycling		
	Deposit potential		
Total and hydroxide alkalinity (Note 3)	Steam purity	Lab	Once/shift for boilers on residual phosphate, chelant, or all polymer programs
	Diagnostics for cycling		
	Deposit potential		
Sulfite (Note 4)	Oxygen scavenger levels	Lab	Once/shift if used as the oxygen scavenger
	Deaeration efficiency		
Inert tracing agents	Diagnostics for cycling	Lab (Note 5)	Once/shift
	Chemical treatment level		

NOTE 1 These are generic tests. Specific test methods should be selected based on detection limits, interferences, etc. The choice of test method(s) should be discussed with your water treatment expert.

NOTE 2 Internal chemical treatments will vary greatly depending on the boiler feedwater quality, boiler operating pressure, and steam requirements. PO_4 for congruent or residual phosphate treatment is monitored in the blowdown. Chelant is monitored in the boiler feedwater. Polymer levels and polymer tracer levels are measured in the boiler feedwater or boiler water, depending on the concentration and ability to measure.

NOTE 3 Hydroxide a kalinity testing should be performed by titration to the phenolphthalein endpoint after carbonate is precipitated with barium chloride.

NOTE 4 Sulfite oxygen scavenger is monitored in the cycled boiler water. Volatile oxygen scavengers are monitored in the boiler feedwater.

NOTE 5 These tests are most frequently done in the lab (grab samples). However, online analyzers are available.

Table 29—Chemical Feed Locations

Boiler Process	Chemistry	Feed Location	Chemical Feed Process	Chemical Feed Quill	Chemical Strength
Deaerator	Oxygen scavenger	Drop leg between deaerating section and storage drum or both ends of the storage drum	Continuous	Standard, 304/316	Neat (undiluted) is preferred (Note 1)
	Neutralizing amine	Drop leg between deaerating section and storage drum	Continuous	Standard, 304/316	Neat (undiluted) is preferred
	Internal treatment (Note 2)	Drop leg between deaerator storage drum and BFW pump	Continuous	Standard, 304/316	Neat (undiluted) is preferred
BFW pump effluent	Internal treatment (Note 2)	After BFW pump prior to economizer	Continuous	Standard, 304/316	Neat (undiluted) is preferred
Boiler steam drum	PO_4 internal treatment (Note 3)	Internal steam drum feed line	Continuous	Mild steel pipe	Diluted to 0.5 % PO_4
Steam header (Note 4)	Neutralizing or filming amine (Note 7)	Primary header	Continuous	Stainless steel atomizing quill (Note 5)	Neat (undiluted) (Note 6)

NOTE 1 Oxygen scavengers react with air so the dilution procedure should minimize deactivation. The dilution tank should not use high-speed mixing devices and should be fitted with a barrier to minimize contact with the air.

NOTE 2 Chelant—Polymer internal treatments should be fed downstream of the economizer or at least downstream of the BFW pump. Residual phosphate or congruent phosphate internal treatments can be fed upstream or downstream of the BFW pump. If the BFW is being used for attemperation, the internal treatment shall be fed after the BFW attemperation takeoff.

NOTE 3 All phosphate treatments applied directly to the steam drum should be diluted. The phosphate active level should be 0.5 wt % or less. This dilution is done to ensure that the phosphate will not precipitate in the boiler drum internal feed distribution line. Straight chelants, polymers, and caustic chemistry should not be applied directly to the steam drum.

NOTE 4 Amine addition to the steam header is infrequent; however, with high a kalinity feedwater it may be necessary to add neutralizing or filming amines to steam headers. This may be the main steam header, upstream of a reboiler, or downstream of a flash tank.

NOTE 5 Amine application to the steam requires an atomizing quill. This quill should be a minimum of 10 pipe diameters prior to a bend or elbow.

NOTE 6 Amine dilution should be minimal to prevent liquid water droplets when applied to saturated steam.

NOTE 7 Filming amines can cause fouling; your water treatment expert should be consulted prior to use.

11 Steam Purity

11.1 Considerations

Steam purity is the measurement of solids in the steam. Acceptable steam purity is needed to prevent deposits in superheaters and steam turbines, prevent steam line cracking, and minimize condensate system corrosion. Some processes may also be impacted by steam purity. ASME and turbine manufacturers provide guidelines for steam purity, which is achieved by controlling boiler water quality and achieving good steam/water separation in the steam drum.

11.2 Steam/Water Separation

In modern industrial boilers the goal of steam separation is to remove or reduce the solids contamination of the steam, known as carryover, before being used in plant processes or steam turbines. The steam drum provides the space for saturated steam to separate from the steam/water mixture discharged by the boiler tubes. The drum shall also provide space for additional steam separation, feedwater introduction, chemical treatment introduction, and water level fluctuations caused by variance in steam load. Increased boiler operating pressure has a negative effect on the tendency of steam and water to separate by gravity.

Therefore, mechanical methods of separation become necessary. Primary steam separation occurs by gravity behind some type of baffle arrangement in the steam drum. Baffling can be vertical, inclined, V-type, or dual compartment, all designed to break up steam and water jets coming from riser tubes and to ensure that no steam is recirculated back to the heating tubes.

A more sophisticated means of primary separation is the cyclone steam separator. Here, the steam/water mixture enters tangentially and water forms on the cylinder walls and the steam moves to the center and upward passing through a corrugated scrubber at the top of the cyclone.

If operating conditions dictate due to large fluctuations in steam load or feedwater quality, then secondary separation is necessary. These separators are typically large, corrugated-plate scrubbers where steam passes slowly between closely fitted plates to ensure maximum contact and thereby, avoids re-entrainment of the separated boiler water. The separated water is subsequently collected and returned to the drum water.

Steam washing with BFW or steam condensate is occasionally employed to reduce steam solids content. This technique does not reduce moisture content, but does remove silica if this contaminant is of primary concern.

Silica laden steam is washed by a condensing type steam washer, in which steam is condensed on finned tubes by feedwater and the steam is washed by its own condensate and silica is absorbed (removed) from the steam.

Normally, steam purity is referred to as the measurement of solids carryover in the steam and should not be confused with steam quality. Boiler design, boiler pressure and steam users, dictate the steam purity requirements. In most industrial boilers operating in the 4150 kPa (ga) to 10,350 kPa (ga) [600 psi (ga) to 1500 psi (ga)] range, steam purity should be 0.1 ppm solids or less to minimize deposition issues with superheaters, process use, or turbines. Boiler manufacturers normally do not guarantee steam purity below 1.0 ppm, but performance shows that 0.1 ppm can be achieved. In refinery applications where avoidance of turbine water washing is desired, even lower steam solids should be maintained, 30 ppb solids (10 ppb sodium) or less and certainly no more than 60 ppb solids (20 ppb sodium). The 0.1 ppm or 100 ppb solids (30 ppb sodium) are acceptable for most superheaters. The standard recommendation for steam silica to a superheated steam turbine is <20 ppb SiO_2. ASME recommends similar steam purity for boilers with superheaters and turbine drives.

11.3 Attemperation—Surface or Direct Contact

There are two types of heat removal devices used in industrial boilers, the surface type where steam temperature is regulated by indirectly removing heat from the superheated steam or directly by diluting high temperature steam with lower temperature water.

When a surface type attemperator is used, part of the superheated steam is diverted into a shell or drum and is reduced in temperature by exchanging its heat to the boiler water indirectly and then re-mixes with the rest of the steam from the superheater to control the steam mixture temperature.

The more commonplace method of controlling steam temperature is the direct contact or spray-type attemperator. The highest purity available of water is introduced through a spray nozzle at a venturi section of line, causing the water to vaporize and mix, thereby cooling the superheated steam. It is critical that the spray water be of highest purity, typically from a sweetwater condenser, since contaminated solids could enter the steam and cause downstream deposition problems. Attemperation water may be from a sweetwater condenser, polished condensate, unpolished condensate, or high purity BFW with only volatile treatment chemicals. ASME recommends attemperation water meet the quality listed in Table 30.

Table 30—Attemperation Water Quality

Contaminant	Level
TDS	<30 ppb
Na	<10 ppb
SiO_2	<20 ppb
O_2	Essentially O_2 free

11.4 Monitoring and Control and Sampling

Steam separation efficiency is a measure of the amount of moisture in the steam and is referred to as steam quality. It is the weight of dry steam in a mixture of steam and water droplets. The liquid is of concern as it contains dissolved solids, which can contaminate the steam. Also, the water itself can be harmful to downstream equipment such as superheaters and steam turbines. This, however, is not the only mechanism by which contaminants can enter the steam. Carryover refers to any contaminant that leaves the boiler drum and can be in the form of a solid, liquid, or vapor. The most common type of carryover is mechanical carryover where boiler water is entrained in the steam, resulting in dissolved and suspended solids entering the steam. Another common type of carryover is chemical carryover resulting from foaming or selective vaporous carryover of solids, specifically silica. Problems associated with contaminated steam include:

a) superheater overheating via deposition, corrosion, and increased failure potential;

b) steam line and expansion joint failure;

c) turbine issues like control valve sticking, turbine blade deposits and erosion, and turbine disk cracking;

d) process product contamination or catalyst contamination.

Regardless of the method of steam purity measurement, proper sampling with properly designed nozzles is essential for testing accuracy. ASTM identifies the proper techniques in ASTM D1066. The procedure details specifications for establishing isokinetic flow through properly designed nozzles across equal cross-sectional areas of a saturated steam line sample point. It is extremely difficult to test steam purity of a superheated steam sample. The reason is because sodium salts are highly soluble in superheated steam and become more insoluble at saturation temperature. Therefore, if the reduction to saturation temperature is gradual, the salts will deposit on sampling lines and produce erroneous results. Superheated steam shall be desuperheated at the sampling point to improve accuracy.

ASTM D1066-06 specifies only a single port nozzle, which should ideally be installed at least 35 internal pipe diameters downstream and 4 internal pipe diameters upstream of a flow disturbance. Since this length of pipe is often not available in industrial systems, a multiport nozzle is a good alternative. A multiport nozzle is shown in a previous edition of ASTM D1066, issued in 1997 (ASTM D1066-97) and reapproved in 2001.

The question arises as how to best to measure steam purity. Online analytical methods provide the best assurance of steam purity. The most widely used method is specific conductance (conductivity), which is the measure of electrical current through a test sample. The conductivity, measured in micro S/cm, is proportional to the concentration of the ions in the sample. If boiler water carries over into the steam, the dissolved solids content of the steam increases and therefore, the conductivity does too. The accuracy of the conductivity measurement is its drawback, specifically due to the potential for dissolved gases in the sample. Therefore, degassing and hydrogen ion exchange media shall be utilized to reduce NH_3 and amines, and then subsequent reboiling shall be done to remove carbon dioxide. This increases the accuracy of steam specific conductance measurement. The technique is described in ASTM D4519-94. There are two other potential issues with using cation conductivity:

a) organic chemicals in the boiler treatment may not be removed and will, therefore, contribute to cation conductivity; and

b) NaOH carryover would be undetected by this method.

Therefore, the most accurate method is online measurement of sodium ion concentration, which can be prorated based on boiler water chemistry to determine carryover.

The most commonly used online method is the sodium ion analyzer. This instrument uses a selective ion electrode to directly measure the sodium content of steam down to as low as 1 ppb.

There are two additional analytical methods, ion chromatography and inductively coupled plasma for determining ultralow levels of ion concentrations for offline spot sampling or to verify the online determinations.

Proper measurement and sampling of steam purity does not tell the entire story. Monitoring and detection of carryover issues that could adversely affect steam purity is critical for efficient operation. Effective monitoring starts in the operations control room and centers on analyzing changes in operating conditions such as the following.

— System Chemistry—a review of chemistry and changes in feedwater or boiler water chemistry, increased conductivity, or changes in online analyzers like sodium can lead to steam contamination.

— Superheated Steam Temperature Changes—Sudden temperature drops are normally indicators of water being carried into the superheater, resulting in more heat needed to evaporate the water and causing a decrease in temperature. Prolonged foaming, priming, or mechanical separator issues can cause a longer, more gradual decline in superheated steam temperature.

— High or Fluctuating Drum Level—High steam drum water level or rapid change in steam load can lead to carryover problems and negatively impact steam purity.

— Header Pressure Variations—Variable steam header pressures cause high and fluctuating drum levels, which can lead to serious carryover problems.

— Efficiency Loss—Lower superheater outlet temperature, decrease in spray water usage, or increased fuel consumption all are indicators of superheater deposition and a subsequent loss of efficiency, as more heat is required to evaporate the carryover moisture.

— Increased Superheater Tube Temperatures—If deposits form on superheater tubes, then an increase in metal temperature, as measured by thermocouples on superheater circuits, occurs and a loss of efficiency or failure can result.

An increase in the turbine stage pressures can signal fouling. This is determined by monitoring stage pressures vs steam flow under similar conditions.

— Loss in Turbine Generator or Compressor Capacity—As turbine fouling occurs, the maximum output from the steam driven machine is reduced.

— Sticking Steam Valves and Regulators—Deposit build-up on admission or stop valves and regulators can cause malfunctions and are a good sign of steam contamination or purity issues.

12 Boiler Piping

12.1 Interconnecting Piping

12.1.1 Purpose

Interconnecting piping joins the boiler to feedwater and steam supply systems and provides a means to control, isolate, and drain the system.

12.1.2 General Description

Piping external to the boiler may be used to connect parts of the boiler to the rest of the system or to other parts of the boiler. This may include the feedwater supply, the economizer (if used), steam and water drums, superheaters, reheaters, desuperheaters, convection tube banks, furnace tube banks, bypasses, blowoff and blowdown lines, vents, and drains. This piping also includes flanges, valves, instrumentation, and control devices necessary for proper system start-up, operation, and maintenance.

12.1.3 Mechanical Details

• Industrial fired boilers are typically designed to the ASME *BPVC*. An ASME accredited authorized inspector (AI) reviews, inspects, and approves all boiler and boiler piping installations and has the final decision on code acceptance. References within this document refer to ASME *Code* as the Code of Record. Local authorities may amend or supplement portions of the ASME *BPVC* to meet local and/or regulations outside of the United States or Canada. The Code of Record, if other than ASME *BPVC*, shall be clearly defined by the purchaser.

Tubes and piping that comprise the main steam generating circuit within the boiler and related auxiliaries that are exposed to hot furnace gases (steam generating tubes and tubes within auxiliary equipment used in feedwater heating or for steam generation, as described in Section 5 of this document, otherwise known as the “boiler proper”) are within the jurisdictional limits of Section I of the ASME *BPVC*. Piping external to the boiler may be constructed to different codes depending on where the piping is in the system and the type of installation. All piping that is not part of the boiler proper is considered boiler external piping or nonboiler external piping.

The jurisdictional limit of a boiler external piping system is defined by Section I of the ASME *BPVC*. Boiler external piping is designed, fabricated, installed, and tested to ASME B31.1.

Nonboiler external piping may be designed, fabricated, installed, and tested to ASME B31.1 or ASME B31.3 depending on the facility in which the system is being installed. Utilities typically design nonboiler external piping to ASME B31.1 and process plants typically design to ASME B31.3.

• The transition from ASME *BPVC* Section I and ASME B31.1 piping boundaries to ASME B31.1 or ASME B31.3 for nonboiler external piping shall be specified by the purchaser.

ASME B31.1 and ASME B31.3 define acceptable tube and piping materials used for piping systems, pressure and temperature limits, and allowable stress values for each material to determine minimum wall thickness of piping. Generally carbon steel tube and piping are utilized for low to medium pressure/temperature applications. Carbon steel piping may experience graphitization at elevated temperatures [around 427 °C (800 °F)] and is often limited to applications with a design temperature of 399 °C (750 °F) or less for this reason. Above 399 °C (750 °F) low alloy (chromium-molybdenum) steels are typically used.

- The boiler manufacturer shall decide the design temperature margin to apply to the maximum piping metal temperature. A typical temperature margin is 15 °C (25 °F).

  ASME *BPVC* permits the use of seamless and ERW tubing and piping. The purchaser shall specify the acceptability of ERW for tubing and piping.

- The purchaser shall specify a corrosion allowance to apply to the wall thickness for headers and piping external to the boiler.

  Headers external to the boiler that are part of the steam generating circuit shall be designed to provide even flow distribution to all flow passes.

- The purchaser shall specify the type of piping terminal connections (welded or flanged). All flanges shall be weld-neck flanges.

  Piping systems shall be sized in accordance with accepted industry practices to avoid velocities that may contribute to excessive vibration, erosion, and pressure drop.

  Provisions for thermal expansion of piping shall take into consideration all specified operating conditions.

- The purchaser shall specify if low-point drains and high-point vents are required.

12.1.4 Operation

Piping systems external to the boiler contain the valves, control devices, and auxiliary systems needed for safe and reliable operation of the steam system.

Consideration should be given to the design pressure of piping systems upstream of the feedwater stop valve based on feedwater pump maximum (shutoff) pressure.

NRVs installed in steam supply piping shall be stable throughout the boiler's entire operating range.

12.1.5 Maintenance

Piping systems shall be arranged such that all valves are accessible from grade or from platforms.

Manifolds and external piping shall be located so as not to block access to inspection openings or prevent removal of auxiliary equipment.

Spectacle blind flanges should be considered to permit isolation of major boiler components during installation, cleaning, testing, and maintenance.

Piping systems should be inspected annually as a minimum by a technically qualified inspector. API 570 and API 574 describe and specify in-service inspection practices and condition-monitoring programs for piping system components.

12.1.6 Troubleshooting

Boiler performance and efficiency can be impacted by many things, including improper operation of or poorly maintained auxiliary piping system components. Water/steam chemistry, steam temperature and pressure, and boiler efficiency may suffer if these components do not function properly or if steam leaks develop in the piping system.

12.2 Downcomers

12.2.1 Purpose

The purpose of downcomers is to provide a flow path for cooler water to travel from the steam drum to the lower (mud) drum. The downcomers, along with the steam generating tubes discussed in 5.2, comprise the boiler's natural internal circulation path.

12.2.2 General Description

Natural circulation within a boiler is created by the density difference created between the steam/water mixture in the hotter (lower density) steam generating tubes and the cooler (higher density) water in the downcomers. The downcomers provide the water supply to the lower (mud) drum, which connects to the steam generating tubes.

12.2.3 Mechanical Details

Downcomers may be located inside (internal to) or outside (external to) the boiler. Downcomers are part of the boiler proper and fall within the jurisdictional limits of ASME *BPVC* Section I. Internal downcomers are often constructed using boiler tubing, whereas external downcomers are typically rigid piping.

Internal downcomers are located in the boiler's convection section and are exposed to furnace gases. Internal downcomers are sometimes considered to be steam generating tubes (heated) for this reason, although no vaporization takes place as in the steam generating tubes.

External downcomers are unheated, and are common with elevated steam drum boiler designs.

Refer to 5.2 for mechanical details.

12.2.4 Operation

Sizing of downcomers is critical to ensure that enough water is provided to the steam generating tubes so that natural circulation will occur within the boiler.

- The purchaser shall specify if circulation calculations, complete with design criteria and a diagram for each circuit, are required. The purchaser shall state the required condition(s) (% MCR) corresponding to the calculations.

12.2.5 Maintenance

See 5.2 and 12.1 for inspection and maintenance of downcomer piping and tubing.

12.2.6 Troubleshooting

Internal downcomers, along with steam generating tubes, may also be subject to external fouling from ash or soot buildup if combustion is not properly controlled.

12.3 Vents and Drains

Vents and drains on a boiler system generally fall into two categories; those that are used during boiler operation and those that are used primarily during the filling and draining of the boiler.

a) Vents and drains for filling and draining the unit include high point vents and low point drains. These shall be furnished in sufficient size and quantity to fully drain all sections of the boiler system in a reasonable period of time (generally considered to be 2 h to 3 h). The vents and drains shall also permit the complete filling of the boiler components for hydrostatic testing of the equipment prior to being placed in service initially and after repairs.

Drains shall be capable of draining all sections of the boiler and piping to prevent freeze damage and the accumulation of water side sediment. To ensure complete draining, the drain connections should be flush with the interior surface of the header, pipe, or drum being drained.

b) Vents and drains for use during operation include start-up vents, electromatic relief valves, and superheater condensate drains.

c) Start-up vents may be used to maintain cooling steam flow through superheat tubes, promote natural circulation within the boiler during start-up, and dissipate heat to control the boiler warm-up rate. Start-up vents are typically sized for 10 % to 20 % of the MCR of the boiler on units with superheaters. Mufflers are usually required on start-up vents to control noise to acceptable levels. Saturated boilers with at least 8:1 burner turndown usually do not require special venting capabilities in excess of the normal high point vent from the steam drum. Start-up vents should not be used during normal boiler operation, unless specifically designed to handle the normal operating superheater outlet temperature.

d) Electromatic relief valves may be used to discharge steam to atmosphere during any load. These vents are typically used to prevent the boiler safety valve from lifting in situations where the steam consumer can stop receiving steam abruptly. These valves are used to protect boiler or superheater safety valves from lifting, which might result in a maintenance outage if the safety valves do not properly reseat themselves. Mufflers are usually required on electromatic relief valves to control noise to acceptable levels.

e) Start-up drains are located in superheater headers to remove accumulated condensate from the component low points. These drains are typically used up to approximately 175 kPa (ga) [25 psi (ga)] to ensure all superheater elements are clear of condensate that may have accumulated while boiler was shut down. Care should be exercised not to vent excessive steam from the superheater inlet header, which may result in overheating damage to the superheater tubes.

12.4 Blowdown

12.4.1 General

Blowdown systems have both continuous and intermittent connections on the boiler.

12.4.2 Continuous Blowdown

Continuous blowdown is used to control the concentration of drum water solids by removing from the drum a flow of concentrated boiler water. The continuous blowdown line is located in the steam drum at a location below the normal operating water level and in an area expected to contain the highest drum water contaminant concentrations. A shutoff valve followed by a metering valve is installed on the discharge piping. Continuous blowdown is typically piped to a blowdown flash tank so that any steam can safely flash to atmosphere and the remaining water can be cooled sufficiently to be discharged to the waste water system. Continuous blowdown flows typically range from 1 % to 5 % of the feedwater flow.

A blowdown control valve in conjunction with a conductivity meter is sometimes used to provide automatic control of the blowdown flow during changes in boiler operating load.

12.4.3 Intermittent Blowdown

Intermittent blowdown is connected to the lowest practical water space and is used to remove all solids that have precipitated out of the boiler water. It may also be used to lower the steam drum water level under specific operating conditions. It is common for the intermittent blowdown to have an inverted angle slotted at intervals located along the bottom of the mud drum in order to help remove sediment from the full length of the unit. A tight shutoff and a throttling valve are required to ensure reliable operation of the intermittent blowdown system. Intermittent blowdown shall be used carefully to prevent the boiler's natural circulation from being disturbed, which could result in boiler tube failure.

(The use of quick opening and closing valves is recommended to control blowdown discharge.) Typically, intermittent blowdown is only allowed at minimum fire or when the burner is shut off. Intermittent blowdown is typically piped to a blowdown flash tank so that any steam can safely flash to atmosphere and the remaining water can be cooled sufficiently to be discharged into the waste water system.

NOTE Blowdown flash tanks are typically only sized to accept a water flow equal to 100 mm (4 in.) of water level drop in the steam drum.

Care shall be exercised to ensure the blowdown tank does not overfill during intermittent bottom blows. The line diameter of the intermittent blowdown (also called “blowoff”) shall not exceed 63 mm (2.5 in.), according to ASME *BPVC*. The maximum water flow to the flash tank is limited by that line diameter and the maximum allowable water velocity in the blowdown line.

13 Boiler Trim and Instruments

13.1 Water Column and Gauge Glasses

13.1.1 Purpose of Monitoring and Controlling Steam Drum Water Level

The measurement and control of steam drum water level is vital to the safe and reliable operation of the boiler itself and to ensure the safe and reliable operation of equipment downstream of the boilers.

If the drum water level is too high, the steam separation devices will not function properly and water droplets will carry over into the steam superheating sections. Since the water droplets contain a high degree of total suspended and solids, the latter can deposit on the superheater tubes; consequently, the tube metal can overheat and possibly fail since the internal tube scale formed by the deposits has low conductivity. The water droplets/deposits can also be carried out of the boiler’s superheater outlet to the plant piping/valves, and to other equipment, such as steam turbines and heat exchangers, causing further damage, degradation of performance, and increased maintenance.

There are even more severe consequences if the drum water level is too low. Too low of a water level will result in a lower static water level, which will result in lower steam-water circuit recirculation, which in turn will cause overheating of evaporator tubes. Moreover, an extremely low water level will, if undetected, deplete the entrances of downcomers/ tubes of water, causing them to run dry. Tubes exposed to the furnace gases will then fail due to high metal temperature.

The requirements of ASME *BPVC* Section I should be considered as a minimum requirement for water column instrumentation and gauge glasses. Moreover, some U.S. states enact further requirements to augment those of ASME as law, and underwriters can also stipulate further requirements of their own. See Section 2 for applicable ASME references.

Therefore, it is of the utmost importance that the water column instrumentation and gauge glasses be specified considering all of the above as to not only provide the input to the feedwater controls but also to provide the necessary alarms and trip points to the BPCS and safety interlocks and to provide a true indication of water level for the operators, both locally and in the control room.

The instrumentation shall also be specified and designed considering the dynamics of changing demands on boiler load or flow and drum pressure and the effects on the design and configuration of the instrumentation.

Some of the causes and effects that occur in the steam drum, which the engineer shall take into account in terms of the design of the configuration and for instrumentation are those listed below.

Boiling water is a mixture of steam and water and as the firing rate increases or when the pressure of the steam is decreasing, the quantity of steam bubbles increases within the steam/water circuit and the steam drum. This causes a decrease in density and an increase volume of the steam and water mixture within the drum, a phenomenon known as “swell.” While the level of the drum water appears to rise, this is not a true indication of the actual liquid water quantity within the boiler system.

When the firing rate has decreased, or when the steam pressure is increasing, the quantity of steam bubbles decrease within the steam/water circuit and in the steam drum. This increases density and decreases volume of the steam and water within the drum—a phenomenon known as “shrinkage.” While the level of the water appears to be lowered, this is not a true indication of the level of the actual liquid water quantity within the boiler system.

If only the water level is used to control the rate at which the water is admitted to the boiler, the effects of swell and shrinkage will cause the opposite effect of what is required, i.e. reducing feedwater flow rate on an increase in firing rate and increasing the feedwater flow rate on a decrease of firing rate. Therefore, to counter the effects of swell and shrinkage, a two-element control system shall be used, one element being the drum level and the other being steam flow (refer to Figure 19).

However, two-element feedwater control also has a disadvantage, as the feedwater flow rate will vary non-linearly as a function of the pressure drop across the feedwater control valve and the valve’s opening (flow area). In a boiler with a steam drum, the feedwater flow may not always be equal to the steam flow, particularly in a transient condition where there is a sudden load change imposed on the boiler and the feedwater controls cannot react quickly enough to the change. To offset this problem, the parameter of feedwater flow is brought in to the control scheme to restore the balance of feedwater and steam flow. This control is referred to as three-element feedwater control and incorporates the measurement of feedwater flow, steam flow, and drum level. Refer to Figure 20.

This standard recommends that a three-element feedwater control with a cascaded feedwater control loop be used.

NOTE The three-element control should be designed so that the operator can revert to single-element control (drum-level only) during start-up or at loads beneath 20 %, as steam and feedwater flow transmitters are usually the most accurate at higher flow rates.

13.1.2 Monitoring and Indicating the Drum Level

From the discussion above, the first element is the accurate measurement of the steam drum water level. There are several methods and each is worthy of further discussion as each has its own characteristics that in themselves require special design considerations.

a) Differential pressure transmitter with constant head reservoir, without a water column.

   In this control scheme, a differential pressure transmitter mounted outside and beneath the steam drum. The theory is that the pressure differential of the height of the water L inside of the drum will be indicative of the water level inside of the drum. A constant head reservoir is provided in the pipe connected to the steam space and is deliberately left uninsulated to allow steam to condense and keep the pipe to the transmitter full of water. The actual pressure differential is a function of several variables:

   1) the static pressure of the water level in the drum,

   2) the densities of the water and steam above the transmitter,

   3) the densities of the water in the pipes leading to the transmitter.

   The differential pressure at the transmitter ports is defined by the following equation:

$$\mathrm{DP} = (1/\rho_r) \times \{(H \times \rho_c) - [(L \times \rho_w) + (H - L) \times \rho_s]\}$$

where

- DP is the differential pressure at the transmitter at 20 °C (68 °F);
- H is the distance between the bottom and top connections at the steam drum;
- L is the height of the water in the drum above the bottom connection on the drum;
- ρ_c is the density of the condensate in the sensing line at operating temperature;
- ρ_r is the density of water used for calibrating the transmitter at 20 °C (68 °F);
- ρ_s is the density of water in the drum at operating pressure;
- ρ_w is the density of the steam in the drum at operating pressure.

Since the densities of the steam and water in the drum are a function of the conditions within the drum, pressure and temperature are transmitted to the BPCS. An algorithm, based on the above equation, is developed for use within the BPCS to provide a true indication of the drum's water level.

NOTE The differential pressure at the transmitter and signal (4 ma to 20 ma) will be the highest when the separation between the water level and the top connection at the drum (lowest drum water level); therefore, the signal shall be reversed in the BPCS.

Contingency plans or other methods for drum level indication shall be considered in case the BPCS fails.

b) Drum level measurement with an external water column.

The method used in Item a) may give an erroneous reading if the drum pressure falls off rapidly and the condensate in the reservoir and leg flash evaporates because the saturation temperature was reduced. To offset this problem, an external water column is connected to the drum that has sufficient volume so that the level of water in the column is theoretically the same as within the drum.

The level transmitter is connected to the water column instead of being piped to the drum. Other features to be noted include the following.

1) The interconnecting pipework between the drum and the column is of sufficient size and arranged so that the fluid can flow through the water column itself.

2) The upper leg piping is sloped downward from the connection on the drum to the column; the lower leg piping is sloped downward from the column to the lower connection on the drum.

3) Unlike the drum and other pipework, the water column and the upper section of pipe are left un-insulated so that the steam condenses and the impulse line leading to the level transmitter remains full of condensate.

4) The flow of fluid is established through the water column, with the steam actually leaving the drum at the upper steam drum connection, condensing in the pipe and water column, and returning to the lower drum connection. The circulating flow tends to maintain the temperature of the water within the column closer to that which is within the drum minimizing the error caused by a difference in water density.

c) Other technologies for indication of drum level.

The water within the steam drum contains anions and cations; the conductivity of the water can be utilized to determine the water level in the drum at discrete levels with a sufficient number of electrodes in the water column, described in Item b). The same technology can be used for alarm/trip signals.

13.1.3 Design Requirements

Design requirements for water column instrumentation and gauge glasses include the following.

a) As a minimum, all statutory requirements shall be met for the country and state or province in which the boiler(s) will be sited.

b) In the United States ASME *BPVC* Section I has mandatory requirements as noted below; further requirements of this standard are noted in (italics):

1) Materials for the boilers and boiler external piping/valves, including those for the steam and water piping for water columns, are subject to the requirements of Section PG-5. The requirements of PG-5.5 and Footnote 1 state that the use of austenitic alloy steels for boiler pressure parts that are steam touched in normal operation are allowed; however, the use of austenitic alloy steels for boiler pressure parts that are water wetted in normal service is prohibited, unless the provisions of paragraphs PG-9.1.1, PG-12, and PEB 5.3 are met.

i) Paragraph PEB 5.3 (for electric boilers) allows for 304L, 316, 316L, and 347 alloy steel with the proviso that only deionized water shall be used in the boiler. *Since this is an unreasonable expectation for boilers under this standard, these alloys shall not be used for the boilers' wetted parts including those of the water columns, piping valves or trim.*

ii) Paragraph PG-9.1.1 lists materials for once through boilers, but these types of boilers are beyond the scope of this Standard.

iii) Paragraph PG-9.1.2 lists material specifications that are permissible for connector piping and tubing and the pressure chambers for remote water level sensing devices as referenced by PG-12.2. One of many material specifications is ASME SA312, *Seamless and Welded Austenitic Stainless Steel Pipe*.

iv) PG-12, Water Level Indicators and Connector Material, provides further guidance and requirements for materials. PG-12.1 states that gauge glass bodies and connector bodies may utilize austenitic stainless steels and nickel-based alloys.

v) PG-12.2 provides for materials for alternative sensing devices or methods for boilers having a MAWP not exceeding 6 MPa (900 psi). Alternative devices include a magnetically coupled float inside a non-magnetic cylindrical pressure vessel. These devices are acceptable, provided the chamber stresses and dimensions meet the appropriate requirements of PG-27 and Part PW, comply with one of the requirements (for materials) under PG-9.1.2, but be restricted to only the material grades listed in PG-12.3.

PG-12.3 states that connector and pressure chamber materials may include austenitic stainless steels and nickel-based alloys, but with the provisos that the materials be solution annealed and filler metals for welding austenitic stainless steel are limited to low-carbon content.

NOTE Water columns are specifically excluded in PG-12.3.

1) To ensure the material requirements of the *Codes* will be met, the purchaser will provide the projected steam water analyses to the supplier. The supplier will provide detail drawings and a bill of materials for the purchaser for review.

vi) Paragraph PG-60, Sections 60.1 through 60.4 cover the general boiler requirements for the number, design and the materials for water level indicators, water columns, valves, and connections. Refer to Figure PG-60 for requirements with respect to the visible portions of the gauge glass. The locations of connections A and B shall be as determined to at least cover the lowest safe operating level in the drum and the highest point possible on the steam drum.

1) For this purpose, the boiler supplier shall provide a dimensioned cross-sectional drawing of the steam drum showing the internal steam drum diameter, elevations of entrances and exits of tube down-comers, blowdown piping, entrances/exits of steam separation devices, normal operating level, LWL, lowest safe operating level, high water level for alarm, and high-high water level trip. The locations of the drum connections, steam and water piping, layout of the water column, gauge glasses, water columns, level switches, and transmitters shall be superimposed on this drawing.

vii) Paragraph PG-60.1.1.4 provides for restrictions for remote level indicators. Also refer to PG12.2.

viii) Figure PG-58.3.1 illustrates *Code* jurisdictional limits for drum-type boilers and includes the code beaks for the steam drums control device water column, piping, and associated valves. The administrative, jurisdictional, and technical authority dictate that the piping to and from the water column, the column itself, and the piping/valves to and from the instruments/gauges to be boiler external piping and joints and are, therefore, subject to *Code* stamping, ASME forms, etc., as required within ASME *BPVC* Section I.

13.1.4 Other Requirements

Other requirements of this standard include the following.

a) Each steam boiler drum shall be provided with two independent means (separate systems) of providing the boiler operator with an accurate indication of the boiler water level in the drum.

b) The pipe and valve sizes for water and steam shall be no less 25 mm (1 in.) NPS. The use of threaded connections shall be minimized.

c) The water level gauge in which the water level can be observed shall be mounted so that the lowest water level that can be observed is at least 50 mm (2 in.) above the lowest water level at which there will be no danger of overheating any part of the boiler, when operating at that level.

13.2 Safety Valves

13.2.1 General

Safety valves shall be specified in accordance with the *Code of Construction* for the boiler. This section is based on compliance with ASME *BPVC* Section I. Refer to the *Code* for items not covered below.

Safety valves are designed to relieve in the event of a blocked steam outlet. Protection is normally provided on the generator steam drum and the superheater coil outlet. Boilers of any substantial size [e.g. over 1800 kg/h (4000 lb/h)] shall have at least two safety valves. Every attached superheater shall have a safety valve near the outlet. If there are no intervening valves between boiler and superheater, the valve on the superheater outlet may be included in determining the number and size of the boiler safety valves. This requirement results in a minimum of two safety valves protecting the steam generating system.

It is recommended that (at least) two valves be located on the drum and one valve on the superheater near its outlet. The two drum valves shall have a combined capacity equal to at least 75 % of the maximum generating capacity. The superheater outlet safety valve should be sized for the remaining relief requirement, but shall not be sized for less than 20 % of the total capacity.

However, it is often desirable to size the superheater valve larger to limit the steam temperature during relief. Higher than normal steam temperatures will occur at the superheater outlet during relief because flow is reduced from rated down to the capacity of the safety valve. In high temperature systems, care shall be taken to avoid exceeding the valve's temperature rating during relief.

13.2.2 Steam Generator

Set one valve on the boiler drum at (or below) the drum MAWP. Generally, set the additional drum valve(s) up to 3 % above the MAWP.

NOTE The complete range of set pressures for saturated steam safety valves shall be within 10 % of the highest valve set pressure. This restriction becomes governing only if the lowest set pressure is considerably below the drum MAWP, which is not commonly done.

ASME *BPVC* Section I states that the minimum required relieving capacity of the pressure-relief valves for all types of boilers shall be not less than the maximum designed steaming capacity at the MAWP of the boiler, as determined by the manufacturer. Since the final generating capacity of the boiler may not be known until after the fabrication-procurement phase is well underway, it may be useful to establish safety valve and drum nozzle sizes early by adding a design margin to the required generating capacity in order to estimate the minimum relieving capacity. Margins of 50 % have been used successfully. The safety valve specification should be based on the manufacturer's capacity.

For the typical situation in which one drum valve is set at the MAWP, and the second is set 3 % higher, the pressure shall not rise more than 6 % above the MAWP. Thus, a 6 % accumulation over the MAWP should be used for calculating required orifice area.

13.2.3 Superheater

Set the superheater safety valve design temperature equal to the relief temperature. As was mentioned earlier, the temperature during relief for superheater valves may be far above the normal temperature because the steam flow through the superheater is reduced from rated flow down to the capacity of the safety valve.

The superheater outlet safety valve(s) should be set to open before the valves on the drum. This practice ensures a flow of cooling steam through the superheater. While in some rare cases the superheater metallurgy is specified based on no cooling steam flow, loss of flow is always a condition better avoided. Therefore, set the superheater valve set pressure lower than the lowest drum valve set pressure by an amount somewhat greater than the pressure drop through the superheater at rated flow. The superheater valve set pressure should also be determined to ensure a sufficient differential between operating and set pressures at each safety valve location.

For medium-pressure steam generators and high-pressure steam generators where normal superheated steam temperature is 370 °C (700 °F), or lower, the relief rate for the superheater safety valve is sometimes set high enough to achieve a relief temperature within the limit for carbon steel safety valves [typically 400 °C (750 °F)]. There is no particular incentive to specify a higher alloy valve. A conservative and simple way to calculate the required steam flow for a given superheater outlet temperature is to assume a constant superheater duty and determine the flow rate that will absorb that duty without exceeding the desired temperature.

For high-pressure steam generators where normal superheated steam temperature is greater than 370 °C (700 °F), set the relief rate high enough to limit the relief temperature to the temperature limit for alloy steel safety valves [typically 540 °C to 590 °C (1000 °F to 1100 °F), depending on the valve model].

At a design temperature of 540 °C (1000 °F), however, the strength of even an alloy steel valve is substantially reduced. Most high-pressure steam superheaters would require a safety valve with higher inlet and outlet flange ratings {e.g. Class 1500 inlet and Class 300 outlet for a 4150 kPa (ga) [600 psi (ga)] steam system}. To avoid the need for such robust flanges, reduce the relief temperature by increasing the steam flow rate to be relieved (subject to the 75 % minimum rate for the drum safety valves). The resulting larger orifice size for the superheater safety valve is preferable to the higher flange ratings. However, the use of multiple superheater safety valves is not recommended because the need for staggering the set pressures could require the design pressure of the boiler to be raised in order to prevent the no-flow condition in the superheater.

In some cases it may be necessary to reduce the backpressure on the safety valve to less than the typical 10 % of set pressure in order to maintain a Class 150 outlet flange. Reducing the backpressure is preferable to specifying a Class 300 outlet flange because the inlet class to achieve this may be much higher than required.

13.2.4 System Considerations

ASME *BPVC* Section I prohibits valves between the protected equipment and the safety valves, and between the safety valve and atmosphere. There are two implications for this requirement:

— installed spare relief capacity cannot be provided, and

— the discharge from the safety valve cannot be routed through a header system that contains an isolation valve such as a process unit flare header.

If the design pressures are selected correctly, the boiler safety valves can be used to protect the refinery steam header from a blocked outlet. To meet this objective, the maximum accumulation pressure of the steam drum (MAWP + 6 %, per ASME *BPVC* Section I) shall not exceed the allowed accumulation pressure for the header. Otherwise, additional relief protection is required at the header.

13.3 Flow Meters

13.3.1 Purpose

Flow elements are essential part of the control loop for boiler control systems and also provide useful information for records. Flow elements measure flows for air, steam, and water to provide input to control loops to keep the regulated process variable and as close as possible to the desired set point.

Flow inputs for boilers are most commonly used in the following control loops:

a) air and fuel gas flow control, ratio and fuel metering,

b) BFW control.

Accurate flow metering is also essential for:

a) boiler performance testing,

b) maintaining efficiency and minimizing emissions by fuel air ratio control.

13.3.2 Flow Measurement

The basic methods for measuring water, steam, air and gas flow, considering the accuracy requirements of the ASME *PTC* are by orifice, flow nozzle (flow tube) or venturi tubes as primary elements. The advantages and disadvantages of these three types of flow elements are listed in Table 31. The flow can be derived from the pressure drop differential created by these elements by the equation as noted below.

$$M = C_q YA[2g_c\rho_1(P_1 - P_2)/(1 - \beta^4)]^{1/2}$$

where

M is the flow rate, lb/s;

C_q is the coefficient of discharge, dimensionless and is dependent on the device used and installation;

Y is the compressibility factor, dimensionless; equals 1.0 for most liquids and foe gases where the pressure drop across the device is less that 20 % of the initial pressure;

A is the cross-sectional of the throat, ft^2;

g_c is the proportionality constant, 32.17 lb ft/lbf s^2;

P_1 is the upstream static pressure, lb/ft^2;

P_2 is the downstream static pressure, lb/ft^2;

β is the ratio of the throat diameter to the pipe inner diameter, dimensionless;

ρ_1 is the density at upstream temperature and pressure, lb/ft^3.

Table 31—Flow Elements Advantages and Disadvantages

	Orifice Advantages	**Orifice Disadvantages**
1	Lowest initial cost.	High non-recoverable lead loss (energy cost)
2	Easily installed and replaced.	Suspended matter may build up upstream at the inlet side of horizontal installations, causing erratic pressure drop measurements, unless eccentric or segmental types of orifices are used with the bore flush with the bottom of the pipe
3	Well established coefficient of discharge, C_q	Low capacity
4	Will not wiredraw or wear in service during test period	Requires pipeline flanges
5	Sharp edge will not foul with scale or other suspended matter	
	Flow Nozzle Advantages	**Flow Nozzle Disadvantages**
1	Can be used where no pipeline flanges exist	Higher cost than orifice
2	Less costly than venturi tubes of the same capacities.	Same head loss than as an orifice for the same capacity
		Inlet pressure connections and throat taps shall be fabricated with precision
	Venturi Tube Advantages	**Venturi Tube Disadvantages**
1	Lowest head loss	Highest cost
2	Has integral pressure connections	Greatest weight and largest size for a given line size
3	Requires the shortest straight length upstream	
4	Will not obstruct flow of suspended matter	
5	Coefficient of discharge well established	

Details for primary element sizing and fabrications can be obtained from ASME's *Fluid Meters, Their Theory and Application*.

Materials—When selecting materials for the primary elements, due consideration shall be given for corrosion and erosion. The engineer shall consider the erosive effects of the high velocity and the likelihood of water in saturated steam.

13.3.3 Considerations for Primary Element Installation

The engineer shall consider the following when selecting the primary element type, as they affect the flow measurement accuracy and have an impact on plant layout of ductwork and piping design.

To maintain accuracy, most elements require that there be no flow disturbances upstream and downstream of the elements; the engineer shall consult with the manufacturer for exact requirements.

a) The location of the flow element in relationship to elbows, bends or changes in cross-sectional area.

b) The location of the flow element in relationship to flow control valves or dampers.

c) Location and types of pressure taps.

d) The use of flow straightening devices upstream of flow elements.

13.3.4 Flow Measurement for Combustion Air and Fuel Gas for Control

The following are flow measurement requirements for combustion air and fuel gas.

a) In all but the simplest of boiler applications, fuel gas flow and combustion air flow measurements are required to maintain the proper air fuel ratio to maximize efficiency and to minimize the formation of NOx by minimizing excess air. Stack excess oxygen or CO_2 measurements in the flue gas are used to bias the fuel-to-air ratio controls.

b) The engineer should consider that the utilization of excess oxygen alone in the flue gas may not be the most optimal method for fuel air ratio control, as it depends solely on the excess oxygen probe and its corresponding analyzer.

c) Combustion air flow may be measured by the following types of elements.

   1) Pitot tubes that measure the velocity and static pressures to generate a differential pressure, which is an indication of flow. Pitot tubes have a flow coefficient of 1.0 and, therefore, have minimal head losses.

   2) Thermal dispersion probes that provide flow measurement by sensing the cooling effect of the air flow on probes with internal electrical heating elements. These elements are very accurate in low flow applications when the duct velocities and velocity head is very low.

   3) A venture air foil in a section for the air duct that generates a differential pressure based on the differences in velocity, following Bernoulli's equation. To maintain accuracy, the venturi element requires a proportionately longer section of duct for the element itself and also requires some straight sections of duct upstream and downstream of the venturi. To offset the latter and to minimize plot space, venturi ducts can be located on the inlets of FD fans that have top inlets.

13.3.5 Temperature and Pressure Corrections

Since the desired output is usually desired in terms of mass flow, the density may be corrected as it is a function of the absolute temperature and pressure. Therefore, in all cases excepting fluids at ambient pressures and temperatures, the temperatures and pressures of the fluid near the flow elements are measured by transmitters and a signal is provided to the BPCS for the density is corrected via algorithm to provide a true indication of mass flow.

13.4 Control Valves

13.4.1 Purpose

The control valve is the most common final control element in the control loop for boiler control systems. The control valve manipulates flowing fluid, such as steam, gas, or water, to compensate for deviations in flow disturbances and to keep the regulated process variable as close as possible to the desired set point.

Control valves for boilers are most commonly used in the following control loops:

a) fuel gas flow control,

b) BFW control,

c) attemperating water control for desuperheaters associated with steam temperature control,

• d) where specified, start-up vents on steam outlet headers; sometimes referred to as “sky valves,”

e) steam drum blowdown control valves.

13.4.2 Types of Control Valves—General

The following are characteristics and requirements for control valves.

a) The two major type categories are rotary and sliding stem. Refer to Figures 5A and 5B of API 553.

b) The control valve consists of a valve body assembly, actuator assembly, and accessories, typically specified as one complete unit manufactured, assembled, and tested at the manufacturer’s facility.

• c) The valve body assembly contains the process fluid and consists of the body, internal trim, bonnet, and sometimes a bottom flange and/or bonnet flange. The valve body assembly shall meet all of the process design conditions for pressure, temperature, and corrosion requirements of the connecting piping and boiler, as a minimum. For the design pressure, the engineer shall also consider the shut in conditions, e.g. BFW pump maximum total development head (TDH) plus the deaerator’s design pressure.

• d) Design considerations for the valve body shall be in accordance with API 553 with the additions noted below.

   1) The maximum differential pressure for BFW control valves, considering start-up conditions (zero pressure downstream). The choice of materials for the trim, body, and downstream piping shall also take into consideration the fact that the feedwater is at the flashing point.

   2) The engineer should also consider a smaller capacity, manual bypass valve, located near to the BFW valve, and manufactured with the same considerations as above for metallurgy.

   3) The materials for the trim and body for start-up, steam-vent, and sky valves shall also be selected, considering maximum differential pressure (boiler design pressure) as the steam is being vented to atmosphere.

4) Threaded valves should not be used in boiler steam, water, and in fuel and igniter gas services.

5) Flangeless valves should not be used in boiler steam, water, and in fuel and igniter gas services.

6) For control valves in continuous blowdown service, the valve size shall be the same size as the connection on the steam drum.

7) The engineer shall consider the characteristic of the control valve, as installed within the boiler's system, considering the frictional pressure drops of the piping, economizers, and the static pressure and variations in upstream pressure. Fuel gas control valve characteristics shall also consider the pressure vs capacity curves of the burner(s), from rated capacity to burner turndown.

8) The sizing of the BFW control valves shall consider the installed valve flow characteristic of the valve and the head vs flow capacity curve of the boiler feed pump(s), from boiler rated capacity to turndown.

9) Choked flow shall be considered for the sizing of start-up vent and sky valves.

10) Special cavitation control trim shall be considered for BFW control valves.

11) BFW and steam drum continuous blowdown valves are at, or just below, the flash points, larger size control valve bodies shall be considered.

12) Boiler control valves that are high contributors to high noise levels include BFW valves, steam valves, and in particular, start-up vent valves. For the latter, steam silencers are used on the discharge piping of the valve to reduce noise. However, the noise level of the valve itself shall be limited to 110 dB(A) to preempt mechanical failure.

13.4.3 Valve Actuators

Design considerations for valve actuators shall be in accordance with API 553, with the additions noted below.

a) The minimum anticipated air pressure shall be used for sizing the actuator for normal operating service; the plant's maximum air pressure shall be used and specified for the mechanical design of the operator. Requirements for opening and closing times, for normal process and failure modes (i.e. loss of plant air or control signal) shall be met at the minimum air pressure.

b) Where solenoids are used, the Cv of the solenoid and the size of its ports and interconnecting tubing shall be considered, as it may impact open and closing times.

c) Electric actuators may be used where step control is preferred, e.g. for continuous blowdown control valves.

13.4.4 Switches and Solenoids

Design considerations for switches and solenoids shall be in accordance with API 553, with the additions noted below.

• a) For low voltage solenoids, the voltage drop through the wiring shall be evaluated, especially when the distances from the power supply to the solenoid are appreciable. Low-power solenoids (<1.4 W) are available and may be considered when the power supply has limited capacity. The engineer shall also specify the ambient temperature range for the solenoid valves and explosion proof construction.

b) In addition to hermetically sealed limit switches, consider positioners with the capacity of transmitting the valve's position as either a discreet digital signal or an analog signal (or both) if the valve is in a safety critical or SIS service.

14 Tube Cleaning

14.1 Internal—Chemical, Mechanical

14.1.1 Internal Cleaning Decision for New Boilers

14.1.1.1 General

A new boiler should be thoroughly inspected before the decision is made to clean either with an alkaline boilout or a full acid cleaning. The cleaning is specific for economizer and generating tubes. Superheater tubes are only steam blown prior to start-up. Some of the factors that will affect the decision are as follows.

a) Boiler Construction—If the boiler was assembled at the construction site, cleaning is often required, especially if the tubes were rolled into the drums at the site. The rolling process utilizes lubricating oils to facilitate extrusion of the tube into the boiler. The oils should be removed. If the boiler was assembled as the site and the tubes were in an exposed laydown yard they will typically be rusted and require acid cleaning. A thorough inspection will tell the owner what is needed.

b) The Storage of the Boiler During Construction—If the boiler has not been laid up correctly (i.e. not stored in a dry and inert atmosphere) or if there is a significant time delay acid cleaning may be required.

c) Boiler Configuration—For example, if all sections of the boiler are not drainable, mineral acids should not be used.

d) Operating Pressure of the Boiler—The higher the pressure the more likely it is that the boiler should be acid cleaned.

14.1.1.2 Start-up vs Waiting Until After Start-up to Clean

If a facility is starting up a number of boilers (as in a utilities network) personnel may opt to clean some of the boilers and delay acid cleaning one or more until after start-up, particularly if the start-up involves a fairly complex condensate system. The logic is that start-ups are almost always problematic. Problems develop with pretreatment systems, as well as the condensate system. Condensate system cleanup is always a challenge so contamination of the boilers is a high potential.

Many operators will acid clean some of the boilers and store them until the systems are lined out, electing to use one or more uncleaned boilers during the start-up, with the intent of shutting them down after the start-up to then clean them.

14.1.1.3 Alkaline Boilout

Alkaline boilout is typically applied to pre-commissioning of new boilers. Follow the boiler manufacturer's recommended pressure for the alkaline boilout. Field erected boilers typically are contaminated with lubricating oils or greases used to roll the tubes into the tube sheets. Alkaline boilouts are necessary to remove these oils and greases and for removal of hydrocarbon contamination.

There is some data that suggests that an alkaline cleaning can improve the effectiveness of an acid cleaning as it can loosen the bond between scale and metal. Table 32 lists the components of an alkaline boilout and their function. The choice of alkaline compounds is wide, but to avoid the possibility of stress corrosion cracking, simple sodium hydroxide is avoided. Typically, a trisodium phosphate and a non-ionic surfactant solution are utilized. Sometimes disodium phosphate is added. The non-ionic surfactant helps to release the oils. There are other recipes that have been used. Sodium nitrate can be used to prevent caustic embrittlement if there is free caustic in the boilout formulation.

$Na_3PO_4 \Leftrightarrow 3Na^+ + PO_4^{-3}$ trisodium phosphate

Other buffers that could replace caustic and do not cause excessively high pH include the following:

$NaHCO_3 \Leftrightarrow Na^+ + HCO_3^-$ Sodium bicarbonate (baking soda)

$Na_2CO_3 \Leftrightarrow 2Na^+ + CO_3^{-2}$ Sodium carbonate (soda ash)

NOTE Precautions to take during alkaline boilouts are covered in F.4.6.

Table 32—Alkaline Boilout

Component	Function
High-quality water (no hardness)	Hardness will precipitate in the high pressure boilout solution
Trisodium phosphate, TSP	pH buffer, and elevates the pH to make oils and greases more soluble in the boilout liquid
Soda ash	Elevates the pH to make oils and greases more soluble in the boilout liquid
20 % sodium nitrate ($NaNO_3$)	Caustic embrittlement inhibition
Non-ionic surfactant	Makes oil and grease more soluble

14.1.2 Existing Boilers

14.1.2.1 Determination of the Need to Clean

Cleaning is needed when scale builds up on the boiler tube interior. Parameters that impact the amount of scale in boiler tubes include: hardness excursions, baseline hardness level in feedwater, iron or copper in feedwater, hours of operation, heat flux, percent of full capacity, type of treatment program (precipitating or transport), and water treatment chemistry out of specified range. Cleaning is generally limited to the inside of economizer and generating tubes. Superheater tube cleaning should only be done after discussion with a qualified consultant and the boiler manufacturer.

Various methods can be used to determine the presence and amount of scale. Nondestructive methods include boroscope inspections and Turner Gauge use. Quantitative guidelines for cleaning are most often defined by deposit weight density (DWD), which requires removal of a tube and removal of the deposit by glass bead blasting (per ASTM 3483). Removal of a tube should be from the highest heat flux area of the generating tubes.

Table 33 lists the DWD guideline levels for cleaning. These guidelines do not consider the scale composition, such as its copper content, scale insulating properties, and hence are conservative. These are guidelines only and should not supersede any related customer experience or boiler manufacturer guidelines.

Table 33—Cleaning Guideline Based on Boiler Pressure and Deposit Weight Density

Boiler Pressure psi (ga)	**Deposit Weight Density** grams/ft^2
≤4150 kPa (ga) [600 psi (ga)]	55
4150 to 6200 kPa (ga) [601 to 900 psi (ga)]	45
6200 to 8300 kPa (ga) [901 to 1200 psi (ga)]	35
8300 to 10,345 kPa (ga) [1201 to 1500 psi (ga)]	25

Boiler scale sample removal and analysis is accomplished by performing the following.

a) Tube removal.

Tube removal for deposit sampling should be done in accordance with ASTM D887. Selecting the location of tube samples from a boiler for deposit measurement and analysis is most important since deposits may vary appreciably in different parts of the boiler. Ideally, a high heat flux area or a problematic area should be selected.

It is recommended to remove a tube sample 0.9 m (3 ft) in length from locations that generally represent areas of maximum heat flux, corrosion potential and/or scaling potential. This will allow DWD, deposit analysis, and test cleanings to be performed. It is possible to determine DWD with smaller samples, but there is a higher risk of the sample not being representative.

b) Deposit sampling.

Depending on the orientation of the tube to hot flue gases, one side of the internal circumference will be hotter than the other. When measuring DWD, it is advisable to test the hot and cold sides of the tube, as typically the hot side has a greater DWD than the cold side. The hot side to cold side DWD ratio provides additional information on the relative heat flux on the tubes. DWD determinations should be done in accordance with ASTM D3483, Method A or B. Method B is a bead blasting procedure that yields slightly higher results, but is more reliable.

Chemical analysis of the deposits is required to determine the deposit composition. This information is used to determine the type of cleaning and the steps required. Table 34 lists the analyses and results obtained.

Table 34—Chemical Analysis of Internal Tube Deposits

Analysis	Results
Loss on ignition	Percent water of hydration and organics
X-ray fluorescence of ash	Elemental analysis
Acid digestion and inductively coupled plasma (ICP) of ash	Total metals
X-ray diffraction of deposit	Compounds
FTIR	Organic functional groups by major classification

c) Metallurgical analysis of the tube sample.

This is used to help determine the root cause of a failure, corrosion mechanism, or overheating that has occurred.

14.1.2.2 When to Use Mechanical vs Chemical Cleaning

Either procedure should be performed by a qualified/experienced cleaning contractor. In general, chemical cleaning is the recommended approach. Mechanical cleaning may be done as a precursor to chemical cleaning for a heavily fouled boiler.

Mechanical cleaning is typically done using hydroblasting.

Mechanical cleaning advantages are as follows.

a) May be quicker if deposits are limited to a few tubes.

b) Used if the deposits are fairly easy to remove mechanically or as a precleaning step (prior to chemical cleaning) in heavily fouled systems.

Mechanical cleaning drawbacks are as follows.

a) Difficult to ensure that the tubes are completely cleaned, short of complete fiber optic inspection.

b) Difficult to ensure all removed solids are flushed out.

c) Less effective for scale removal.

d) Less effective on oils and greases, as they tend to yield to mechanical pressure versus being removed.

e) Impractical to clean hundreds of tubes and ensure cleanliness, especially in large boilers where tubes can exceed 9 m (30 ft) in length.

Chemical cleaning advantages are as follows.

a) Liquids completely contact all surfaces, assuming tubes are not completely plugged.

b) Properly designed solvents and concentrations are very effective at removing deposits.

c) Analysis of the cleaning solution allows deposit removal assessment.

Chemical cleaning drawbacks are as follows.

a) Potential for excessive corrosion due to improper monitoring and/or control.

b) The boilers have to be completely isolated for entry and protection of superheaters, ancillary equipment, etc.

c) Chemical disposal can be an issue [hazardous, toxic, chemical oxygen demand (COD) load on wastewater treatment plant].

d) Effective chemical distribution is critical to a good chemical cleaning.

e) Neutralization, flushing, and passivation are critical to a proper acid or chemical cleaning.

14.1.2.3 Identify Possible Cleaning Solutions

14.1.2.3.1 General

The object of chemical cleaning is to remove mill or other scale, hardness, flash rust, iron, or copper, either by total dissolution/sequestration or by making it so loose it is removed during the rinsing/flushing phases. The large amounts of iron present in various forms in such scales present a separate problem of their own. It is acceptable to dissolve the scale and bring iron into solution. Ferric, or trivalent iron, ions, however, are severely corrosive to elemental iron, unless a method is used to deactivate them:

$$2\ Fe^{+3} + Fe \Rightarrow 3\ Fe^{+2} \text{ (ferric iron corrosion)}$$

To deactivate this ferric iron, it can either be reduced to ferrous (divalent) ions, or sequestered. Sequestering is to combine it with other species in a stable complex, which effectively removes it from the reaction.

There are a number of solvents that can be used for cleaning or metals removal from boilers: hydrochloric acid, citric acid (sometimes ammoniated), hydrofluoric acid, sulfamic acid, ethylenediaminetetraacetic acid (EDTA), etc. The solvents and deposits that they will clean are listed in Table 35. Inhibitors are recommended to be used with most acids in order to protect the base metal during the chemical cleaning process. The cleaning consultant/contractor should recommend an acid inhibitor for the specified cleaning chemical.

Refer to Annex G for additional guidance on chemical cleaning procedures.

Table 35—Deposits and Typical Cleaning Solutions

Deposit Type	Typical Cleaning Solution
Hardness [$CaCO_3$ and $Mg(OH)_2$]	Hydrochloric acid, citric acid, ethylenediaminetetraacetic acid (EDTA)
Iron oxide	Hydrochloric, ammoniated citric, EDTA
Copper	Thiourea in hydrochloric acid
Copper oxide	Ammonium bromate, ammonium persulfate
Calcium sulfate	EDTA
Hardness with silica, e.g. magnesium silicate	Hydrochloric acid with ammonium bifluoride
Calcium carbonate	Sulfamic acid
Hydrocarbon	Trisodium phosphate, caustic plus non-ionic surfactants, or caustic with potassium permanganate

The material safety data sheet (MSDS) should be consulted for all chemical cleaners.

14.1.2.3.2 Inhibited Hydrochloric Acid

Inhibited hydrochloric acid is a most widely used solvent since it produces good solubility with a wide variety of scales. It exhibits good corrosion characteristics when correctly inhibited and the process is controlled within accepted limits. The process is flexible and can be modified to complex copper by the addition of thiourea, or to enhance silica removal by the addition of ammonium bifluoride. Hydrochloric acid is not very effective on calcium sulfate deposits.

Caution—Stainless steel is not compatible with hydrochloric acid. Exposure of stainless steel to hydrochloric acid results in chloride stress corrosion cracking.

14.1.2.3.3 Citric Acid/Ammoniated Citric Acid

Even without the addition of NH_3, citric acid will dissolve both ferrous and ferric oxides, forming stable complexes in solution that inhibit ferric iron corrosion. Experience shows, however, that ferric iron will precipitate over time. The addition of NH_3 to a pH of roughly four forms the species mono-ammonium citrate ($C_6H_7O_7{\bullet}NH_4$) and di-ammonium citrate [$C_6H_6O_7{\bullet}(NH_4)_2$]. This stabilizes the iron complex and prevents precipitation. Both of these additives are highly effective in sequestering ferric iron, ferrous iron and low levels of cupric copper. To remove deposits of up to 8 % copper, a separate copper removal step is needed, where the pH is raised to 9 with NH_3 and an oxidizer (e.g. sodium nitrite) is added.

14.1.2.3.4 Ammonium Bifluoride, NH_4HF_2

This chemical is added to hydrochloric acid for silicate removal, especially serpentine ($Mg_3Si_2O_7{\bullet}2H_2O$). Addition of this chemical to citric acid contributes to the ammoniating process described above. It forms hydrofluoric acid in solution, which is largely undissociated. This is because hydrofluoric acid is a weak acid, with the hydrogen and fluoride components having affinity for one another. This, however, does not stop it from reacting with, among other things, silicate scales such as acmite [$NaFe(SiO_3)_2$]:

$$Na_2O{\bullet}Fe_2O_3{\bullet}4SiO_2 + 36HF \Rightarrow 2FeF_6^{-3} + 4H_2SiF_6 + 2Na^+ + 4H^+ + 12H_2O$$

14.1.2.3.5 Hydrofluoric Acid, HF

Hydrogen fluoride ionizes in aqueous solution in a similar fashion to other common acids:

$$HF + H_2O \Rightarrow H_3O^+ + F^-$$

Due to its low degree of ionization in dilute solution, hydrofluoric acid is the only hydrohalic acid that is not considered a strong acid. Hydrofluoric acid complexes the ferric ion to prevent ferric ion corrosion and removes silica scales. It is rarely used by itself, but if used by itself or in combination with hydrochloric acid, an inhibitor is needed. It is most frequently generated by adding ammonium bifluoride to hydrochloric or citric acid. Extreme caution shall be exercised when handling hydrofluoric acid.

14.1.2.3.6 Ethylenediaminetetraacetic Acid (EDTA)

EDTA is a chelating agent that is used to remove iron oxide, copper, and hardness scales (in particular calcium sulfate). It requires higher temperatures and longer circulation time than other chemicals in order to achieve satisfactory cleaning. Cleaning times can be one to four days. Good circulation is needed for it to be effective. Its most attractive feature is that corrosion rates are low under properly controlled conditions. Ammonium EDTA is used for removing hardness salts and iron oxide at about 9 pH.

14.1.2.3.7 Sulfamic Acid (H_3NSO_3)

Sulfamic acid has the advantage of being a crystalline solid that is simple to store, handle, and mix. When compared to most of the common strong mineral acids, sulfamic acid has desirable water descaling properties, low volatility, and low toxicity and is a water soluble solid forming soluble calcium and iron-III salts. It finds application FDA approval is needed. It is frequently supplied with the inhibitor and a color indicator of effective acid strength added. It is compatible with stainless steels and is a moderately aggressive solvent for iron oxide and calcium carbonate. It is infrequently used in industrial boilers because it is less effective and more expensive than other acids.

14.1.2.3.8 Thiourea [$CS(NH_2)_2$]

Thiourea is used in conjunction with hydrochloric acid to sequester copper that has been dissolved by hydrochloric acid.

Caution—Maintaining adequate concentration to sequester the copper is critical to prevent re-deposition of the copper.

14.1.2.3.9 Hydrocarbon Removal

Alkaline boilout for new boilers was covered previously. This section deals with hydrocarbon scale from hydrocarbon leaks into the feedwater system, especially heavy hydrocarbons, which fouls the boiler. Light hydrocarbons will vaporize into the steam and may not foul the boiler. If there has been an excursion of hydrocarbon in the feedwater, there is a high potential for contamination of the entire steam system due to carryover and foaming from the boiler. Turbines should be monitored for fouling. Condensate systems should be checked and blown down if needed. Condensate tanks should be skimmed. Condensate polishers should be checked for contamination.

Taking a sample of the foulant is strongly recommended in order to determine the cleaning procedure. Various alkaline solutions may be applicable, including 2 % to 3 % trisodium phosphate, potassium permanganate and sodium hydroxide, or organic solvents. If there are also inorganic foulants, then alkaline cleaning may be followed by an acid cleaning.

14.1.2.4 Conduct a Chemical Cleaning Test

A cleaning test on a portion of the tube sample should be conducted by a qualified chemical cleaning company to determine the appropriate solvents for the specific deposits and to prepare the cleaning procedure.

14.1.2.5 Develop a Detailed Cleaning Plan

A detailed cleaning plan is generally prepared by the cleaning consultant or contractor and should include the following:

a) the cleaning solutions, temperature, and time for each cleaning step;

b) the method for contacting the cleaning solution with the boiler tubes;

c) the method for heating the cleaning solution;

d) the need for additional access points or drains on the boiler;

e) a site review to determine the staging of cleaning facilities;

f) the disposition of cleaning waste;

g) a contingency plan for leaks/spills;

h) a repair plan if the cleaning results in leaks;

i) definition of lab or field analyses that will be done to monitor the cleaning progress and on what frequency;

j) the test that will be performed to determine the adequacy of inhibitors;

k) the monitoring/coverage plan.

NOTE See F.4.8 for a typical boilout procedure.

14.1.2.6 Neutralization and Passivation After Acid Cleaning

Prior to neutralization, the acid shall be flushed from the boiler. Any remaining acid needs to be neutralized using typically a 1 % sodium carbonate solution. For chemical cleaning using other organic acids, EDTA, or multi-step cleaning procedures, the chemical cleaning specialist should provide the neutralization and passivation steps.

14.1.2.7 Postcleaning Inspection

A postcleaning inspection, which may include taking a tube sample, should be conducted to ensure the cleaning has been effective. Passivation chemicals are drained out and air is blown through the unit for inspection. Solids are further flushed out of the tubes and headers with high-pressure water hoses. Steam drum internals are reinstalled and site glasses are replaced when the boiler is determined to be safe to enter.

14.1.2.8 Start-up Postcleaning

Start-up postcleaning should include higher than normal blowdown rates, passivating agent, and dispersing polymer dosages. Consult with the water treating specialist for a plan that is specific to your treatment chemistry. Additional monitoring during start-up shall include performing the Babcock and Wilcox iron filtration test.

14.2 External—Sootblowers

14.2.1 General

API 534 is the primary source for the following description regarding external tube cleaning.

API 538's scope encompasses external tube bundle cleaning. Flue gas side tube cleaning devices are primarily blowing media cleaners or sootblowers. Sootblowers in refinery/petrochemical boilers normally use steam, but other types are available (e.g. air and acoustic devices). Sonic cleaning and shot cleaning are seldom used. Other design considerations for sootblowers that clean the furnace, APHs, and catalyst (NOx control) are not within the API 538 scope. Design considerations for water sootblowers (lances and/or cannons) are not within the API 538 scope. Furnace wall blowers are not within the scope of API 538 either.

- Sootblowers are required when heavy oil is fired and extended surface tubes 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. Sootblowers shall be automatic, sequential and/or fully retractable, as specified by the purchaser.

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.

When NH_3 and sulfur compounds are present, the potential for fouling and possible sootblower use should be considered. Sootblowers may also be required when the boiler is exposed to ash or catalyst dust.

Sootblowers are either fixed position rotary or retractable types.

a) 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.

b) Retractable sootblowers may be either fully or partially retractable. 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. Fully retractable types are not subject to the debilitating effects of temperature and foulants when not in service. The lance is retracted outside of the boiler when not in use. An air bleed/check valve prevents flue gas from entering the lance. Retractable sootblower entrance ports (through the refractory wall) are generally stainless steel sleeves.

14.2.2 System Considerations

14.2.2.1 Design

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

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

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.

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

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 decrease the cleaning ability of the sootblower. Blowing pressure typically ranges between 690 kPa (ga) [100 psi (ga)] to 2070 kPa (ga) [300 psi (ga)]. With a minimum steam pressure of 1030 kPa (150 psi) at the inlet flange, individual sootblowers typically should be designed to pass a minimum of 4500 kg/h (10,000 lb/h) of steam.

For temperatures over 540 °C (1000 °F), retractable blowers are desirable. The rotary type is subject to potential oxidation and drooping of the rotary lance. Retractables are also used when the tube bank is wider than can be covered with a rotary unit.

Positive pressure wall sleeves with sealing air are required to prevent leakage of flue gases from positive pressure boilers. Sealed air blowers should be supplied as part of the sootblower package.

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

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

14.2.2.2 Operational Description

Sootblowers operational 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 boiler due to excessive quantities of the blowing media from being added to the flue gas.

14.2.2.3 Controls

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

14.2.2.4 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) an automatic thermal drain valve.

14.2.2.5 Retractable Sootblowers

14.2.2.5.1 Layout and Steam Consumption

Retractable sootblower layout and steam consumption are as follows.

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

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

c) Typical blowing steam consumption levels are given in Figure 34. Air is rarely used in retractable sootblowers.

d) Cleaning lanes for bare tubes should be a minimum of 380 mm (15 in.) clear between tubes' ODs. Cleaning lanes for extended surface tubes should be 460 mm (18 in.) between the tips of fins when the sootblower element (lance) is parallel to the tubes and 610 mm (24 in.) when the element is perpendicular to the tubes.

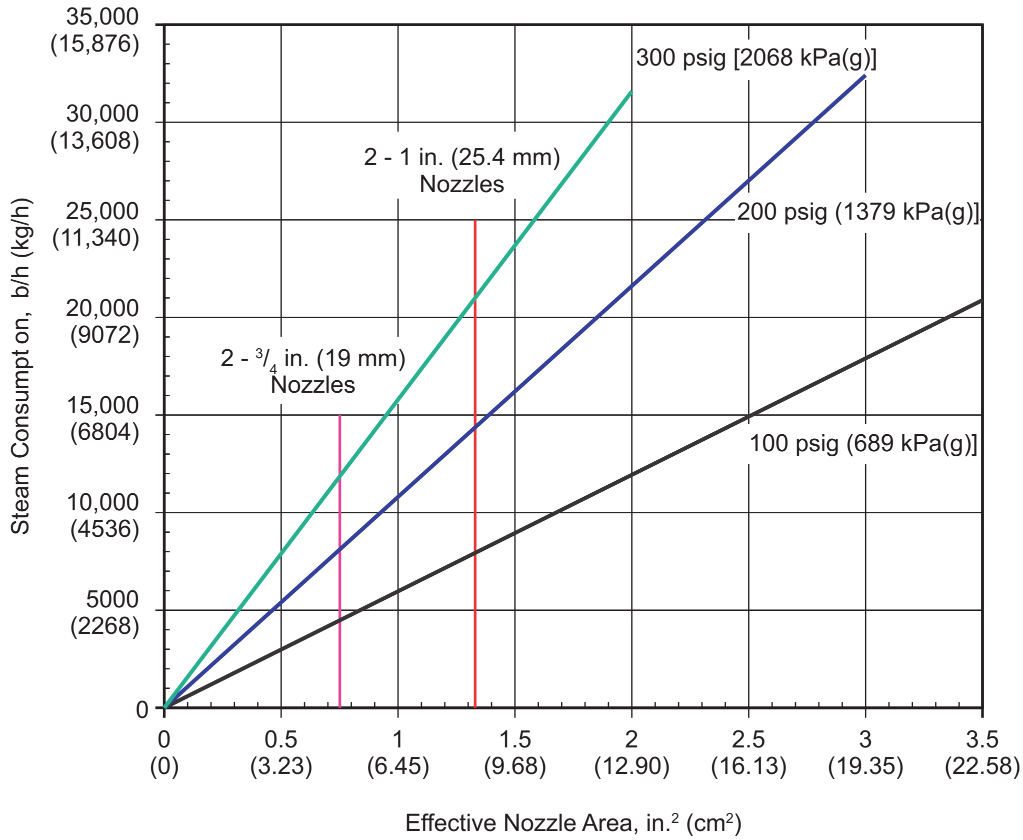


Figure 34—Typical Steam Flow Rate for Retractable Sootblowers

14.2.2.5.2 Mechanical Design and Construction

Sootblowers shall be designed and constructed to facilitate maintenance and inspection.

a) Major components, such as packing, poppet valve, carriage, etc., shall all be accessible to allow disassembly and assembly for online maintenance/inspection.

b) Carriages shall be accessible from the top and bottom of the sootblower.

c) Sootblowers shall be supported at the casing wall by a sleeve yoke and from a platform or structure outside the casing near the outboard end.

d) Sootblower housings shall be fabricated from 6.3 mm (0.25 in.) thick carbon steel.

Sootblowers shall be assembled in an ISO 9001 certified facility.

Component considerations are as follows.

a) Drive carriage:

   1) drive carriages shall be center balanced, supported by four rollers and have a dual rack and pinion drive gear and integral clutch mechanism located inside the gearbox;

   2) drive carriages shall be of modular design, made up of a gearboxes and lower housings that can be separated from each other.

b) Electrical:

   1) power and control wiring shall be enclosed in a flexible E-chain type carrier;

   2) junction boxes shall be rated NEMA 4X and made of stainless steel.

c) Poppet valves:

   1) poppet valves shall be capable of maintaining the rated blowing steam flow rate and pressure;

   2) poppet valves shall be designed and constructed as to allow for online pressure adjustment, using an external adjustment nut;

   3) blowing steam flow and pressure measuring taps shall be provided;

   4) valves shall be of non-leak design and construction.

d) Lance tubes:

   1) materials for lance tubes shall be selected to meet the specified flue gas temperature;

   2) droop of the lance shall be submitted as a “travel vs deflection curve” for each sootblower.

e) Feed tubes:

   1) the feed tube and lance tube of each sootblower shall be securely sealed without any leakage by means of packing;

2) packing shall be compressed suitably and evenly by means of a live loaded, cartridge type packing holder;

3) packing and cartridge holder shall be designed and constructed to allow compression adjustment during boiler operation and to allow for replacement by removing the lance and/or feed tube while the sootblower is mounted on the boiler.

f) Limit switches:

1) limit switches shall be NEMA 4, of the mechanical lever type. Each sootblower shall have one traveling limit switch mounted to the drive carriage.

g) Motors:

1) motors shall be TEFC, NEMA rated, and have Class F insulation.

h) Nozzle helix:

1) nozzles shall follow different paths during insertion and withdrawal;

2) nozzles shall index by way of an integral clutch located in the gearbox.

i) Surface treatment:

1) housings shall be hot-dipped galvanized according to ASTM A123;

2) motors, drive carriages, and support plates shall be painted using a two-layer alkyd enamel paint system;

3) poppet valves and wall boxes shall be painted using a high-temperature, single-coat, DTM paint system;

4) stainless steel, aluminum, bronze, brass, and copper are excluded from any surface treatment.

14.2.2.6 Fixed Position Rotary Sootblowers

14.2.2.6.1 Layout and Steam Consumption

Fixed position rotary sootblower layout and steam consumption are as follows.

a) If the tube bank exceeds 4.6 m (15 ft), rotary sootblowers shall be mounted on opposing sides of the tube bank.

b) Rotary sootblower maximum horizontal or vertical coverage shall be 900 mm (3 ft) from the element or three tube rows, whichever is less.

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

d) The number of nozzles for an element is based on providing one nozzle per space between tube rows. Actual consumption rates are a function of sootblower construction details. To provide adequate coverage for most industrial applications, multiple elements are normally installed.

e) See Figure 35 for steam consumption for fixed rotary sootblowers.

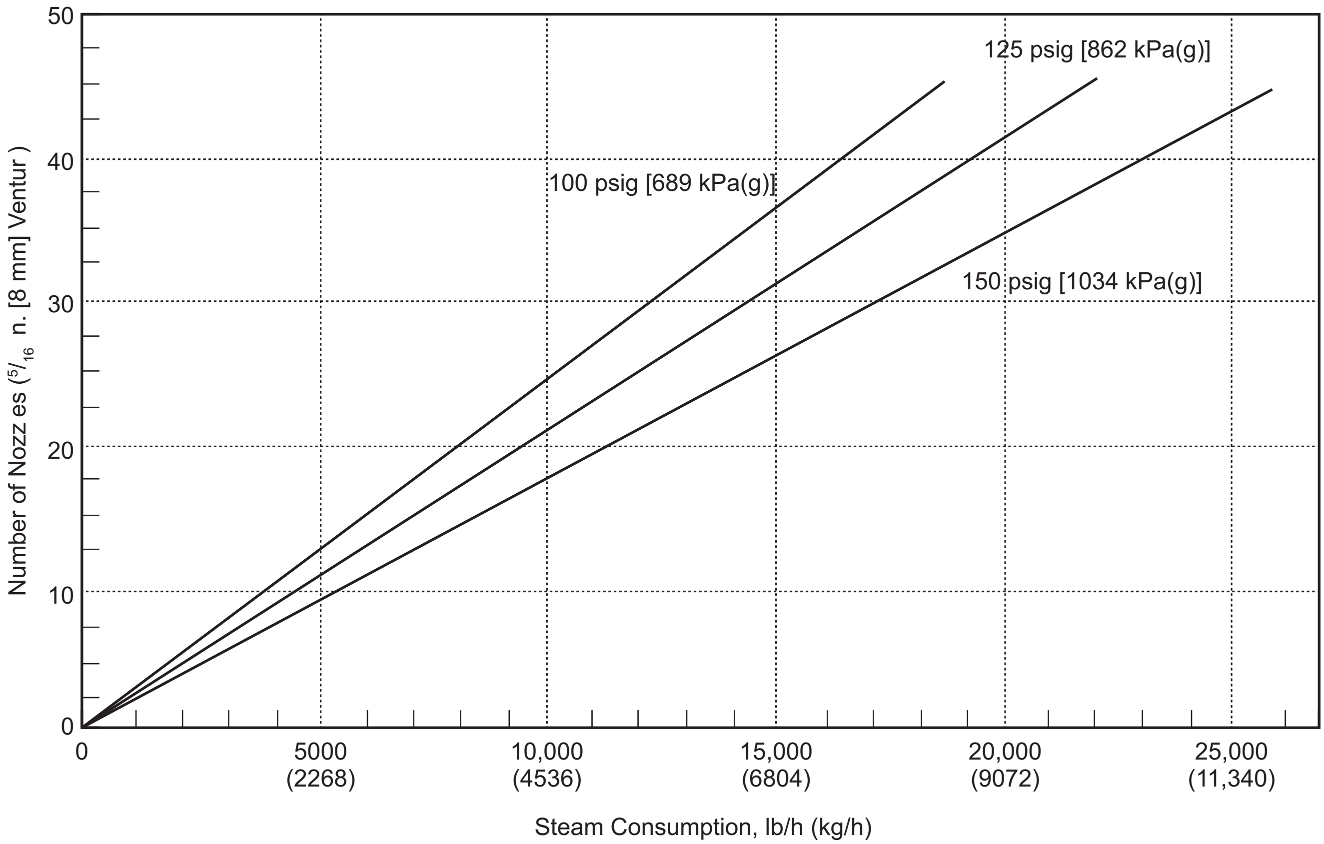


Figure 35—Typical Steam Flow Rate for Fixed Rotary Sootblowers

14.2.2.6.2 Mechanical Design and Construction

Sootblowers shall be designed and constructed to facilitate maintenance and inspection.

a) Major components, such as packing, poppet valve, etc., shall all be accessible to allow disassembly and assembly for online maintenance/inspection.

b) Carriages shall be accessible from the top and bottom of the sootblower.

c) Sootblowers shall be supported at the casing wall by a sleeve yoke. Fixed position rotary sootblowers are supplied as wall-mounted units without an end supporter from a platform or structure outside the casing near the outboard end.

d) Support brackets that are attached to tubes should be of the same material as the element. In the event the bracket temperature exceeds 590 °C (1100 °F) and the vanadium content of the fuel exceeds 50 ppm, 50 Cr-50 Ni (Cb) brackets should be used.

e) Sootblower housings shall be fabricated from 6.3 mm (0.25 in.) thick carbon steel and be hot-dipped galvanized according to ASTM-A123.

f) Sootblower rotation is provided by an electric motor drive.

g) The support brackets should be independent of the element.

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

   1) 1000 mm (40 in.) apart: 480 °C (900 °F);

   2) 750 mm (30 in.) apart: 815 °C (1500 °F);

   3) 500 mm (20 in.) apart: 980 °C (1800 °F).

i) Typical gas temperature limits for element materials are:

   1) carbon steel 425 °C (800 °F);

   2) chrome plated or calorized steel 540 °C (1000 °F);

   3) stainless steel (22 % Cr minimum) 815 °C (1500 °F).

Sootblowers shall be assembled in an ISO 9001 certified facility.

Component considerations are as follows.

a) Electrical:

   1) junction boxes shall be rated NEMA 4X and made of stainless steel.

b) Poppet valves:

   1) poppet valves shall be capable of maintaining the rated blowing steam flow rate and pressure;

   2) poppet valves shall be designed and constructed as to allow for online pressure adjustment, using an external adjustment nut;

   3) blowing steam flow and pressure measuring taps shall be provided;

   4) valves shall be of non-leak design and construction.

c) Element tubes:

   1) materials for lance tubes shall be selected as to meet the specified flue gas temperature.

d) Limit switches:

   1) limit switches shall be NEMA 4 and of the mechanical lever type.

e) Motors:

   1) motors shall be TENV, NEMA rated, and have Class F insulation.

f) Surface treatment:

   1) motors, drive carriages, and support plates shall be painted using a two-layer alkyd enamel paint system;

   2) poppet valves and wall boxes shall be painted using a high-temperature, single-coat DTM paint system;

   3) stainless steel, aluminum, bronze, brass, and copper are excluded from any surface treatment.

14.2.2.7 Advantages

14.2.2.7.1 Retractable Sootblowers

The advantages of retractable sootblowers include the following.

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.

14.2.2.7.2 Fixed Position Rotary Sootblowers

The advantages of fixed-position rotary sootblowers include the following.

a) Construction is less complex.

b) External platforms and structure minimized.

14.2.2.8 Disadvantages

14.2.2.8.1 Retractable Sootblowers

The disadvantages of retractable sootblowers include the following.

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.

14.2.2.8.2 Fixed Position Rotary Sootblowers

The disadvantages of fixed-position rotary sootblowers include the following.

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 where the sootblower element is exposed to temperatures in excess of 590 °C (1100 °F), or fuel oils containing large quantities of heavy metals (over 50 ppm vanadium) are used.

f) Rotary sootblowers may not be suitable when certain high fouling fuels are employed.

15 Structure, Setting, and Casing

15.1 General

API 560 is the primary source of the following description. Selected excerpts from the standard are included in this section for illustrative purposes only.

• a) The purchaser shall specify or agree to the structural design code. Structures shall comply with the structural design code.

b) Minimum design loads for wind and earthquake shall conform to the structural design code.

c) Platform live loads shall be in accordance with the structural design code.

d) 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 boiler 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.

• e) The metallic jacket covering the boiler insulation shall be galvanized carbon steel sheet or corrugated aluminum sheet. The jacket shall also be adequately reinforced to prevent buckling and vibration. Minimum thickness of the jacket may vary based on demonstrated experience of boiler vendor. Roof lagging may be thicker than vertical lagging in order to accommodate standing on the roof.

15.2 Platforms, Stairways, and Ladders

Platforms shall be provided as follows at:

a) burner and burner controls;

b) sootblower locations for maintenance and operation purposes;

c) all observation ports and firebox access doors not accessible from grade;

d) auxiliary equipment, such as steam drums, fans, drivers, and APHs, as required for operating and maintenance purposes;

e) all areas necessary to access instrument and sampling connections; and

f) oxygen/combustibles sample probe(s).

Stairway access shall be provided to platforms serving burners, burner controls, sootblowers, and the steam drum.

• Platforms shall have a minimum clear width as follows:

a) operating platforms: 900 mm (3 ft),

b) maintenance platforms: 900 mm (3 ft),

c) walkways: 750 mm (2.5 ft), and

d) platforms accessing observation openings: 750 mm (2.5 ft).

- Platform decking shall have a minimum thickness of 6.3 mm (0.25 in.) checkered plate or 25 mm by 5 mm (1 in. by $^{3}/_{16}$ in.) open grating, as specified by the purchaser. Stair treads shall be open grating with a checkered plate nosing. Stair treads and platforms shall be completely level.

  Dual access shall be provided to each operating platform, except if the individual platform length is less than 6 m (20 ft).

  An intermediate landing shall be provided if the vertical rise exceeds 9 m (30 ft) for ladders and 4.5 m (15 ft) for stairways.

- Ladders shall be caged from a point 2.3 m (7.5 ft) above grade or any platform. A self-closing safety gate shall be provided for all ladders serving platforms and landings. Ladders shall be arranged for side step-off. Step-through ladders shall not be used, unless specified or agreed by the purchaser.

  Stairs shall have a minimum width of 750 mm (2.5 ft), a minimum tread width of 240 mm (9.5 in.), and a maximum riser of 200 mm (8 in.). The slope of the stairway shall not exceed a 9 (vertical) to 12 (horizontal) ratio.

  Headroom over platforms, walkways, and stairways shall be a minimum of 2.1 m (7 ft).

  Handrails shall be provided on all platforms, walkways, and stairways.

  Handrails, ladders, and platforms shall be arranged so as not to interfere with tube handling. Where interference exists, removable sections shall be provided.

- Any obstructions on walkways, platforms, and stairs should be avoided. In the event an obstruction is unavoidable, it shall be clearly and brightly marked and illuminated. Any obstruction may not be instituted without the approval of the purchaser.

15.3 Observation Ports

Observation ports shall:

a) permit visibility of all burners and their flame envelope, all furnace surfaces, and the superheater cavity;

b) have minimum wall opening of 50 mm × 100 mm (2 in. × 4 in.) or be 75 mm (3 in.) in diameter; and

c) on pressurized boilers, observation ports shall have a view glass and shall be furnished with:

   1) aspirating air of sufficient pressure to prevent flue gases from blowing out when the door is open,

   2) seal air to minimize flue gas leakage and prevent fogging of the view glass when the door is closed.

15.4 Access Doors

Ample clear space, with a casing access door, shall be provided into the burner windbox, the boiler furnace, and between each boiler section (including stack and inlet and outlets of the APH) for maintenance access. The spacing between boiler sections and into the furnace shall be sufficient to permit repairing tubes, including necessary scaffolding.

16 Flue Gas Sampling Connections

Connections shall be provided in each stack in compliance with environmental air-quality monitoring requirements, as specified by the appropriate regulatory body. Sampling point locations shall be determined according to environmental requirements regarding upstream and downstream flow disturbances.

Unless dictated otherwise by the local environmental permitting agency, the connections shall be DN 100 (4 NPS) schedule 80 pipe with a Class PN 20 (ASME Class 150) raised-face flange. The pipe shall be welded to the outside casing plate and project 200 mm (8 in.) into the face of the flange. The boiler vendor shall furnish for each connection a Class PN 20 (ASME Class 150) blind flange with appropriate gaskets for the temperature and corrosive conditions of the flue gas. The pipe shall extend 38 mm (1.5 in.) into the boiler stack from the hot face.

- Additional connections to meet applicable governmental or local environmental requirements shall be specified by the purchaser.

17 Computational Fluid Dynamics and Cold Flow Modeling

API 536, Annex C is the primary source of the following description. Selected excerpts from the standard are included in this section for illustrative purposes only.

CFD and cold flow modeling are tools used to ensure proper burner air distribution and boiler flue gas flow distribution. The boiler furnace and burner windbox can be flow and thermal mass modeled over the complete operating envelope to ensure the proper design, which includes the following.

a) The flame profile of the burners relative to each other and the furnace dimensions.

b) Flue gas and combustion air mixing point to the burner windbox for systems having FGR. This location is upstream of the FD fan to ensure the combined stream has ample distance prior to the burner windbox to achieve thorough mixing. No CFD modeling is warranted.

c) Windbox design to achieve uniform peripheral flow distribution of oxygen to each burner.

d) Transition pieces between boiler sections (e.g. upstream and downstream of the economizer).

It is important to ensure that combustion air is distributed equally among all the burners. CFD and cold flow modeling objectives for the burner windbox design include the following.

a) Minimize air flow deviations to each burner; acceptable criteria should be less than +2 %.

b) Equalize peripheral air velocity to achieve equal air mass flow around and through the periphery of the diffuser. Maximum allowable peripheral velocity deviation shall be less than +15 % of the mean velocity for each burner.

c) Have swirling air create air recirculation zones to provide low velocity flame “anchor” points for burner flame stability over burner operating range.

While carrying out CFD analysis, the following points shall be considered.

a) The CFD software shall be an up-to-date version from an established software licensor.

b) 3D volume of the system under consideration shall be divided into an adequate number of computational cells. Critical parameters in building and evaluating a CFD model are the mesh or grid size and whether the mesh is yielding sufficient resolution.

c) CFD analysis shall be carried out for the design and turndown load of the system.

d) The CFD model shall demonstrate convergence and accuracy in the solution to agreed-upon requirements.

e) The final CFD model results shall include three-dimensional graphics showing expected velocity and temperature deviation within the windbox and throughout the furnace. The final CFD results shall also include tables summarizing maximum, minimum, average, standard deviation and RMS velocity, and temperature.

f) It may be necessary to introduce static gas mixers, e.g. guide vanes, baffles, perforated plates, etc. at strategic locations within the windbox.

• g) The purchaser shall approve the company and individuals providing the analyses. The purchaser shall be provided with the resumé of each of these individuals, including detailed information regarding his or her experience with CFD in similar arrangements.

A good CFD model can predict the temperature profiles throughout the furnace and near the burner's exit. This includes designs where supplemental combustibles are required and injected. The CFD model is more easily developed in retrofits where the temperature profiles and flue gas composition throughout the upstream combustion equipment and flue gas ducts can be measured. In new units, assistance may be provided by the OEM whom may have completed its own CFD model.

Cold flow modeling has been used to design burner windboxes, burner combustion air ducting, and flue gas ducts. Cold flow modeling simulates fluid flow and obtains useful design guidance. This modeling technique involves creating a hydraulically similar model of the plenum and simulating flow of fluid using smoke or colored fluid. Results obtained from the model are applied to actual conditions, based on experience. Quantitative data is provided by measurements made using a hot wire anemometer.

Cold flow modeling should meet these objectives:

a) geometric similarity,

b) dynamic similarity.

While carrying out cold flow model testing, the following points shall be considered.

a) A laboratory scale model shall be developed based on the actual general arrangement drawing of the furnace volume and burner windbox and air/flue gas mixing (when applicable).

b) The experimental model scale shall be determined based on the experience of the agency carrying out the modeling, client's preference, and the need for practical manipulation in the laboratory. Geometric scaling is typically 1:12 or 1:10.

c) The model shall include static gas mixing devices like guide vanes, baffles, perforated plates, etc., and structural members like trusses, beams, etc.

d) Models shall be constructed in transparent material, such as plexiglass, for visual clarity.

e) The model shall be constructed for easy modifications of static gas mixing devices.

f) Model may be operated using air at ambient temperature. Volume flow through the model shall be measured by a standard orifice meter or pitot tube. The flow velocity in the model shall be adjusted in such a way that the model Reynolds number in the duct and the reactor ensures similarity between the model scale and the full scale of equipment over the full operating range, inclusive of turndown.

g) Flow pattern may be investigated by using a smoke generator, cork dust injection, cotton tufts, etc. Flow visualization shall be documented properly by video recording.

h) The final report of the cold flow modeling shall include description, drawings, and photographs of the model and necessary flow conditioning devices required to achieve the desired flow and temperature distribution. Procedure, theory, and method used to correlate model velocity, and pressure measurements with respect to the full-scale system, should also be included.

For the burner windbox, mass flow readings to each burner, peripheral air distribution around each burner, and individual burner swirl should be recorded both with the initial tested configuration and with the final configuration.

Annex A
(informative)

Equipment Data Sheets [13]

A.1 Instructions for Use

These data sheets are designed to provide a concise, but thorough, definition of the boiler system and its performance. The data sheets should evolve throughout the course of a project. The level of detail reflected in the data sheets should be consistent with the current stage of the project. Early in a project, the sheets may contain less detail than later revisions. Some of the fields on these sheets may remain blank if the information is not known or not relevant to the particular application. Users of these data sheets are encouraged to apply reasonable judgment in determining which fields apply.

It is intended that these data sheets become the controlling document in specifying boiler equipment. Accordingly, all parties involved with the boiler, including vendors, engineering contractors, purchasers, and end users, shall share a clear understanding of the meaning of each field. While many of the fields are self-explanatory, some require clarification beyond the wording of the field labels. These instructions describe in more detail fields whose labels can be inadequate to fully define their purpose. In addition, to support the goal of defining the boiler system, it is often appropriate to append a process control diagram to the data sheets at the start of a boiler project.

Data sheets are divided into groups to facilitate use. These groups are:

— design data including site conditions and utilities;

— performance data;

— guarantee data;

— BFW analysis;

— boiler mechanical description, including tubes, headers, and drums;

— refractory and insulation;

— fans (FD and ID);

— duct work and stack;

— igniter/igniter supply system;

— main burner supply system for gas firing and oil firing;

— combustion controls;

— fuel analysis;

— burners/igniters;

[13] Users of this Annex should not rely exclusively on the information contained in this document. Sound business, scientific, engineering, and safety judgment should be used in employing the information contained herein. Where applicable, authorities having jurisdiction should be consulted.

— valves;

— transmitters, control panel, flow meters, analyzers, and drum instrumentation;

— local control panel schematic;

— typical customer connection points;

— instrument scope of supply.

These data sheets cover both mechanical and process aspects of boiler design.

All forms have a line in the header at the top that contains “Page ____ of ____.” The preparer of this form is strongly encouraged to include both page numbers and total pages on all forms. In the event that subsequent revisions result in additional pages, it is recommended to modify the page numbers by using 3A, 3B, etc. pages, as an example. This avoids having to renumber all pages.

It is to be expected that revisions will occur to the data sheets during the course of a project. All forms include one or more columns labeled “REVISIONS” where a revision can be marked. In addition, the heading section of each form contains a “revision number” field. When a set of changes is made to a set of data sheets, this set of changes is referred to as a revision and is assigned the next revision number. The original issue should be noted as revision zero (0). All changes made in a revision are marked with the same revision number.

Each revision REMARK should contain, as a minimum, the revision number, the revision date and a description of the revision such as “Revised per vendor quote” or “Revised for purchase.” Additional information, such as a list of affected forms/lines, can be useful for tracking purposes. Each revision should be issued as a complete set of pages, not as individual pages. This ensures that all recipients have a complete, current set of data sheets.

A.2 Water Tube Boiler Data Sheets

Page 248 through page 264 contain data sheets in SI Units, and page 265 through page 281 contain data sheets in USC Units for water tube boilers.

API 538 WATER TUBE BOILER DATA SHEET

(SI Units)

REVISIONS					
NUMBER	0	1	2	3	4
DATE					
ORIGINATOR					
REVIEWED					
APPROVED					

DOC. NUMBER

JOB NUMBER	PAGE 1	OF	17
PURCHASER			
LOCATION			
UNIT			
ITEM NUMBER			
SERVICE			
REQ NUMBER			

DESIGN, MANUFACTURE & TESTING SHALL CONFORM TO SPECIFICATION: ○ API RP-538 ○ Other			
INFORMATION TO BE COMPLETED: ○ BY PURCHASER □ BY MANUFACTURER ◙ BY PURCHASER OR MANUFACTURER			
Manufacturer	Model	Quantity	
DESIGN DATA			
○ Boiler Capacity:	Maximum Continuous Rating (MCR) (kg/h):	(standard practice)	
	2-Hour Peak (24 Hours Between Peaks) (kg/h):	(special design requirement)	
○ Steam at ○ Boiler ○ Superheater	Outlet: Pressure (kPag):	Temperature (ºC):	
○ Minimum Stable Load (kg/h):	○ Temperature Control Range (kg/h):		
○ Feedwater Temperature Entering:	Boiler (ºC):	Economizer (ºC):	
○ Feedwater Treatment:	Feedwater Analysis: see page 3 of 17		
○ Boiler Water Analysis:	Continuous Boiler Blowdown: (%) Design		
○ Steam Purity Required: TDS µg/L	Si µg/L	Cl µg/L	Na µg/L
○ Furnace Design:			
Maximum Heat Absorption Rate (kW/m²):	(Based on EPRS)	EPRS = Effective Projected Radiant Surface	
Maximum Heat Liberation Rate (kW/m³):			
○ Special Requirements:			
○ Type of Installation: ○ Indoor ○ Outdoor	○ Boiler Plot Limitations:		
Construction: ○ Shop assembled (packaged) ○ Field Erected	○ FD Fan Drive: ○ Electric Motor ○ Steam Turbine		
Provide: ○ Economizer ○ Air Heater ○ Air Htr (recuperative)	○ Dual Drivers; Motor and Turbine		
○ Flue Gas Duct to be Provided: ○ Yes ○ No	○ Dampers to be Provided: ○ No ○ Yes		
○ Minimum Stack Height above grade (m):	Location:		
Stack Supplied by: ○ Boiler Supplier ○ Other	○ Damper Operation: ○ Manual ○ Automatic		
SITE CONDITIONS			
○ Ambient Air: Design Temperature (ºC):	○ Relative Humidity (2% of year) (%):		
Minimum Temperature (ºC):	○ Maximum Temperature (ºC):		
○ Design Wind Load (kg/m²):	○ Design Snow Load (kg/m²):		
○ Earthquake Factor:	○ Elevation (above Sea Level) (m):		
○ Freezing Climate: ○ Yes ○ No			
UTILITIES			
○ Steam for Auxiliaries:			
Fan Turbine Throttle (kPag):	Maximum Pressure (kPag):	Minimum Temperature (ºC):	
Exhaust Pressure (kPag):	Exhaust Temperature (ºC):		
Sootblowers (from Plant Mains) (kPag):			
Atomizing Steam (kPag): (ºC):			
○ Electrical Power Supply:	Area Classification:		
Frequency [(Hz) 3-Phase]:			
Motors:	Through (kW):	Volts:	
	Over (kW):	Volts:	
Instruments (V):			
○ Cooling Water: Inlet: kPag @ ºC	Outlet: kPag @ ºC		
○ Condensate: kPag @ ºC for Desuperheater			
○ Plant Air (kPag)	Oil Free ○ Yes ○ No		
○ Instrument Air (kPag):	Dry and Oil Free ○ Yes ○ No	○ Dewpoint: ºC @ kPag	
Remarks:			

AMERICAN PETROLEUM INSTITUTE

API 538 WATER TUBE BOILER DATA SHEET

(SI Units)

REVISIONS					
NUMBER	0	1	2	3	4
DATE					
ORIGINATOR					
REVIEWED					
APPROVED					

DOC. NUMBER

JOB NUMBER	PAGE **2**	OF	**17**
PURCHASER			
LOCATION			
UNIT			
ITEM NUMBER			
SERVICE			
REQ NUMBER			

1	DESIGN, MANUFACTURE & TESTING SHALL CONFORM TO SPECIFICATION: ○ API RP-538 ○ Other						
2	INFORMATION TO BE COMPLETED: ○ BY PURCHASER ☐ BY MANUFACTURER ◎ BY PURCHASER OR MANUFACTURER						
3	Manufacturer		Model			Quantity	
4	**PERFORMANCE DATA**						
5	Operation	**Design**	Normal	Minimum	75% MCR	50% MCR	25% MCR
6	○ Steam Flow kg/h						
7	○ Name of fuel						
8	○ Blowdown %						
9	☐ Excess Air %						
10	☐ Maximum Heat Absorption Rate kW/m²						
11	☐ Maximum Heat Liberation Rate kW/m³						
12							
13	☐ **Quantity** kg/s						
14	Fuel Flow						
15	Flue Gas Leaving Boiler						
16	Air Flow Leaving FD Fan						
17	Flue Gas Recirculation Flow						
18	Steam Flow @ Superheater Outlet						
19	Desuperheater Spray Flow						
20	☐ **Temperature** ºC						
21	Final Steam Temperature						
22	Steam Leaving Superheater						
23	Flue Gas Leaving Boiler						
24	Flue Gas Leaving Economizer						
25	Water Leaving Economizer						
26	Water Entering Economizer						
27	☐ **Pressure** kPag						
28	Battery Limit (Steam outlet)						
29	Superheater Outlet						
30	Drum						
31	Economizer Inlet (Feedwater)						
32	☐ **Air Resistance** kPa						
33	Burners						
34	Ducts / Windbox						
35	Net Resistance						
36	☐ **Draft Losses** kPa						
37	Firebox						
38	Boiler & Superheater						
39	Economizer						
40	Flues / Stack						
41	Other						
42	Net Draft Loss						
43	☐ **% Heat Loss (by HHV)**						
44	Dry Gas						
45	Moisture in Fuel						
46	Unburned Combustible						
47	Radiation						
48	Manufacturer's Margin						
49	Total						
50	☐ **Net Efficiency** (by Higher Heating Value) %						
51	(by Lower Heating Value) %						
52	**Remarks:**						
53							
54							
55							

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GUARANTEED PERFORMANCE		
○ Fuel		FOR ALL IDENTIFIED OPERATING CASES.
○ Rated Capacity	kg/h	○ NOx:
○ Steam Temperature @ Terminal Point	ºC	○ SOx:
○ Steam Pressure @ Terminal Point	kPag	○ CO:
○ Thermal Efficiency	%	○ HC:
○ Boiler Control Range (Min steam flow @ design temp)	kg/h	○ Particulate:
○ Min Steam Flow @ Steam Temp. kg/h @	ºC	
○ FD Fan Static Pressure	kPa	○ Solids in Steam:
○ FD Fan Power (max.)	kW	○ % Dryness of Steam @ Drum Exit

GUARANTEE BASIS			
○ Feedwater Temperature	ºC	○ Fuels	
○ Ambient Temperature - Max Min	ºC	○ Higher Heating Value	○ Lower Heating Value
○ Altitude (above Sea Level)	m	○ Humidity (kg moisture / kg dry air)	
○ Blowdown (% Rated Capacity)			

BOILER FEEDWATER ANALYSIS				
○ pH @ 25 ºC			Total (mg/L)	Dissolved (mg/L)
○ P Alkalinity	mg/L $CaCO_3$	○ Calcium (Ca)		
○ M Alkalinity	mg/L $CaCO_3$	○ Magnesium (Mg)		
○ Conductivity	μS/cm (un-neutralized)	○ Sodium (Na)		
○ Total Dissolved Solids (TDS)	mg/L	○ Potassium (K)		
○ Total Suspended Solids (TSS)	mg/L	○ Iron (Fe)		
		○ Copper (Cu)		
○ Hydroxide (OH)	mg/L	○ Manganese (Mn)		
○ Carbonate (CO_3)	mg/L	○ Aluminum (Al)		
○ Bicarbonate (HCO_3)	mg/L	○ Zinc (Zn)		
○ Total Silica (SiO_2)	mg/L	○ Nickel (Ni)		
○ Chloride (Cl)	mg/L	○ Chromium (CrO_4)		
○ Sulfate (SO_4)	mg/L	○ Carbon Dioxide (CO_2)		
○ Ortho Phosphate (PO_4)	mg/L	○ Organics		

Weights				**Dimensions** (preliminary)		
kg	Boiler	Economizer	Stack		**Overall Boiler**	**Overall Plot Space**
☐ Shipping				Length (m):		
☐ Operating				Width (m):		
☐ Full of Water				Height (m):		

☐ Steam Drum shipping weight: kg
(when supplied as a separate item)

Remarks:

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BOILER			
Manufacturer:		Type:	
Design Code:		No. of Boilers:	
Maximum Continuous Rating:	kg/h	Peak Rating: (special)	kg/h
Superheater Outlet Pressure:	kPag	Temperature: ºC	(Downstream of NRV)
Feedwater Pressure required at:	Economizer (kPag):	Control Station (kPag):	

Construction Details

Firebox	Tube OD (mm)	Tube Thickness (mm)	Tube Pitch (mm)	Corr Allow (mm)	Tube Material
Side Walls					
Division Walls					
Roof					
Floor					
Rear Wall					
Front Wall					

Firebox Volume (m³):		Projected Heating Surface Based on EPRS (m²):
Furnace Length (m):	Width (m):	Height (m):

Superheater Screen

Arrangement:	☐ Staggered	☐ In-Line	☐ Single Row	☐ None
Tube:	OD (mm):	Thickness (mm):	Corr Allow (mm)	Material:
No. of Tubes Wide:	Pitch (mm):	Gas Space: Width (m):	Height (m):	
No. of Rows Deep:	Pitch (mm):	Gas Velocity (m/s):	Mass Flow (kg/h):	
Effective Heating Surface (m²):		Effective Tube Length (m):		

Superheater

Type:	☐ Drainable	☐ Non-drainable	☐ Radiant Convection	☐ Convection		
Arrangement:	☐ Staggered	☐ In-Line	☐ U-Tube	☐ Pendant	☐ Horizontal	☐ Vertical

Primary Superheater

No. of Tubes Wide:	Pitch (mm):	No. of Steam Passes:	Gas Space: Width (m):	Height (m):	
No. of Rows Deep:	Pitch (mm):	No. of Gas Passes:	Gas Velocity (m/s):	Mass Flow (kg/h):	
Tubes:	OD (mm):	Thickness (mm):	Material:	No. of Rows:	
	OD (mm):	Thickness (mm):	Material:	No. of Rows:	
	OD (mm):	Thickness (mm):	Material:	No. of Rows:	
	Corrosion Allowance (mm):				
Effective Heating Surface (m²):			Effective Tube Length (m):		
Metal Temperature (ºC):	Design (ºC):	Max. (ºC) (First Row):	Max. (ºC) (Last Row):		

Secondary Superheater

No. of Tubes Wide:	Pitch (mm):	No. of Steam Passes:	Gas Space: Width (m):	Height (m):	
No. of Rows Deep:	Pitch (mm):	No. of Gas Passes:	Gas Velocity (m/s):	Mass Flow (kg/h):	
Tubes:	OD (mm):	Thickness (mm):	Material:	No. of Rows:	
	OD (mm):	Thickness (mm):	Material:	No. of Rows:	
	OD (mm):	Thickness (mm):	Material:	No. of Rows:	
	Corrosion Allowance (mm):				
Effective Heating Surface (m²):			Effective Tube Length (m):		
Metal Temperature (ºC):	Design (ºC):	Max. (ºC) (First Row):	Max. (ºC) (Last Row):		

Intermediate Screen

Arrangement:	☐ Staggered	☐ In-Line	☐ Single Row	☐ None
Tube:	OD (mm):	Thickness (mm):	Corr Allow (mm)	Material:
No. of Tubes Wide:	Pitch (mm):	Gas Space: Width (m):	Height (m):	
No. of Rows Deep:	Pitch (mm):	Gas Velocity (m/s):	Mass Flow (kg/h):	
Effective Heating Surface (m²):		Effective Tube Length (m):		

Remarks:

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1	☐ **Boiler Bank (Evaporator Section)**					
2	Arrangement:	☐ Staggered	☐ In-Line			
3	Tube:	OD (mm):	Thickness (mm):	Corr Allow (mm)	Material:	
4	No. of Tubes Wide:	Pitch (mm):	Gas Space: Width (m):	Height (m):		
5	No. of Rows Deep:	Pitch (mm):	Gas Velocity (m/s):	Mass Flow (kg/h):		
6	Effective Heating Surface (m²):	Effective Tube Length (m):				
7						
8	☐ **Economizer**					
9	Manufacturer:	Type:	☐ Bare Tube	☐ Finned	Fin Type: ☐ Solid	☐ Segmented
10	Arrangement:	☐ Staggered	☐ In-Line	Mounting (tube orientation)	☐ Horizontal	☐ Vertical
11	Tube:	OD (mm):	Thickness (mm):	Corr Allow (mm)	Material:	
12	Fins:	Height (mm):	Thickness (mm):	Spacing (# fins/mm):	Material:	
13	No. of Tubes Wide:	Pitch (mm):	Gas Space: Width (m):	Height (m):		
14	No. of Rows Deep:	Pitch (mm):	Gas Velocity (m/s):	Mass Flow (kg/h):		
15	Effective Heating Surface (m²):	Effective Tube Length (m):				
16	No. of Water Passes:	No. of Gas Passes:	Min. Tube Metal Temp (ºC):			
17						
18	☐ **Air Heater**					
19	Manufacturer:	Type (Recuperative):				
20	Arrangement:	☐ Staggered	☐ In-Line	☐ Horizontal	☐ Vertical	
21	Air:	☐ Inside Tubes	☐ Outside Tubes			
22	Tube:	OD (mm):	Thickness (mm):	Corr Allow (mm)	Material:	
23	No. of Tubes Wide:	Pitch (mm):	No. of Air Passes:			
24	No. of Rows Deep:	Pitch (mm):	No. of Gas Passes:			
25	Effective Heating Surface (m²):	Effective Tube Length (m):				
26	Minimum Calculated Tube Material Temperature (ºC):	Corrosion Prevention Feature:				
27						
28	☐ **Steam Drum**					
29	Design Pressure (kPag):	Design Temperature (ºC):	ID (mm):	Straight Length (m):		
30	Tube Plate Thickness (mm):	Wrapper Plate Thickness (mm):	Material:			
31	Type of Heads:	ID (mm):	Thickness (mm):	Material:		
32	Manholes:	No.	Size:	Lengths Between Welds (m):		
33	Tube Connection:	☐ Welded	☐ Expanded	☐ Both	Ligament Efficiency:	
34	Normal Water Level (NWL):	Below Drum Centerline (mm):	Above Drum Centerline (mm):			
35	High Water Level:	(mm) Above NWL:	Low Water Level:	(mm) Below NWL:		
36	Water Level Cutoff:	(mm) Below NWL (Low):	(mm) Above NWL (High):			
37	Drum Volume:	m³ (Below NWL):	m³ (Between LLA and LLCO):			
38	Steam Drum Retention Time (minutes):	(between Normal Water Level (NWL) and Low Low Trip (LLT))				
39						
40						
41	**Steam Drum Internals**					
42	Brief Description:					
43						
44	Separators:	Qty:	Type:	Manufacturer:	Model No.	
45	Dryers	Qty:	Type:	Manufacturer:	Model No.	
46						
47	**Water (lower) Drum**					
48	Design Pressure (kPag):	Design Temperature (ºC):	ID (mm):	Straight Length (m):		
49	Tube Plate Thickness (mm):	Material:				
50	Type of Heads:	ID (mm):	Thickness (mm):	Material:		
51	Manholes:	No.	Size:	Lengths Between Welds (m):		
52	Tube Connection:	☐ Welded	☐ Expanded	☐ Both	Ligament Efficiency:	
53	Volume of Water Drum (m³)	Total Internal Volume of Tubes (m³):				
54	Vertical Distance Between Steam and Water Drums (m):					
55						

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Wall Headers

Location:			Design Pressure (kPag):		Corr Allow (mm)
OD (mm):	Thickness (mm):	Material:	Tube Connection: ☐ Welded	☐ Expanded	☐ Both
Supplies No.:	OD (mm):	Thickness (mm):	Material:		
Risers No.:	OD (mm):	Thickness (mm):	Material:		
Location:			Design Pressure (kPag):		Corr Allow (mm)
OD (mm):	Thickness (mm):	Material:	Tube Connection: ☐ Welded	☐ Expanded	☐ Both
Supplies No.:	OD (mm):	Thickness (mm):	Material:		
Risers No.:	OD (mm):	Thickness (mm):	Material:		
Location:			Design Pressure (kPag):		Corr Allow (mm)
OD (mm):	Thickness (mm):	Material:	Tube Connection: ☐ Welded	☐ Expanded	☐ Both
Supplies No.:	OD (mm):	Thickness (mm):	Material:		
Risers No.:	OD (mm):	Thickness (mm):	Material:		
Location:			Design Pressure (kPag):		Corr Allow (mm)
OD (mm):	Thickness (mm):	Material:	Tube Connection: ☐ Welded	☐ Expanded	☐ Both
Supplies No.:	OD (mm):	Thickness (mm):	Material:		
Risers No.:	OD (mm):	Thickness (mm):	Material:		

Primary Superheater Headers

Inlet	OD (mm):	Thickness (mm):	Material:	
Outlet	OD (mm):	Thickness (mm):	Material:	
Tube Connection:	☐ Welded	☐ Expanded	☐ Both	Corr Allow (mm)
Saturated Connections No.:	OD (mm):	Thickness (mm):	Material:	

Secondary Superheater Headers

Inlet	OD (mm):	Thickness (mm):	Material:	
Outlet	OD (mm):	Thickness (mm):	Material:	
Tube Connection:	☐ Welded	☐ Expanded	☐ Both	Corr Allow (mm)

Economizer Headers

Inlet	OD (mm):	Thickness (mm):	Material:	
Outlet	OD (mm):	Thickness (mm):	Material:	
Tube Connection:	☐ Welded	☐ Expanded	☐ Both	Corr Allow (mm)
Connection to Drum No.:	OD (mm):	Thickness (mm):	Material:	

☐Attemperator / Desuperheater

No. Required:	Manufacturer:		Type:	☐ Non-contact	☐ Spray
☐ Design Flow (steam)		kg/h	Location	☐ Interstage	☐ Superheater outlet
☐ Design Flow (water)		kg/h	○ Spray Water Temperature		°C
○ Spray Water Source			○ Spray Water Pressure		kPag

Access Requirements (Platforms / Ladders / Stairs)

Furnished by ○ Purchaser ○ Supplier ○ Material ○ Loading kg/m²

Typical Locations:	Platform	Ladder	Stairs		Platform	Ladder	Stairs
Boiler Front (Burner decks)	x		x	Economizer	caged	x	
FD Fan and driver	x	x		Stack	x	caged	
Steam Drum (Heads & PRV's)	x	x	x	Inspection ports	x	x	
Lower Drum (Manways)	x	x		Access Hatches	x	x	

Remarks:

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Refractory and Insulation			
○ Design Basis: Ambient Temperature ºC	Wind Velocity (km/h)	Casing Temperature ºC	
☐ **Exposed Vertical Walls**			
Lining Thickness (mm):	Hot-face Temperature (ºC):	Design:	Calculated:
Wall Construction:			
Anchor (material and type)			
Casing material	Thickness (mm):	Temperature (ºC):	
☐ **Shielded Vertical Walls**			
Lining Thickness (mm):	Hot-face Temperature (ºC):	Design:	Calculated:
Wall Construction:			
Anchor (material and type)			
Casing material	Thickness (mm):	Temperature (ºC):	
☐ **Burner Throat**			
Lining Thickness (mm):	Hot-face Temperature (ºC):	Design:	Calculated:
Wall Construction:			
Anchor (material and type)			
Casing material	Thickness (mm):	Temperature (ºC):	
☐ **Floor**			
Lining Thickness (mm):	Hot-face Temperature (ºC):	Design:	Calculated:
Wall Construction:			
Anchor (material and type)			
Casing material	Thickness (mm):	Temperature (ºC):	
Minimum Floor Elevation (mm):	Free Space below Tubes (mm):		
☐ **Convection Section**			
Lining Thickness (mm):	Hot-face Temperature (ºC):	Design:	Calculated:
Wall Construction:			
Anchor (material and type)			
Casing material	Thickness (mm):	Temperature (ºC):	

☐ **Ducts:**	**Combustion Air**		**Flue Gas**		
Location					
Size or net free area (m²)					
Casing material					
Casing Thickness (mm):					
Lining: Internal / external					
Thickness (mm):					
Material					
Anchor (material and type)					
Casing temperature (ºC):					

☐**Windbox**			
Casing material	Thickness (mm):	Size (mm):	
Lining material	Thickness (mm):	Design:	Calculated:
Anchor (material and type)			
Remarks:			

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FORCED DRAFT FAN						**INDUCED DRAFT FAN**				
No. Required:	Manufacturer:					No. Required:	Manufacturer:			
Type:						Type:				
Speed (rpm):		Impeller Diameter (mm):				Speed (rpm):		Impeller Diameter (mm):		
Flow Control Device:						Flow Control Device:				
Air Flow	Oil: dm³/s	°C	kPa	kW		Gas Flow	Oil: dm³/s	°C	kPa	kW
at MCR:	Gas: dm³/s	°C	kPa	kW		at MCR:	Gas: dm³/s	°C	kPa	kW
Test Block:	dm³/s	°C	kPa	kW		Test Block:	dm³/s	°C	kPa	kW
Fan Sound Level:	(dBA) at	m from Fan				Fan Sound Level:	(dBA) at	m from Fan		
Detailed information shown on separate Fan data sheet.						Detailed information shown on separate Fan data sheet.				

Motor Driver:	Manufacturer:	Type	kW:
	Motor Sound Level: (dBA) at m from Motor		
Steam Turbine Driver:	Manufacturer:	Type	
	Water Rate: kg/kW/h	Horsepower:	
	Exhaust Steam Temperature (°C):	Governor: ☐ Mechanical ☐ Hydraulic	
	Turbine Sound Level: (dBA) at m from Turbine		

Air Ducts

FD Fan Suction:	Size (m):	Thickness (mm):	Corr Allow (mm)	Material:
FD Fan to Windbox:	Size (m):	Thickness (mm):	Corr Allow (mm)	Material:
(Air Heater)	Venturi Included: ◯ Yes ◯ No			
	Damper Included: ◯ Yes ◯ No		Damper: ◯ Single vane	◯ Multivane
	Expansion Joints:	No.:	Location:	Type:
	Maximum Design Temperature (°C):		Manufacturer:	
	Supports Included: ◯ Yes ◯ No		Max. Air Velocity (m/s):	
Air Htr to Windbox	Size (m):	Thickness (mm):	Corr Allow (mm)	Material:
	Expansion Joints:	No.:	Location:	Type:
	Maximum Design Temperature (°C):		Manufacturer:	
	Supports Included: ◯ Yes ◯ No		Max. Air Velocity (m/s):	

Flue Gas Ducting

Boiler to:	Size (m):	Thickness (mm):	Corr Allow (mm)	Material:
◯ Economizer	Expansion Joints:	No.:	Location:	Type:
◯ Air Heater	Maximum Design Temperature (°C):		Manufacturer:	
	Supports Included: ◯ Yes ◯ No		Max. Gas Velocity (m/s):	
◯ Boiler	Size (m):	Thickness (mm):	Corr Allow (mm)	Material:
◯ Economizer	Damper Included: ◯ Yes ◯ No		Damper: ◯ Single vane	◯ Multivane
◯ Air Heater	Expansion Joints:	No.:	Location:	Type:
TO:	Maximum Design Temperature (°C):		Manufacturer:	
◯ Main Flue	Supports Included: ◯ Yes ◯ No		Max. Gas Velocity (m/s):	
◯ Stack				
Main Duct	Size (m):	Thickness (mm):	Corr Allow (mm)	Material:
	Terminal Point:			
	Damper Included: ◯ Yes ◯ No		Damper: ◯ Single vane	◯ Multivane
	Expansion Joints:	No.:	Location:	Type:
	Maximum Design Temperature (°C):		Manufacturer:	
	Isolating Blind included: ◯ Yes ◯ No		Max. Gas Velocity (m/s):	

Stack

Furnished by ◯ Supplier ◯ Purchaser	Height (m):	Type ◯ Self-Supporting	◯ Supported
Inside diameter (m): Base:	Top: Thickness (mm):	Corr Allow (mm)	Material:
Max. Gas Velocity (m/s):	Lining: Thickness (mm):	Material:	
◯ FAA Lighting Required	◯ Caged Ladder to Test Platform	◯ Personnel Protection Screen	
◯ CEMS Ports	◯ Access Door	◯ Vibration Isolation	

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BURNERS

	Number	Type	Manufacturer	Model	Turndown	Heat Input / Burner	Atom. Steam or Air
○ Gas							
○ Oil							
○ Igniter							

☐ Flame Scanner: Number: Manufacturer / Model: Type:

IGNITER / IGNITER SUPPLY SYSTEM

Furnished by: ○ Supplier ○ Purchaser | ☐ Rated Capacity W

○ Class I ○ Class II ○ Class III

Auto Retraction of Spark Device: ○ Yes ○ No

	Manufacturer	Size
Auto Vent Valve		
Auto Shutoff Valve		
Manual Shutoff Valve		

	Manufacturer	Model
Press. Ind. (w / S.O. Valves)		
Hi/Lo Pressure Switch		
Pressure Regulator		
Drip Leg		

MAIN BURNER SUPPLY SYSTEM (GAS FIRING)

Furnished by ○ Supplier ○ Purchaser | ☐ Rated Capacity W

○ Burner Type

	Manufacturer	Size
Auto Vent Valve		
Auto Shutoff Valve		
Manual Shutoff Valve		
Vent Leak Valve		
Gas Flow Control Valve		

	Manufacturer	Model
Pressure Regulator		
Gas Strainer		
Hi/Lo Pressure Switch		
Press. Ind. (w / S.O. Valves)		
Drain Valve		

MAIN BURNER SUPPLY SYSTEM (OIL FIRING)

Furnished by ○ Supplier ○ Purchaser | ☐ Rated Capacity W

○ Burner Type

	Manufacturer	Size
Recirculation Valve		
Auto Shutoff Valve		
Manual Shutoff Valve		
Vent Leak Valve		
Oil Flow Control Valve		

	Manufacturer	Model
Low Pressure Switch		
Oil Strainer		
Check Valve		
Press. Ind. (w / S.O. Valves)		
Drain Valve		

ATOMIZING AIR / STEAM (OIL FIRING ONLY)

Furnished by ○ Supplier ○ Purchaser | ☐ Rated Capacity kg/h

	Manufacturer	Size
Auto Shutoff Valve		
Manual Shutoff Valve		
Control Valve		
Check Valve		
Strainer		

	Manufacturer	Model
Low Pressure Switch		
Press. Ind. (w / S.O. Valves)		
Drain w/ Trap		

COMBUSTION CONTROLS AND BURNER MANAGEMENT

○ Burner Management System

○ Combustion Controls

○ Control Type

○ Panel Enclosure:

Power Supplies	Voltage	Phase	Hertz
○ Instrument / Control Power			
○ Control Panel Power			

Remarks:

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FUEL ANALYSIS								
FUEL GAS			IGNITER GAS			LIQUID		
Composition by:			Composition by:					
◯ Mole % ◯ Volume % ◯ Weight %			◯ Mole % ◯ Volume % ◯ Weight %					
	Design	**Range**		**Design**	**Range**		**Design**	**Range**
Fuel			Fuel			Ultimate Analysis	(Weight Percent)	
Hydrogen Sulfide (H_2S)			Hydrogen Sulfide (H_2S)			Carbon		
Hydrogen (H_2)			Hydrogen (H_2)			Hydrogen		
Nitrogen (N_2)			Nitrogen (N_2)			Oxygen		
Carbon dioxide (CO_2)			Carbon dioxide (CO_2)			Nitrogen		
Methane (CH_4)			Methane (CH_4)			Sulfur		
Ethane (C_2H_6)			Ethane (C_2H_6)			Ash		
Ethylene (C_2H_4)			Ethylene (C_2H_4)			Moisture		
Propane (C_3H_8)			Propane (C_3H_8)			**Total**	100	
Propylene (C_3H_6)			Propylene (C_3H_6)					
Isobutane (C_4H_{10})			Isobutane (C_4H_{10})			Flash Point (ºC):		
Butylene (C_4H_8)			Butylene (C_4H_8)			Density (kg/m³):		
N-Butane (C_4H_{10})			N-Butane (C_4H_{10})			Viscosity (dyna) (cP):		
Isopentane (C_5H_{12})			Isopentane (C_5H_{12})			Viscosity (kine) (cSt):		
Pentane (C_5H_{12})			Pentane (C_5H_{12})			Total H_2: (wt%)		
Hexane (C_6+)			Hexane (C_6+)			Ash Fusion Temp (ºC):		
Oxygen (O_2)			Oxygen (O_2)			Sodium (mg/kg):		
Carbon Monoxide (CO)			Carbon Monoxide (CO)			Vanadium (mg/kg):		
Total			**Total**			Nickel (mg/kg):		
Heating Values			Heating Values			Heating Values		
Higher (kJ/kg)			Higher (kJ/kg)			Higher (kJ/kg)		
Lower (kJ/kg)			Lower (kJ/kg)			Lower (kJ/kg)		
Higher (kJ/m³)			Higher (kJ/m³)					
Lower (kJ/m³)			Lower (kJ/m³)					
Mole Weight			Mole Weight					
Design Temp. ºC			Design Temp. ºC			Design Temp. ºC		
Header Pressure: (max) kPag			Header Pressure: (max) kPag			Header Pressure: (max) kPag		
Header Pressure: (min) kPag			Header Pressure: (min) kPag			Header Pressure: (min) kPag		

FUEL RATES						
Case Number	Design Case	Normal	Minimum	75%	50%	25%
Primary Gas kg/h						

Remarks:

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BURNERS / PILOTS

FUEL	◯ Liquid	◯ Gas	◯ Dual	NFPA fuel train by	◯ Supplier	◯ Purchaser
◯ Liquid Pressure at Inlet			kPag	Firing	☐ Single Wall	☐ Opposed Wall
◯ Gas Pressure at Inlet			kPag		☐ Tangential	☐ Other

FLAME SCANNERS

◯ Single ◯ Dual ◯ Number per Burner

Sensor Type ◯ Infrared ◯ Ultraviolet

BURNERS / PILOTS	Fuel Gas	Waste Gas	Fuel Oil	Waste Oil	Other
☐ Type					
☐ Manufacturer					
☐ Model					
☐ Number Required					
☐ Number Burners / Level					
☐ Number of Levels					
☐ Turndown					
☐ Heat Input / Burner					
☐ Fuel Consumption / Burner					
☐ Qty. Atomizing Steam / Air					
☐ Excess Air %					
☐ Pilot Fuel					
BURNER DETAILS					
☐ Dimensions					
☐ Pull Out Length					
☐					

SOOTBLOWERS

	Manufacturer	Model	Type	Quant	Consumption	Oper Press	Oper Temp
					kg/h	kPag	ºC
☐ Firebox							
☐ Convection Pass							
☐ Secondary S.H.							
☐ Primary S.H.							
☐ Economizer							
☐ Air Preheater							
☐							

◯ Automatic Sequencing Required Piping by ◯ Supplier ◯ Purchaser ◯ includes Steam Admission Valve

Media ◯ High Pressure Steam ◯ Medium Pressure Steam ◯ Compressed Air ◯ Plant Air

Additional Equipment by Supplier ◯ PLC Control Panel, Local PB stations (each unit)

◯ Relief Valve ◯ Pressure Transmitter ◯ Thermal Drain Valves

Remarks:

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BOILER VALVE SUMMARY

DESCRIPTION	**D = Double Valves**	Number Required	Size mm	End Type	Rating	Operator Type	Remarks
Boiler safety valve							
Boiler safety valve							
Superheater safety valve							
Main steam non-return valve							
Main steam stop valve							
Main steam stop bypass valve							
Main steam drain valve							
Main steam stop bypass drain valve							
Feedwater control valve							
Feedwater control valve isolation valve (inlet)							
Feedwater control valve isolation valve (outlet)							
Feedwater control valve bypass valve							
Feedwater control valve drain valves							
Boiler feed stop valve							
Boiler feed check valve							
Boiler vent valve							
Feedwater sample valves	**D**						
Steam gauge shut-off valve							
Steam gauge drain valve	**D**						
Water column & tie bar isolation valves							
Water column & tie bar drain valves	**D**						
Water column vent valves							
Gauge glass drain valves	**D**						
Desuperheater control valve							
Intermittent blowdown valves	**D**						
Waterwall lower header blow off valves	**D**						
Boiler drain valves							
Chemical feed shut-off valve							
Chemical feed check valve							
Continuous blowdown shut-off valve							
Continuous blowdown needle valve							
Saturated steam sampling shut-off valves							
Superheater vent valves	**D**						
Superheater start-up vent valves	**D**						
Superheater drain valves	**D**						
Spray water control valve isolation valves							
Spray water control valve bypass valve							
Spray water control valve drain valves							
Desuperheater spray water shut-off valve							
Desuperheater spray water check valve							
Spray water header drain valve							
Sample cooler water inlet valve							
Economizer vent valve							
Economizer drain valves	**D**						
Economizer bypass valve							(not normally required)
Economizer safety valve							(not normally required)
Level transmitter shut-off valves							

Remarks:

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TRANSMITTERS

○ Electronic ○ "Smart" Type

Service	Supplied by: Supplier	Supplied by: Purchaser	Shop Installed	Redundancy Required
Feedwater Pressure	○	○	☐	○
Drum Pressure	○	○	☐	○
Fuel Pressure	○	○	☐	○
Steam Pressure	○	○	☐	○
Furnace Pressure	○	○	☐	○
Windbox Pressure	○	○	☐	○
Boiler Outlet Pressure	○	○	☐	○
Economizer Outlet Pressure	○	○	☐	○
Feedwater Flow	○	○	☐	○
Fuel Flow	○	○	☐	○
Steam Flow	○	○	☐	○
Air Flow	○	○	☐	○
Drum Level	○	○	☐	○
Aux Low Water Cutout	○	○	☐	○
Steam Temperature	○	○	☐	○
Furnace Temperature	○	○	☐	○
Econ Inlet Gas Temp	○	○	☐	○
Econ Outlet Gas Temp	○	○	☐	○

Drum level instruments to be mounted on bridles: ○ Yes ○ No

CONTROL PANEL

Enclosure ○ NEMA 4X ○ Other

Area Classification ○ Unclassified

○ Class ○ Group ○ Div

PLC by ○ Supplier ○ Purchaser

PLC Manufacturer:

PLC includes:

○ Processor

○ Register Pack

○ Data Highway Module

○ Memory: Capacity =

○ I/O: Minimum pairs each

FLOW METERS

Air Flow	Fuel Flow
☐ Manufacturer	☐ Manufacturer
☐ Model	☐ Model
☐ Type	☐ Type
☐ Range	☐ Range

Steam Flow	Feedwater Flow
☐ Manufacturer	☐ Manufacturer
☐ Model	☐ Model
☐ Type	☐ Type
☐ Range	☐ Range

DCS SIGNALS (required for Purchaser)

Input Signals to DCS

○ Boiler Trip

○ Common Trouble Alarm

Steam: ○ Pressure ○ Temperature ○ Flow

Steam Drum: ○ Pressure ○ Level

○ Fuel Pressure

○ Economizer Outlet Flue Gas Temperature

Output Signals from DCS

○ Steam Pressure

○ Fuel Flow

○ Feedwater Flow

○ Fuel / Air Ratio Control

ANALYZERS

Analyzers by ○ Supplier ○ Purchaser

Oxygen Analyzer	NOx Analyzer
☐ Manufacturer	☐ Manufacturer
☐ Model	☐ Model
☐ Range	☐ Range

DRUM INSTRUMENTATION

	Type	Manufacturer	Range
☐ Water Column			
☐ Level Gauges			
☐ Press. Gauges			
☐ Temp. Guages			

RELIEF VALVES AND SILENCERS

Drum Relief Valve #1	Superheater Relief Valve
☐ Manufacturer	☐ Manufacturer
☐ Model	☐ Model
☐ Set Point kPag	☐ Set Point kPag

Drum Relief Valve #2	**Silencer - Superheater Vent (start-up)**
☐ Manufacturer	☐ Manufacturer
☐ Model	☐ Model
☐ Set Point kPag	☐ Noise Level dBA

Remarks:

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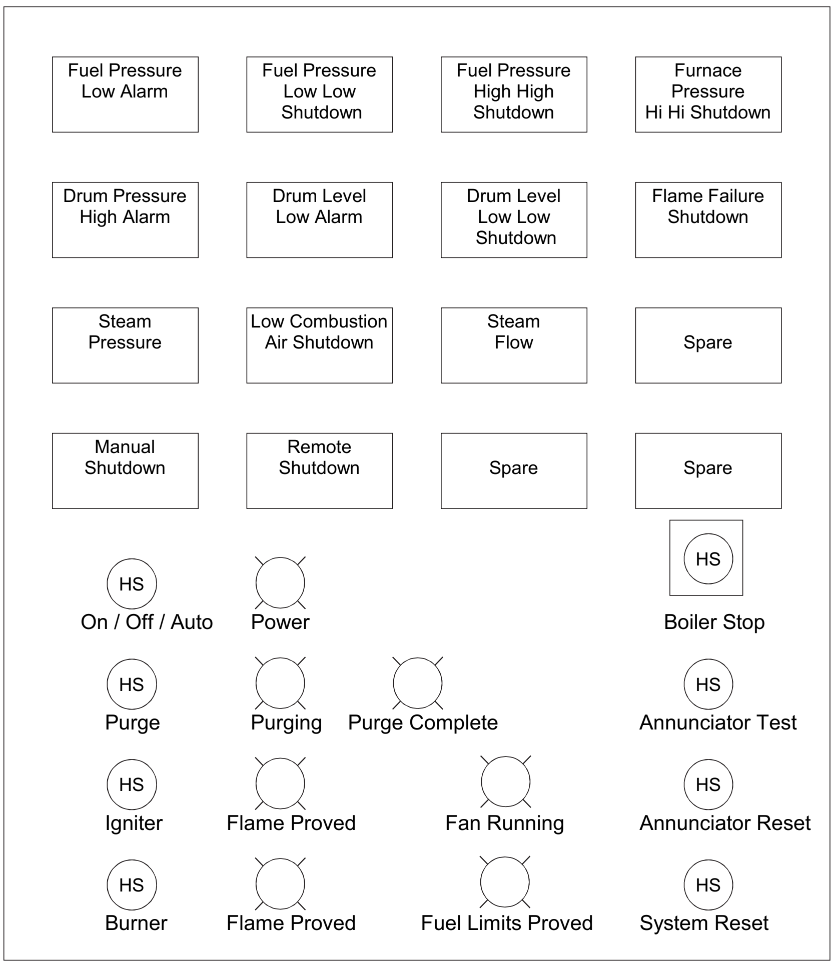
LOCAL CONTROL PANEL



☐ Panel Dimensions: ______ W x ______ L x ______ H   Access Door: ○ Front ○ Rear

Remarks: Annunciator windows to be a minimum of:

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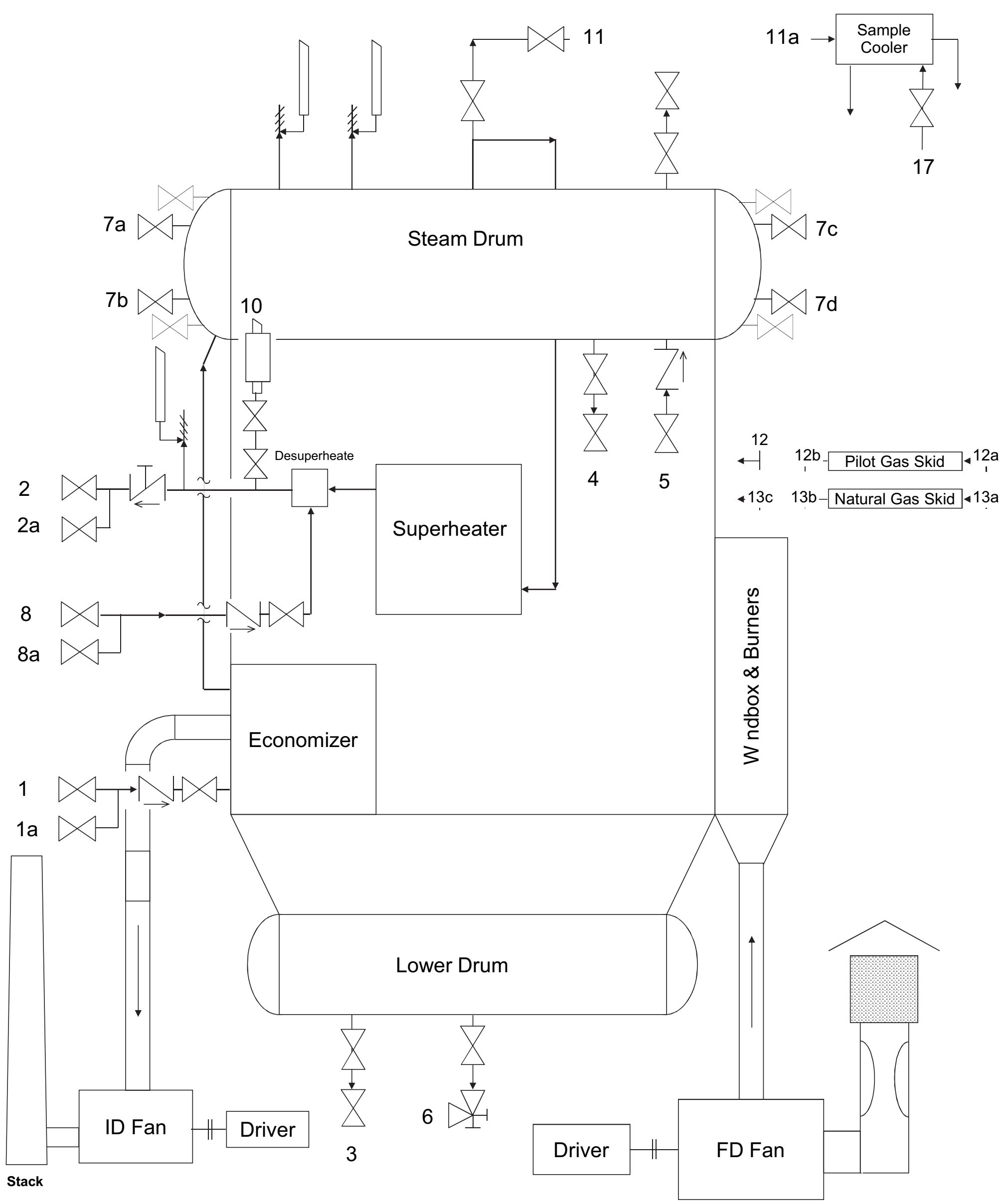
TYPICAL CUSTOMER CONNECTION



NOTE This sketch does not show all the various connections required for vents, drains, and instrument air.

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TYPICAL CUSTOMER CONNECTION SUMMARY

#	DESCRIPTION	Size (mm)	End Type	Rating Schedule	Flange Face	Weld Prep	Remarks
1	Feedwater Inlet						
2	Steam Outlet						
3	Intermittent Blowdown						
4	Continuous Blowdown						
5	Chemical Injection						
6	Economizer Drain						
7(a-d)	Level Transmitters						
8	Desuperheater Water Inlet						
9	Drum Vent						
10	Start-up Vent Outlet						
11	Saturated Steam Sample						
12a	Pilot Gas Inlet (Fuel Skid)						
12b	Pilot Gas Outlet (Fuel Skid)						
12c	Pilot Gas Inlet (to Burner)						
13a	Natural Gas Inlet (Fuel Skid)						
13b	Natural Gas Outlet (Fuel Skid)						
13c	Natural Gas Inlet (to Burner)						

REMARKS:

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INSTRUMENT SCOPE OF SUPPLY

DESCRIPTION	Element														Indication								Control by		
	Provided by				Type			Location			Installed by				Provided by				Location						
Instrument connection requirements to be established later.	Number of Units	Supplier	Purchaser		Direct Readout	Transmitter		Supplier Package	Purchaser Piping		Supplier		Purchaser		Supplier		Purchaser		@ Element	Local Panel	DCS	Local Panel + DCS	Local Panel	DCS	
Pressure Instruments																									
Drum Pressure																									
Superheater Outlet Pressure																									
Fuel Pressure																									
Furnace Pressure																									
Windbox Pressure																									
Temperature Instruments																									
TW / TE (Economizer IN/OUT)																									
TW / TE (Desuperheater IN/OUT)																									
TE (Superheater Surface)																									
Level Instruments																									
Water Columns (steam drum)																									
Bi-color ported gauge glass																									
with shut-off valves, illuminator, and viewing hood																									
Electrode type level monitor																									
with low level trip contact, relay with enclosure,																									
and blowdown holding switch																									
Fiber Optic Column																									
with fiber optic hardware, local detection unit in																									
a NEMA 4X cabinet with window for bicolor 12 point																									
display panel																									
Flow Instruments																									
Feedwater																									
Main Steam																									
Natural Gas																									
Air Flow																									
Miscellaneous Instruments																									
Pressure Relief Valve (steam drum)																									
Pressure Relief Valve (main steam)																									

Remarks:

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1	DESIGN, MANUFACTURE & TESTING SHALL CONFORM TO SPECIFICATION: ○ API RP-538 ○ Other			
2	INFORMATION TO BE COMPLETED: ○ BY PURCHASER ☐ BY MANUFACTURER ◙ BY PURCHASER OR MANUFACTURER			
3	Manufacturer	Model	Quantity	
4	**DESIGN DATA**			
5	○ Boiler Capacity:	Maximum Continuous Rating (MCR) (lb/h):	(standard practice)	
6		2-Hour Peak (24 Hours Between Peaks) (lb/h):	(special design requirement)	
7	○ Steam at ○ Boiler ○ Superheater	Outlet: Pressure (psig):	Temperature (ºF):	
8	○ Minimum Stable Load (lb/h):	○ Temperature Control Range (lb/h):		
9	○ Feedwater Temperature Entering:	Boiler (ºF):	Economizer (ºF):	
10	○ Feedwater Treatment:	Feedwater Analysis: see page 3 of 17		
11	○ Boiler Water Analysis:	Continuous Boiler Blowdown: (%) Design		
12	○ Steam Purity Required:	TDS ppb	Si ppb	Cl ppb / Na ppb
13	○ Furnace Design:			
14	Maximum Heat Absorption Rate (Btu/h-ft²):	(Based on EPRS)	EPRS = Effective Projected Radiant Surface	
15	Maximum Heat Liberation Rate (Btu/h-ft³):			
16	○ Special Requirements:			
17				
18				
19	○ Type of Installation: ○ Indoor ○ Outdoor	○ Boiler Plot Limitations:		
20	Construction: ○ Shop Assembled (Packaged) ○ Field Erected	○ FD Fan Drive: ○ Electric Motor ○ Steam Turbine		
21	Provide: ○ Economizer ○ Air Heater ○ Air Htr (Recuperative)	○ Dual Drivers; Motor and Turbine		
22	○ Flue Gas Duct to be Provided: ○ Yes ○ No	○ Dampers to be Provided: ○ No ○ Yes		
23	○ Minimum Stack Height Above Grade (ft):	Location:		
24	Stack Supplied by: ○ Boiler Supplier ○ Other	○ Damper Operation: ○ Manual ○ Automatic		
25				
26	**SITE CONDITIONS**			
27	○ Ambient Air: Design Temperature (ºF):	○ Relative Humidity (2% of year) (%):		
28	Minimum Temperature (ºF):	○ Maximum Temperature (ºF):		
29	○ Design Wind Load (lb/ft²):	○ Design Snow Load (lb/ft²):		
30	○ Earthquake Factor:	○ Elevation (Above Sea Level) (ft):		
31	○ Freezing Climate: ○ Yes ○ No			
32				
33	**UTILITIES**			
34	○ Steam for Auxiliaries:			
35	Fan Turbine Throttle (psig):	Maximum Pressure (psig):	Minimum Temperature (ºF):	
36	Exhaust Pressure (psig):	Exhaust Temperature (ºF):		
37	Sootblowers (from Plant Mains) (psig):			
38	Atomizing Steam (psig): (ºF):			
39	○ Electrical Power Supply:	Area Classification:		
40	Frequency [(Hz) 3-Phase]:			
41	Motors:	Through (hp):	Volts:	
42		Over (hp):	Volts:	
43	Instruments (volts):			
44	○ Cooling Water: Inlet: psig @ ºF	Outlet: psig @ ºF		
45	○ Condensate:	psig @ ºF for Desuperheater		
46	○ Plant Air (psig)	Oil Free ○ Yes ○ No		
47	○ Instrument Air (psig):	Dry and Oil Free ○ Yes ○ No	○ Dewpoint: ºF @ psig	
48				
49	**Remarks:**			
50				
51				
52				
53				
54				
55				

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1	DESIGN, MANUFACTURE & TESTING SHALL CONFORM TO SPECIFICATION: ○ API RP-538 ○ Other							
2	INFORMATION TO BE COMPLETED: ○ BY PURCHASER ☐ BY MANUFACTURER ⊡ BY PURCHASER OR MANUFACTURER							
3	Manufacturer		Model			Quantity		
4	**PERFORMANCE DATA**							
5	Operation		**Design**	Normal	Minimum	75% MCR	50% MCR	25% MCR
6	○ Steam Flow	lb/h						
7	○ Name of fuel							
8	○ Blowdown	%						
9	☐ Excess Air	%						
10	☐ Maximum Heat Absorption Rate	Btu/ft²-h						
11	☐ Maximum Heat Liberation Rate	Btu/ft³-h						
12								
13	☐ **Quantity**	kpph						
14	Fuel Flow							
15	Flue Gas Leaving Boiler							
16	Air Flow Leaving FD Fan							
17	Flue Gas Recirculation Flow							
18	Steam Flow @ Superheater Outlet							
19	Desuperheater Spray Flow							
20	☐ **Temperature**	°F						
21	Final Steam Temperature							
22	Steam Leaving Superheater							
23	Flue Gas Leaving Boiler							
24	Flue Gas Leaving Economizer							
25	Water Leaving Economizer							
26	Water Entering Economizer							
27	☐ **Pressure**	psig						
28	Battery Limit (Steam outlet)							
29	Superheater Outlet							
30	Drum							
31	Economizer Inlet (Feedwater)							
32	☐ **Air Resistance**	in. H_2O						
33	Burners							
34	Ducts / Windbox							
35	Net Resistance							
36	☐ **Draft Losses**	in. H_2O						
37	Firebox							
38	Boiler & Superheater							
39	Economizer							
40	Flues / Stack							
41	Other							
42	Net Draft Loss							
43	☐ **% Heat Loss** **(by HHV)**							
44	Dry Gas							
45	Moisture in Fuel							
46	Unburned Combustible							
47	Radiation							
48	Manufacturer's Margin							
49	Total							
50	☐ **Net Efficiency** (by Higher Heating Value)	%						
51	(by Lower Heating Value)	%						
52	**Remarks:**							
53								
54								
55								

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1	**GUARANTEED PERFORMANCE**		
2	○ Fuel		FOR ALL IDENTIFIED OPERATING CASES.
3	○ Rated Capacity	lb/h	○ NOx:
4	○ Steam Temperature @ Terminal Point	ºF	○ SOx:
5	○ Steam Pressure @ Terminal Point	psig	○ CO:
6	○ Thermal Efficiency	%	○ HC:
7	○ Boiler Control Range (Min steam flow @ design temp)	lb/h	○ Particulate:
8	○ Min Steam Flow @ Steam Temp. lb/h @	ºF	
9	○ FD Fan Static Pressure	in. of H_2O	○ Solids in Steam:
10	○ FD Fan Power (max.)	kW	○ % Dryness of Steam @ Drum Exit
11			
12			
13	**GUARANTEE BASIS**		
14	○ Feedwater Temperature	ºF	○ Fuels
15	○ Ambient Temperature - Max Min	ºF	○ Higher Heating Value ○ Lower Heating Value
16	○ Altitude (above Sea Level)	ft	○ Humidity (lb moisture / lb dry air)
17	○ Blowdown (% Rated Capacity)		
18			
19			
20			
21	**BOILER FEEDWATER ANALYSIS**		
22	○ pH @ 25 ºC		Total (mg/l) Dissolved (mg/l)
23	○ P Alkalinity	mg/l $CaCO_3$	○ Calcium (Ca)
24	○ M Alkalinity	mg/l $CaCO_3$	○ Magnesium (Mg)
25	○ Conductivity	micromhos/cm (un-neutralized)	○ Sodium (Na)
26	○ Total Dissolved Solids (TDS)	mg/l	○ Potassium (K)
27	○ Total Suspended Solids (TSS)	mg/l	○ Iron (Fe)
28			○ Copper (Cu)
29	○ Hydroxide (OH)	mg/l	○ Manganese (Mn)
30	○ Carbonate (CO_3)	mg/l	○ Aluminum (Al)
31	○ Bicarbonate (HCO_3)	mg/l	○ Zinc (Zn)
32	○ Total Silica (SiO_2)	mg/l	○ Nickel (Ni)
33	○ Chloride (Cl)	mg/l	○ Chromium (CrO_4)
34	○ Sulfate (SO_4)	mg/l	○ Carbon Dioxide (CO_2)
35	○ Ortho Phosphate (PO_4)	mg/l	○ Organics
36			
37			
38			

39	**Weights**				**Dimensions** (preliminary)		
40	lbs	Boiler	Economizer	Stack		**Overall Boiler**	**Overall Plot Space**
41	☐ Shipping				Length (ft-in.):		
42	☐ Operating				Width (ft-in.):		
43	☐ Full of Water				Height (ft-in.):		
44							
45	☐ Steam Drum shipping weight: lbs						
46	(when supplied as a separate item)						
47							
48							
49	**Remarks:**						
50							
51							
52							
53							
54							
55							

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1	**BOILER**					
2	Manufacturer:			Type:		
3	Design Code:			No. of Boilers:		
4	Maximum Continuous Rating:		lb/h	Peak Rating: (special)		lb/h
5	Superheater Outlet Pressure:		psig	Temperature:	ºF	(Downstream of NRV)
6	Feedwater Pressure required at:	Economizer (psig):		Control Station (psig):		
7	**Construction Details**					
8	**Firebox**	Tube OD (in.)	Tube Thickness (in.)	Tube Pitch (in.)	Corr Allow (in.)	Tube Material
9	Side Walls					
10	Division Walls					
11	Roof					
12	Floor					
13	Rear Wall					
14	Front Wall					
15	Firebox Volume (ft³):			Projected Heating Surface Based on EPRS (ft²):		
16	Furnace Length (ft-in.):	Width (ft-in.):		Height (ft-in.):		
17	**Superheater Screen**					
18	Arrangement:	☐ Staggered	☐ In-Line	☐ Single Row	☐ None	
19	Tube:	OD (in.):	Thickness (in.):	Corr Allow (in.)	Material:	
20	No. of Tubes Wide:	Pitch (in.):		Gas Space: Width (ft-in.):	Height (ft-in.):	
21	No. of Rows Deep:	Pitch (in.):		Gas Velocity (ft/s):	Mass Flow (lb/h):	
22	Effective Heating Surface (ft^2):			Effective Tube Length (ft-in.):		
23	**Superheater**					
24	Type:	☐ Drainable	☐ Non-drainable	☐ Radiant Convection	☐ Convection	
25	Arrangement:	☐ Staggered	☐ In-Line	☐ U-Tube	☐ Pendant	☐ Horizontal ☐ Vertical
26	**Primary Superheater**					
27	No. of Tubes Wide:	Pitch (in.):	No. of Steam Passes:	Gas Space: Width (ft-in.):	Height (ft-in.):	
28	No. of Rows Deep:	Pitch (in.):	No. of Gas Passes:	Gas Velocity (ft/s):	Mass Flow (lb/h):	
29	Tubes:	OD (in.):	Thickness (in.):	Material:	No. of Rows:	
30		OD (in.):	Thickness (in.):	Material:	No. of Rows:	
31		OD (in.):	Thickness (in.):	Material:	No. of Rows:	
32		Corrosion Allowance (in.):				
33	Effective Heating Surface (ft^2):			Effective Tube Length (ft-in.):		
34	Metal Temperature (ºF):	Design (ºF):	Max. (ºF) (First Row):	Max. (ºF) (Last Row):		
35						
36	**Secondary Superheater**					
37	No. of Tubes Wide:	Pitch (in.):	No. of Steam Passes:	Gas Space: Width (ft-in.):	Height (ft-in.):	
38	No. of Rows Deep:	Pitch (in.):	No. of Gas Passes:	Gas Velocity (ft/s):	Mass Flow (lb/h):	
39	Tubes:	OD (in.):	Thickness (in.):	Material:	No. of Rows:	
40		OD (in.):	Thickness (in.):	Material:	No. of Rows:	
41		OD (in.):	Thickness (in.):	Material:	No. of Rows:	
42		Corrosion Allowance (in.):				
43	Effective Heating Surface (ft^2):			Effective Tube Length (ft-in.):		
44	Metal Temperature (ºF):	Design (ºF):	Max. (ºF) (First Row):	Max. (ºF) (Last Row):		
45						
46	**Intermediate Screen**					
47	Arrangement:	☐ Staggered	☐ In-Line	☐ Single Row	☐ None	
48	Tube:	OD (in.):	Thickness (in.):	Corr Allow (in.)	Material:	
49	No. of Tubes Wide:	Pitch (in.):		Gas Space: Width (ft-in.):	Height (ft-in.):	
50	No. of Rows Deep:	Pitch (in.):		Gas Velocity (ft/s):	Mass Flow (lb/h):	
51	Effective Heating Surface (ft^2):			Effective Tube Length (ft-in.):		
52	**Remarks:**					
53						
54						
55						

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☐ **Boiler Bank (Evaporator Section)**				
Arrangement:	☐ Staggered	☐ In-Line		
Tube:	OD (in.):	Thickness (in.):	Corr Allow (in.)	Material:
No. of Tubes Wide:	Pitch (in.):	Gas Space: Width (ft-in.):	Height (ft-in.):	
No. of Rows Deep:	Pitch (in.):	Gas Velocity (ft/s):	Mass Flow (lb/h):	
Effective Heating Surface (ft^2):		Effective Tube Length (ft-in.):		
☐ **Economizer**				
Manufacturer:	Type:	☐ Bare Tube ☐ Finned	Fin Type: ☐ Solid ☐ Segmented	
Arrangement:	☐ Staggered	☐ In-Line	Mounting (tube orientation)	☐ Horizontal ☐ Vertical
Tube:	OD (in.):	Thickness (in.):	Corr Allow (in.)	Material:
Fins:	Height (in.):	Thickness (in.):	Spacing (# fins/in.):	Material:
No. of Tubes Wide:	Pitch (in.):	Gas Space: Width (ft-in.):	Height (ft-in.):	
No. of Rows Deep:	Pitch (in.):	Gas Velocity (ft/s):	Mass Flow (lb/h):	
Effective Heating Surface (ft^2):	Total: (ft^2) bare	Effective Tube Length (ft-in.):		
No. of Water Passes:	No. of Gas Passes:	Min. Tube Metal Temp (ºF):		
☐ **Air Heater**				
Manufacturer:		Type (Recuperative):		
Arrangement:	☐ Staggered	☐ In-Line	☐ Horizontal	☐ Vertical
Air:	☐ Inside Tubes	☐ Outside Tubes		
Tube:	OD (in.):	Thickness (in.):	Corr Allow (in.)	Material:
No. of Tubes Wide:	Pitch (in.):	No. of Air Passes:		
No. of Rows Deep:	Pitch (in.):	No. of Gas Passes:		
Effective Heating Surface (ft^2):		Effective Tube Length (ft-in.):		
Minimum Calculated Tube Material Temperature (ºF):		Corrosion Prevention Feature:		
☐ **Steam Drum**				
Design Pressure (psig):	Design Temperature (ºF):	ID (in.):	Straight Length (ft-in.):	
Tube Plate Thickness (in.):	Wrapper Plate Thickness (in.):	Material:		
Type of Heads:	ID (in.):	Thickness (in.):	Material:	
Manholes:	No.	Size:	Lengths Between Welds (ft-in.):	
Tube Connection:	☐ Welded	☐ Expanded	☐ Both	Ligament Efficiency:
Normal Water Level (NWL):	Below Drum Centerline (in.):	Above Drum Centerline (in.):		
High Water Level:	(in.) Above NWL:	Low Water Level:	(in.) Below NWL:	
Water Level Cutoff:	(in.) Below NWL (Low):	(in.) Above NWL (High):		
Drum Volume:	ft³ (Below NWL):	ft³ (Between LLA and LLCO):		
Steam Drum Retention Time (minutes):		(between Normal Water Level (NWL) and Low Low Trip (LLT))		
Steam Drum Internals				
Brief Description:				
Separators:	Qty:	Type:	Manufacturer:	Model No.
Dryers	Qty:	Type:	Manufacturer:	Model No.
Water (lower) Drum				
Design Pressure (psig):	Design Temperature (ºF):	ID (in.):	Straight Length (ft-in.):	
Tube Plate Thickness (in.):	Material:			
Type of Heads:	ID (in.):	Thickness (in.):	Material:	
Manholes:	No.	Size:	Lengths Between Welds (ft-in.):	
Tube Connection:	☐ Welded	☐ Expanded	☐ Both	Ligament Efficiency:
Volume of Water Drum (ft³)		Total Internal Volume of Tubes (ft³):		
Vertical Distance Between Steam and Water Drums (ft):				

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Wall Headers					
Location:			Design Pressure (psig):		Corr Allow (in.)
OD (in.):	Thickness (in.):	Material:	Tube Connection:	☐ Welded ☐ Expanded	☐ Both
Supplies No.:	OD (in.):	Thickness (in.):	Material:		
Risers No.:	OD (in.):	Thickness (in.):	Material:		
Location:			Design Pressure (psig):		Corr Allow (in.)
OD (in.):	Thickness (in.):	Material:	Tube Connection:	☐ Welded ☐ Expanded	☐ Both
Supplies No.:	OD (in.):	Thickness (in.):	Material:		
Risers No.:	OD (in.):	Thickness (in.):	Material:		
Location:			Design Pressure (psig):		Corr Allow (in.)
OD (in.):	Thickness (in.):	Material:	Tube Connection:	☐ Welded ☐ Expanded	☐ Both
Supplies No.:	OD (in.):	Thickness (in.):	Material:		
Risers No.:	OD (in.):	Thickness (in.):	Material:		
Location:			Design Pressure (psig):		Corr Allow (in.)
OD (in.):	Thickness (in.):	Material:	Tube Connection:	☐ Welded ☐ Expanded	☐ Both
Supplies No.:	OD (in.):	Thickness (in.):	Material:		
Risers No.:	OD (in.):	Thickness (in.):	Material:		

Primary Superheater Headers				
Inlet	OD (in.):	Thickness (in.):	Material:	
Outlet	OD (in.):	Thickness (in.):	Material:	
Tube Connection:	☐ Welded	☐ Expanded	☐ Both	Corr Allow (in.)
Saturated Connections No.:	OD (in.):	Thickness (in.):	Material:	
Secondary Superheater Headers				
Inlet	OD (in.):	Thickness (in.):	Material:	
Outlet	OD (in.):	Thickness (in.):	Material:	
Tube Connection:	☐ Welded	☐ Expanded	☐ Both	Corr Allow (in.)
Economizer Headers				
Inlet	OD (in.):	Thickness (in.):	Material:	
Outlet	OD (in.):	Thickness (in.):	Material:	
Tube Connection:	☐ Welded	☐ Expanded	☐ Both	Corr Allow (in.)
Connection to Drum No.:	OD (in.):	Thickness (in.):	Material:	

☐Attemperator / Desuperheater			
No. Required:	Manufacturer:	Type: ☐ Non-contact	☐ Spray
☐ Design Flow (steam)	lb/h	Location ☐ Interstage	☐ Superheater outlet
☐ Design Flow (water)	lb/h	○ Spray Water Temperature	ºF
○ Spray Water Source		○ Spray Water Pressure	psig

Access Requirements (Platforms / Ladders / Stairs)

Furnished by ○ Purchaser ○ Supplier ○ Material ○ Loading lb/ft²

Typical Locations:	Platform	Ladder	Stairs		Platform	Ladder	Stairs
Boiler Front (Burner decks)	x		x	Economizer	x	caged	
FD Fan and driver	x	x		Stack	x	caged	
Steam Drum (Heads & PRV's)	x	x	x	Inspection ports	x	x	
Lower Drum (Manways)	x	x		Access Hatches	x	x	

Remarks:

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1	**Refractory and Insulation**			
2	○ Design Basis: Ambient Temperature ºF	Wind Velocity (mph)		Casing Temperature ºF
3				
4	☐ **Exposed Vertical Walls**			
5	Lining Thickness (in.):	Hot-face Temperature (ºF):	Design:	Calculated:
6	Wall Construction:			
7				
8	Anchor (material and type)			
9	Casing material	Thickness (in.):		Temperature (ºF):
10	☐ **Shielded Vertical Walls**			
11	Lining Thickness (in.):	Hot-face Temperature (ºF):	Design:	Calculated:
12	Wall Construction:			
13				
14	Anchor (material and type)			
15	Casing material	Thickness (in.):		Temperature (ºF):
16	☐ **Burner Throat**			
17	Lining Thickness (in.):	Hot-face Temperature (ºF):	Design:	Calculated:
18	Wall Construction:			
19				
20	Anchor (material and type)			
21	Casing material	Thickness (in.):		Temperature (ºF):
22				
23	☐ **Floor**			
24	Lining Thickness (in.):	Hot-face Temperature (ºF):	Design:	Calculated:
25	Floor Construction:			
26				
27	Anchor (material and type)			
28	Casing material	Thickness (in.):		Temperature (ºF):
29	Minimum Floor Elevation (in.):	Free Space below Tubes (in.):		
30				
31	☐ **Convection Section**			
32	Lining Thickness (in.):	Hot-face Temperature (ºF):	Design:	Calculated:
33	Wall Construction:			
34				
35	Anchor (material and type)			
36	Casing material	Thickness (in.):		Temperature (ºF):
37				

38	☐ **Ducts:**	**Combustion Air**		**Flue Gas**		
39	Location					
40	Size or net free area (ft²)					
41	Casing material					
42	Casing Thickness (in.):					
43	Lining: Internal / external					
44	Thickness (in.):					
45	Material					
46	Anchor (material and type)					
47	Casing temperature (ºF):					
48						

49	☐**Windbox**			
50	Casing material	Thickness (in.):		Size (in.):
51	Lining material	Thickness (in.):	Design:	Calculated:
52	Anchor (material and type)			
53	**Remarks:**			
54				
55				

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1	**FORCED DRAFT FAN**					**INDUCED DRAFT FAN**				
2	No. Required:	Manufacturer:				No. Required:	Manufacturer:			
3	Type:					Type:				
4	Speed (rpm):	Impeller Diameter (in.):				Speed (rpm):	Impeller Diameter (in.):			
5	Flow Control Device:					Flow Control Device:				
6	Air Flow	Oil: cfm	ºF	in of H_2O	hp	Gas Flow	Oil: cfm	ºF	in of H_2O	hp
7	at MCR:	Gas: cfm	ºF	in of H_2O	hp	at MCR:	Gas: cfm	ºF	in of H_2O	hp
8	Test Block:	cfm	ºF	in of H_2O	hp	Test Block:	cfm	ºF	in of H_2O	hp
9	Fan Sound Level:	(dBA) at	ft from Fan			Fan Sound Level:	(dBA) at	ft from Fan		
10	Detailed information shown on separate Fan data sheet.					Detailed information shown on separate Fan data sheet.				
11	Motor Driver:	Manufacturer:				Type	hp:			
12		Motor Sound Level:	(dBA) at	ft from Motor						
13										
14	Steam Turbine Driver:	Manufacturer:				Type				
15		Water Rate:	lb/hp/h			Horsepower:				
16		Exhaust Steam Temperature (ºF):				Governor:	☐ Mechanical	☐ Hydraulic		
17		Turbine Sound Level:	(dBA) at	ft from Turbine						
18										
19	**Air Ducts**									
20	FD Fan Suction:	Size (ft-in.):	Thickness (in.):	Corr Allow (in.)	Material:					
21	FD Fan to Windbox:	Size (ft-in.):	Thickness (in.):	Corr Allow (in.)	Material:					
22	(Air Heater)	Venturi Included:	◯ Yes	◯ No						
23		Damper Included:	◯ Yes	◯ No	Damper:	◯ Single vane	◯ Multivane			
24		Expansion Joints:	No.:	Location:	Type:					
25		Maximum Design Temperature (ºF):			Manufacturer:					
26		Supports Included:	◯ Yes	◯ No	Max. Air Velocity (ft/s):					
27	Air Htr to Windbox	Size (ft-in.):	Thickness (in.):	Corr Allow (in.)	Material:					
28		Expansion Joints:	No.:	Location:	Type:					
29		Maximum Design Temperature (ºF):			Manufacturer:					
30		Supports Included:	◯ Yes	◯ No	Max. Air Velocity (ft/s):					
31	**Flue Gas Ducting**									
32	Boiler to:	Size (ft-in.):	Thickness (in.):	Corr Allow (in.)	Material:					
33	◯ Economizer	Expansion Joints:	No.:	Location:	Type:					
34	◯ Air Heater	Maximum Design Temperature (ºF):			Manufacturer:					
35		Supports Included:	◯ Yes	◯ No	Max. Gas Velocity (ft/s):					
36	◯ Boiler	Size (ft-in.):	Thickness (in.):	Corr Allow (in.)	Material:					
37	◯ Economizer	Damper Included:	◯ Yes	◯ No	Damper:	◯ Single vane	◯ Multivane			
38	◯ Air Heater	Expansion Joints:	No.:	Location:	Type:					
39	TO:	Maximum Design Temperature (ºF):			Manufacturer:					
40	◯ Main Flue	Supports Included:	◯ Yes	◯ No	Max. Gas Velocity (ft/s):					
41	◯ Stack									
42	Main Duct	Size (ft-in.):	Thickness (in.):	Corr Allow (in.)	Material:					
43		Terminal Point:								
44		Damper Included:	◯ Yes	◯ No	Damper:	◯ Single vane	◯ Multivane			
45		Expansion Joints:	No.:	Location:	Type:					
46		Maximum Design Temperature (ºF):			Manufacturer:					
47		Isolating Blind included:	◯ Yes	◯ No	Max. Gas Velocity (ft/s):					
48	**Stack**									
49	Furnished by	◯ Supplier	◯ Purchaser	Height (ft-in.):	Type	◯ Self-Supporting	◯ Supported			
50	Inside diameter (ft-in.):	Base:	Top:	Thickness (in.):	Corr Allow (in.)	Material:				
51	Max. Gas Velocity (ft/s):	Lining:	Thickness (in.):	Material:						
52	◯ FAA Lighting Required	◯ Caged Ladder to Test Platform	◯ Personnel Protection Screen							
53	◯ CEMS Ports	◯ Access Door	◯ Vibration Isolation							
54										
55										

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BURNERS

	Number	Type	Manufacturer	Model	Turndown	Heat Input / Burner	Atom. Steam or Air
○ Gas							
○ Oil							
○ Igniter							

☐ Flame Scanner: Number: Manufacturer / Model: Type:

IGNITER / IGNITER SUPPLY SYSTEM

Furnished by: ○ Supplier ○ Purchaser			☐ Rated Capacity		Btu/h
○ Class I ○ Class II ○ Class III					
Auto Retraction of Spark Device: ○ Yes ○ No				Manufacturer	Model
	Manufacturer	Size	Press. Ind. (w / S.O. Valves)		
Auto Vent Valve			Hi/Lo Pressure Switch		
Auto Shutoff Valve			Pressure Regulator		
Manual Shutoff Valve			Drip Leg		

MAIN BURNER SUPPLY SYSTEM (GAS FIRING)

Furnished by ○ Supplier ○ Purchaser			☐ Rated Capacity		Btu/h
○ Burner Type					
				Manufacturer	Model
	Manufacturer	Size	Pressure Regulator		
Auto Vent Valve			Gas Strainer		
Auto Shutoff Valve			Hi/Lo Pressure Switch		
Manual Shutoff Valve			Press. Ind. (w / S.O. Valves)		
Vent Leak Valve			Drain Valve		
Gas Flow Control Valve					

MAIN BURNER SUPPLY SYSTEM (OIL FIRING)

Furnished by ○ Supplier ○ Purchaser			☐ Rated Capacity		Btu/h
○ Burner Type					
				Manufacturer	Model
	Manufacturer	Size	Low Pressure Switch		
Recirculation Valve			Oil Strainer		
Auto Shutoff Valve			Check Valve		
Manual Shutoff Valve			Press. Ind. (w / S.O. Valves)		
Vent Leak Valve			Drain Valve		
Oil Flow Control Valve					

ATOMIZING AIR / STEAM (OIL FIRING ONLY)

Furnished by ○ Supplier ○ Purchaser			☐ Rated Capacity		lb/h
	Manufacturer	Size		Manufacturer	Model
Auto Shutoff Valve			Low Pressure Switch		
Manual Shutoff Valve			Press. Ind. (w / S.O. Valves)		
Control Valve			Drain w/ Trap		
Check Valve					
Strainer					

COMBUSTION CONTROLS AND BURNER MANAGEMENT

○ Burner Management System	○ Panel Enclosure:			
○ Combustion Controls	Power Supplies	Voltage	Phase	Hertz
○ Control Type	○ Instrument / Control Power			
	○ Control Panel Power			

Remarks:

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1	**FUEL ANALYSIS**								
2	FUEL GAS			IGNITER GAS			LIQUID		
3	Composition by:			Composition by:					
4	○ Mole % ○ Volume % ○ Weight %			○ Mole % ○ Volume % ○ Weight %					
5		**Design**	**Range**		**Design**	**Range**		**Design**	**Range**
6	Fuel			Fuel			Ultimate Analysis	(Weight Percent)	
7	Hydrogen Sulfide (H_2S)			Hydrogen Sulfide (H_2S)			Carbon		
8	Hydrogen (H_2)			Hydrogen (H_2)			Hydrogen		
9	Nitrogen (N_2)			Nitrogen (N_2)			Oxygen		
10	Carbon dioxide (CO_2)			Carbon dioxide (CO_2)			Nitrogen		
11	Methane (CH_4)			Methane (CH_4)			Sulfur		
12	Ethane (C_2H_6)			Ethane (C_2H_6)			Ash		
13	Ethylene (C_2H_4)			Ethylene (C_2H_4)			Moisture		
14	Propane (C_3H_8)			Propane (C_3H_8)			**Total**	100	
15	Propylene (C_3H_6)			Propylene (C_3H_6)					
16	Isobutane (C_4H_{10})			Isobutane (C_4H_{10})			Flash Point (ºF):		
17	Butylene (C_4H_8)			Butylene (C_4H_8)			Specific Gravity (ºAPI):		
18	N-Butane (C_4H_{10})			N-Butane (C_4H_{10})			Viscosity (dyna) (cP):		
19	Isopentane (C_5H_{12})			Isopentane (C_5H_{12})			Viscosity (kine) (cSt):		
20	Pentane (C_5H_{12})			Pentane (C_5H_{12})			Total H_2: (wt%)		
21	Hexane (C_6+)			Hexane (C_6+)			Ash Fusion Temp (ºF):		
22	Oxygen (O_2)			Oxygen (O_2)			Sodium (ppm):		
23	Carbon Monoxide (CO)			Carbon Monoxide (CO)			Vanadium (ppm):		
24	**Total**			**Total**			Nickel (ppm):		
25									
26	Heating Values			Heating Values			Heating Values		
27	Higher (Btu/lb)			Higher (Btu/lb)			Higher (Btu/lb)		
28	Lower (Btu/lb)			Lower (Btu/lb)			Lower (Btu/lb)		
29	Higher (Btu/scft)			Higher (Btu/scft)					
30	Lower (Btu/scft)			Lower (Btu/scft)					
31	Mole Weight			Mole Weight					
32	Design Temp. ºF			Design Temp. ºF			Design Temp. ºF		
33	Header Pressure: (max) psig			Header Pressure: (max) psig			Header Pressure: (max) psig		
34	Header Pressure: (min) psig			Header Pressure: (min) psig			Header Pressure: (min) psig		
35									

36	**FUEL RATES**						
37	Case Number	Design	Normal	Minimum	75%	50%	25%
38		Case					
39	Primary Gas lb/h						
40							
41							
42							
43							
44							
45							
46							
47							
48							
49	**Remarks:**						
50							
51							
52							
53							
54							
55							

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BURNERS / PILOTS

FUEL ○ Liquid	○ Gas	○ Dual	NFPA fuel train by	○ Supplier	○ Purchaser
○ Liquid Pressure at Inlet		psig	Firing	☐ Single Wall	☐ Opposed Wall
○ Gas Pressure at Inlet		psig		☐ Tangential	☐ Other

FLAME SCANNERS

○ Single ○ Dual ○ Number per Burner

Sensor Type ○ Infrared ○ Ultraviolet

BURNERS / PILOTS	Fuel Gas	Waste Gas	Fuel Oil	Waste Oil	Other
☐ Type					
☐ Manufacturer					
☐ Model					
☐ Number Required					
☐ Number Burners / Level					
☐ Number of Levels					
☐ Turndown					
☐ Heat Input / Burner					
☐ Fuel Consumption / Burner					
☐ Qty. Atomizing Steam / Air					
☐ Excess Air %					
☐ Pilot Fuel					
BURNER DETAILS					
☐ Dimensions					
☐ Pull Out Length					
☐					

SOOTBLOWERS

	Manufacturer	Model	Type	Quant	Consumption	Oper Press	Oper Temp
					lb/h	psig	ºF
☐ Firebox							
☐ Convection Pass							
☐ Secondary S.H.							
☐ Primary S.H.							
☐ Economizer							
☐ Air Preheater							
☐							

○ Automatic Sequencing Required Piping by ○ Supplier ○ Purchaser ○ includes Steam Admission Valve

Media ○ High Pressure Steam ○ Medium Pressure Steam ○ Compressed Air ○ Plant Air

Additional Equipment by Supplier ○ PLC Control Panel, Local PB Stations (each unit)

○ Relief Valve ○ Pressure Transmitter ○ Thermal Drain Valves

Remarks:

API 538 WATER TUBE BOILER DATA SHEET

(USC Units)

REVISIONS	0	1	2	3	4
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APPROVED					

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BOILER VALVE SUMMARY

DESCRIPTION **D = Double Valves**		Number Required	Size Inch	End Type	Rating	Operator Type	Remarks
Boiler safety valve							
Boiler safety valve							
Superheater safety valve							
Main steam non-return valve							
Main steam stop valve							
Main steam stop bypass valve							
Main steam drain valve							
Main steam stop bypass drain valve							
Feedwater control valve							
Feedwater control valve isolation valve (inlet)							
Feedwater control valve isolation valve (outlet)							
Feedwater control valve bypass valve							
Feedwater control valve drain valves							
Boiler feed stop valve							
Boiler feed check valve							
Boiler vent valve							
Feedwater sample valves	**D**						
Steam gauge shut-off valve							
Steam gauge drain valve	**D**						
Water column & tie bar isolation valves							
Water column & tie bar drain valves	**D**						
Water column vent valves							
Gauge glass drain valves	**D**						
Desuperheater control valve							
Intermittent blowdown valves	**D**						
Waterwall lower header blow off valves	**D**						
Boiler drain valves							
Chemical feed shut-off valve							
Chemical feed check valve							
Continuous blowdown shut-off valve							
Continuous blowdown needle valve							
Saturated steam sampling shut-off valves							
Superheater vent valves	**D**						
Superheater start-up vent valves	**D**						
Superheater drain valves	**D**						
Spray water control valve isolation valves							
Spray water control valve bypass valve							
Spray water control valve drain valves							
Desuperheater spray water shut-off valve							
Desuperheater spray water check valve							
Spray water header drain valve							
Sample cooler water inlet valve							
Economizer vent valve							
Economizer drain valves	**D**						
Economizer bypass valve							(not normally required)
Economizer safety valve							(not normally required)
Level transmitter shut-off valves							

Remarks:

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API 538 WATER TUBE BOILER DATA SHEET

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TRANSMITTERS

○ Electronic ○ "Smart" Type

Service	Supplied by: Supplier	Supplied by: Purchaser	Shop Installed	Redundancy Required
Feedwater Pressure	○	○	☐	○
Drum Pressure	○	○	☐	○
Fuel Pressure	○	○	☐	○
Steam Pressure	○	○	☐	○
Furnace Pressure	○	○	☐	○
Windbox Pressure	○	○	☐	○
Boiler Outlet Pressure	○	○	☐	○
Economizer Outlet Pressure	○	○	☐	○
Feedwater Flow	○	○	☐	○
Fuel Flow	○	○	☐	○
Steam Flow	○	○	☐	○
Air Flow	○	○	☐	○
Drum Level	○	○	☐	○
Aux Low Water Cutout	○	○	☐	○
Steam Temperature	○	○	☐	○
Furnace Temperature	○	○	☐	○
Econ Inlet Gas Temp	○	○	☐	○
Econ Outlet Gas Temp	○	○	☐	○

Drum level instruments to be mounted on bridles: ○ Yes ○ No

CONTROL PANEL

Enclosure ○ NEMA 4X ○ Other

Area Classification ○ Unclassified

○ Class ○ Group ○ Div

PLC by ○ Supplier ○ Purchaser

PLC Manufacturer:

PLC includes:

- ○ Processor
- ○ Register Pack
- ○ Data Highway Module
- ○ Memory: Capacity =
- ○ I/O: Minimum pairs each

FLOW METERS

Air Flow	Fuel Flow
☐ Manufacturer	☐ Manufacturer
☐ Model	☐ Model
☐ Type	☐ Type
☐ Range	☐ Range
Steam Flow	**Feedwater Flow**
☐ Manufacturer	☐ Manufacturer
☐ Model	☐ Model
☐ Type	☐ Type
☐ Range	☐ Range

DCS SIGNALS (required for Purchaser)

Input Signals to DCS

- ○ Boiler Trip
- ○ Common Trouble Alarm
- Steam: ○ Pressure ○ Temperature ○ Flow
- Steam Drum: ○ Pressure ○ Level
- ○ Fuel Pressure
- ○ Economizer Outlet Flue Gas Temperature

Output Signals from DCS

- ○ Steam Pressure
- ○ Fuel Flow
- ○ Feedwater Flow
- ○ Fuel / Air Ratio Control

ANALYZERS

Analyzers by ○ Supplier ○ Purchaser

Oxygen Analyzer	NOx Analyzer
☐ Manufacturer	☐ Manufacturer
☐ Model	☐ Model
☐ Range	☐ Range

DRUM INSTRUMENTATION

	Type	Manufacturer	Range
☐ Water Column			
☐ Level Gauges			
☐ Press. Gauges			
☐ Temp. Gauges			

RELIEF VALVES AND SILENCERS

Drum Relief Valve #1	Superheater Relief Valve
☐ Manufacturer	☐ Manufacturer
☐ Model	☐ Model
☐ Set Point psig	☐ Set Point psig
Drum Relief Valve #2	**Silencer - Superheater Vent (start-up)**
☐ Manufacturer	☐ Manufacturer
☐ Model	☐ Model
☐ Set Point psig	☐ Noise Level dBA

Remarks:

API 538 WATER TUBE BOILER DATA SHEET

(USC Units)

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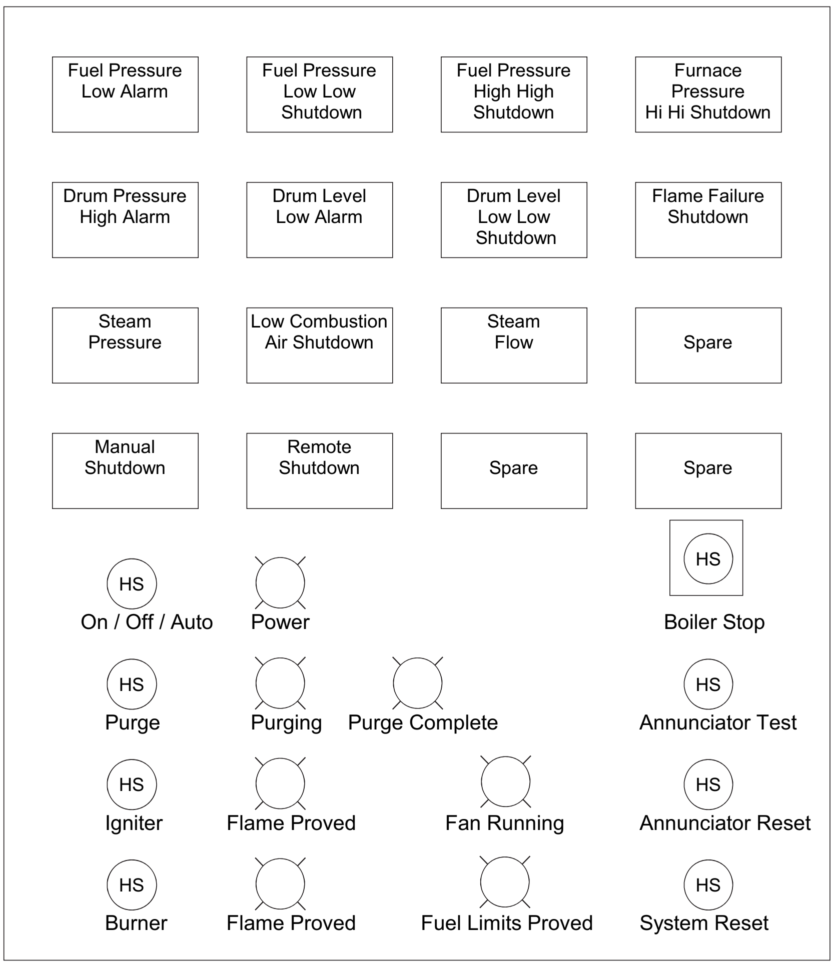
LOCAL CONTROL PANEL



☐ Panel Dimensions: ______ W x ______ L x ______ H   Access Door: ○ Front ○ Rear

Remarks: Annunciator windows to be a minimum of:

API 538 WATER TUBE BOILER DATA SHEET

(USC Units)

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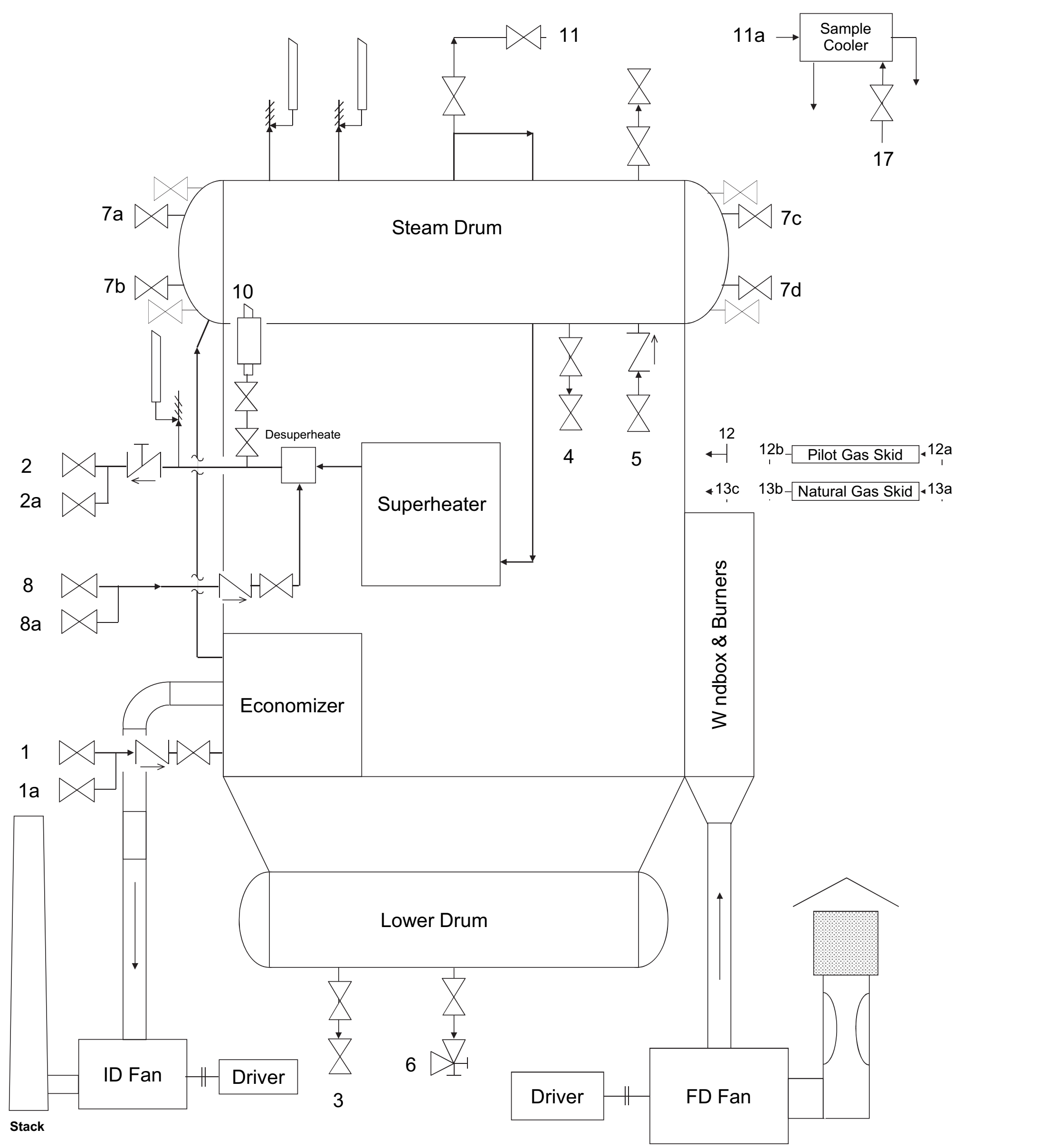
TYPICAL CUSTOMER CONNECTION



NOTE This sketch does not show all the various connections required for vents, drains, and instrument air.

API 538 WATER TUBE BOILER DATA SHEET

(USC Units)

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TYPICAL CUSTOMER CONNECTION SUMMARY

#	DESCRIPTION	Size (inch)	End Type	Rating Schedule	Flange Face	Weld Prep	Remarks
1	Feedwater Inlet						
2	Steam Outlet						
3	Intermittent Blowdown						
4	Continuous Blowdown						
5	Chemical Injection						
6	Economizer Drain						
7(a-d)	Level Transmitters						
8	Desuperheater Water Inlet						
9	Drum Vent						
10	Start-up Vent Outlet						
11	Saturated Steam Sample						
12a	Pilot Gas Inlet (Fuel Skid)						
12b	Pilot Gas Outlet (Fuel Skid)						
12c	Pilot Gas Inlet (to Burner)						
13a	Natural Gas Inlet (Fuel Skid)						
13b	Natural Gas Outlet (Fuel Skid)						
13c	Natural Gas Inlet (to Burner)						

REMARKS:

AMERICAN PETROLEUM INSTITUTE

API 538 WATER TUBE BOILER DATA SHEET

(USC Units)

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INSTRUMENT SCOPE OF SUPPLY

DESCRIPTION	Element														Indication								Control by		
	Provided by				Type			Location			Installed by				Provided by				Location						
Instrument connection requirements to be established later.	Number of Units	Supplier	Purchaser		Direct Readout	Transmitter		Supplier Package	Purchaser Piping		Supplier		Purchaser		Supplier		Purchaser		@ Element	Local Panel	DCS	Local Panel + DCS	Local Panel	DCS	
Pressure Instruments																									
Drum Pressure																									
Superheater Outlet Pressure																									
Fuel Pressure																									
Furnace Pressure																									
Windbox Pressure																									
Temperature Instruments																									
TW / TE (Economizer IN/OUT)																									
TW / TE (Desuperheater IN/OUT)																									
TE (Superheater Surface)																									
Level Instruments																									
Water Columns (steam drum)																									
Bi-color ported gauge glass																									
with shut-off valves, illuminator, and viewing hood																									
Electrode type level monitor																									
with low level trip contact, relay with enclosure,																									
and blowdown holding switch																									
Fiber Optic Column																									
with fiber optic hardware, local detection unit in																									
a NEMA 4X cabinet with window for bicolor 12 point																									
display panel																									
Flow Instruments																									
Feedwater																									
Main Steam																									
Natural Gas																									
Air Flow																									
Miscellaneous Instruments																									
Pressure Relief Valve (steam drum)																									
Pressure Relief Valve (main steam)																									

Remarks:

Annex B
(informative)

Purchaser's Checklist (Part 1)

This checklist may be used to indicate the purchaser's specific requirements where the RP provides a choice or specifies that a decision shall be made.

These items are indicated by a bullet (●) in the RP.

Subsection	Item	Requirement
1.3	Define applicable codes such as ASME, ISO, etc.	__________ __________
	Data sheet information to be specified:	
4.1.3	— steam pressure (superheater non-return valve outlet),	
4.1.5	— capacity (steam flow at MCR),	
4.1.5	— lowest steam flow at rated temperature,	
4.1.6	— fuels (names and compositions).	
4.2.3.2	Define the applicable standards for the fans: — API 673, API 560, AMCA 801, etc.	
4.2.3.5	Insulate all ducts operating above 60 °C (140 °F).	Yes No
4.3.8	CO Boilers—Boiler can deliver the maximum steam production in fresh air operation to back up the steam system.	Yes No
4.10.1	The basis for the performance criteria has been established.	Yes No
4.10.2	Define the basis for the performance criteria: — steam outlet flow, — steam outlet temperature, — steam outlet pressure, — inlet streams: — water, — air, — fuel.	
4.10.6.2	Turndown conditions and requirements have been specified.	Yes No
5.2.3	Electric resistance welded (ERW) steel tubes are acceptable.	Yes No
5.2.3	Steam generating tube material has been specified, based on the highest anticipated metal temperatures and flue gas composition.	Yes No
5.2.3	The tube-to-drum connections shall be seal welded after rolling. (typically used for higher pressure boilers).	Yes No
5.3.3.1	For the economizer, should the inlet and outlet headers be inside or outside of the flue gas path?	__________ __________
5.4.3.2 d)	The steam drum water retention time between the normal water level (NWL) and the low level cutout (LLCO) has been specified.	Yes No
5.4.5	The boiler shall shut down at high water cutout (HWCO).	Yes No
5.5.3	Ribbed tubes are acceptable.	Yes No

Subsection	Item	Requirement
6.3.6	CFD or empirical correlations shall be used to determine the flame size (not normally required).	Yes No
6.4.3.2	The oxygen content in the flue gas has been specified.	Yes No
6.4.3.2	The allowable CO concentration in the flue gas has been specified.	Yes No
7.2.3.9 a) 4)	The automatic vent valve may be omitted only if a listed automatic valve-proving system is used.	Yes No
7.4.2.1	The upper and lower limit of the band of control for each controlled variable has been specified.	Yes No
7.4.2.2	The required firing rate at turndown operation is specified as: a) hot standby, b) 10 % of MCR firing rate, c) 25 % of MCR firing rate.	
7.4.2.3	The required rate of load change is specified as follows: a) 2 min from turndown to 100 % MCR, b) 5 min from turndown to 100 % MCR, c) 15 min from turndown to 100 % MCR, d) other rate load of change specified by owner/operator.	
7.4.6.2.4 and 7.4.6.3.4	The “load to combustion air flow” characterizer’s output values should be set at approximately 10 equally spaced operating points across the entire firing range of the boiler.	Yes No
7.9.1	The criteria for seat leakage rates have been established.	Yes No
7.10	Standard trips and alarms for the design of the burner management system will be used. Trips and alarms may be expanded during P&ID reviews of the various systems and HAZOPs reviews.	Yes No Yes No
8.1	API 560: — complete (required) operating data (such as flow rate, pressure, pressure rise, temperature, and inlet gas density) have been specified; — fan requirements are specified on the fan data sheets from API 560, Annex A.	Yes No Yes No
8.1	API 612: — the equipment’s normal operating point and any other required operating points, including the inlet and exhaust steam conditions and any extraction or induction steam quantities and pressures have been specified; — the maximum and minimum values of the inlet, exhaust, and extraction/induction steam conditions have been specified.	Yes No Yes No
8.1	API 614/ISO 10438: — general-purpose or special-purpose system specified.	Yes No
8.2	For forced-draft fans, provision of the inlet equipment and arrangements, including silencer(s) and transition piece(s), have been specified.	Yes No
8.2	The air intake height above grade has been specified.	Yes No
8.2	A preliminary arrangement of the equipment, including ducting and auxiliaries, has been provided.	Yes No
8.2	Foundation drawing review by the fan vendor is required.	Yes No

Subsection	Item	Requirement
8.2	The weather and environmental conditions in which the equipment (fan) shall operate have been specified, including: — maximum and minimum temperatures and — unusual humidity or dust problems.	 Yes No Yes No
8.3	Electrical-area classification for boiler equipment/system. Electrical-area classification for fuel train and burner front components (if different) (normally, non-classified).	__________ __________
8.3	The operating speed of the fan may exceed 1800 rpm.	Yes No
8.3	Fan arrangements 1, 8, and 9 (all with bearings mounted independent of the fan housing) may be used.	Yes No
8.3	Fan driver type. Site and utility conditions have been specified.	__________ __________ Yes No
8.3	Process variations for fan-driver sizing	Yes No
8.3	The starting conditions and method for the driven equipment have been specified.	Yes No
8.1 and 8.4	API 560: — complete (required) operating data (such as flow rate, pressure, pressure rise, temperature, and inlet gas density) have been specified.	Yes No
8.4	The fan static pressure rise and temperature required for the rated point have been specified.	Yes No
8.5	For fan control, the type and source of the control signal, its sensitivity and range, and the equipment scope to be furnished by the vendor has been specified.	Yes No
8.5	The fan vendor shall furnish and locate the operators, actuator linkages, and operating shafts for remote control of the dampers or variable-inlet vanes.	Yes No
12.1.3	The Code of Record, if other than ASME *BPVC*, has been defined.	Yes No
12.1.3	The piping code breaks have been defined: ASME *BPVC* Section I to ASME B31.1 or ASME B31.3	Yes No
12.1.3	The design margin to apply to the maximum piping metal temperature has been specified.	Yes No
12.1.3	Corrosion allowance is specified for headers and piping external to the boiler.	__________ __________
12.1.3	Type of piping terminal connections (welded or flanged)	__________
12.1.3	Low-point drains and high-point vents required?	Yes No
12.2.4	Circulation calculations (complete with design criteria and diagram for each circuit) are required? Define the required conditions for the calculations: — load as a percent of MCR and circulation ratio.	Yes No __________
13.4.1 d)	Start-up vents (“sky valves”) on steam outlet headers are required.	Yes No
13.4.2 c)	The design pressure for valve body assemblies has been specified.	Yes No
13.4.2 d)	Valve bodies shall be in accordance with API 553.	Yes No
13.4.4 a)	The ambient temperature range for the solenoid valves and explosion proof construction has been specified.	Yes No
14.2.1	Sootblower operation has been defined as automatic, sequential, etc.	Yes No
15.1	Structural design code.	__________
15.1	Top surface of boiler designed for walking/access?	Yes No

Subsection	Item	Requirement	
15.2	Platform widths are specified.	Yes	No
15.2	Platform decking shall have a minimum thickness of 6 mm ($^{1}/_{4}$ in.) checkered plate or 25 mm × 5 mm (1 in. × $^{3}/_{16}$ in.) open grating, unless otherwise specified. ____	Yes	No
15.2	Side step-off ladders are preferred. Step-through ladders are acceptable.	Yes Yes	No No
15.2	Walkway obstructions are permitted.	Yes	No
16	Additional connections to meet applicable governmental or local environmental requirements are required: — flue gas sampling connections.	 Yes	 No
17	Purchaser's approval of the company and individuals providing the CFD analyses is required.	Yes	No
D.5	Testing procedures and protocols for load rate changes and turndown have been established.	Yes	No
F.1.5	Tagging and labeling system to identify equipment and materials has been provided.	Yes	No
F.5.1	Dry storage practices are to be applied.	Yes	No
F.9.1	Pneumatic testing or halide leak testing may be used instead of normal hydrotesting.	Yes	No
F.9.1	Piping may be pressure tested by an initial service test (waive hydrotest).	Yes	No

Purchaser's Checklist (Part 2)

This supplemental checklist also may be used to further indicate the purchaser's specific requirements where the RP does not define a choice is required.

These items are NOT indicated by a bullet (•) in the RP.

Subsection	Item	Requirement
General item	List of sub-suppliers required?	Yes No
	Will there be another source of steam (additional boiler) in case this boiler is unable to operate?	Yes No
	Drum thickness calculations required?	Yes No
	Number of copies of referenced drawings and data required.	__________ __________
	As-built data sheets and drawings required?	Yes No
4.2.2.8	What type of spray system will be used for steam temperature control? — If steam is sent to a turbine, then an attemperation system should be used. — If saturated steam is to be used for process (non-turbine), then a desuperheating system may be used. — If the temperature and pressure of the steam are both reduced (let down), then a steam conditioning spray system may be used.	__________
4.2.3.2	Electric or pneumatic damper actuator supply?	__________
4.2.3.2	Location of control dampers and position on failure (POF): ____________________ ____________________ ____________________ ____________________	POF Open Close Open Close Open Close Open Close
4.10.2 and Annex D	Should ASME *Performance Test Code* 4.1 (older) or 4 be used to evaluate the boiler performance?	Yes No
4.10.5	Noise data sheets required?	Yes No
5.1.6 and 5.2.5	Water washing required? — radiant section, — convection section.	Yes No Yes No
5.3.3.1	Acceptable extended surface type: — studs, — solid fins, — segmented fins.	Yes No Yes No Yes No __________
5.3 and 14.2	Are fins permitted on the economizer tubes? — If fins are used, the number of sootblowers and their orientation should be carefully considered. — Sootblowers should be perpendicular to the economizer tubes.	Yes No
5.4.3.1	Radiography of critical sections required?	Yes No
6	Minimum main fuel rate during burner light-off.	__________
6	On-stream removal of liquid fuel guns is required?	Yes No

Subsection	Item	Requirement
6.1 and 7.5.2.2 q)	Applicable local rules and regulations.	___________ ___________
6.3 and Annex H	Burner shop test required? Requirements: ____	Yes No
6.5	Single burner with multiple guns acceptable?	Yes No
7.3.2.6	Tube skin thermocouples required?	Yes No
8.3	Electrical-area classification for boiler equipment/system.	___________ ___________
8.3	Electrical-area classification for fuel train and burner front components (if different).	___________ ___________
8	Corrosion allowance required for fan scroll and housing?	Yes No
8	Fan blade design.	___________ ___________
8	Corrosion-resistant shaft sleeves required for fans?	Yes No
8	Rotor response analysis required? To be confirmed by test-stand data?	Yes No Yes No
8	Corrosive agents in the flue gas or environment affecting fan materials selection.	___________ ___________
8	Alternative notch-toughness requirements for fans.	___________
8	API 560: — accessories to be supplied by fan vendor.	___________ ___________
8	Fan vendor to state maximum expected leakage through closed dampers and vanes?	Yes No
8 and 16	Type of insulation and jacketing (fan and ductwork).	___________ ___________
8	Nondestructive examination (fan fabrication).	___________
8	Shop fit-up and assembly of fan, drivers, and other auxiliaries required prior to shipment?	Yes No
8	Fan testing requirements. Mechanical run test required? Hardness testing required for fan?	___________ Yes No Yes No
14.2	Sootblowers to be provided?	Yes No
14.2	Space required for future sootblowers?	Yes No
14.2	Acceptable sootblower type: — retractable, — rotary. Sootblower media, if other than steam?	 Yes No Yes No ___________
15	Fireproofing required?	Yes No

Subsection	Item	Requirement
15	Galvanizing of handrails, etc.? Bolt protection: — galvanizing, — zinc-coating.	Yes No Yes No Yes No
16	Codes for stacks, ducts, and breeching or methods in API 560 to be used?	____________ Yes No
16	360 stack platform?	Yes No
16	Single lift stack design required?	Yes No
16	Bolting permitted for stack assembly?	Yes No
16	Acceptable aerodynamic devices: — helical strakes, — vertical strakes, — staggered vertical plates.	 Yes No Yes No Yes No
16	Pneumatic testing of ductwork required?	Yes No
16	Will the inside of the ductwork between the boiler and the economizer be refractory lined? If so, the refractory in this area should be specified.	Yes No ____________
16	Corrosion allowance (fan silencer and inlet duct).	____________
F.1	Protective coating of casing, backup insulation.	____________
Annex G	Site receiving and handling limitations. ____________________ ____________________	Yes No
Annex G	Shipping preparation requirements.	____________ ____________
Annex G	Export preparation and protection (crating). Requirements: ____________________ ____________________ ____________________	Yes No
Annex G	Long-term storage preparation required? Requirements: ____________________ ____________________ ____________________	Yes No
Annex G	Equipment to be prepared for six months of outdoor storage?	Yes No
Annex H	Pre-inspection meetings required prior to the start of fabrication?	Yes No
Annex H	Positive materials identification (PMI) required? Requirements: ____________________ ____________________ ____________________	Yes No

Annex C
(informative)

Air Preheat Systems for Boilers

API 560, Annex F is the primary source of the following description. Selected excerpts from the standard are included in this section for illustration purposes only.

API 560, Annex F is a comprehensive document covering APH design considerations, selection guidelines, safety and operations and maintenance considerations, performance guidelines, ductwork design and analysis, environmental impact, preparing an enquiry, and flue gas dew point considerations. While Annex F is a portion of API 560, Annex F's size is larger than many API standards.

An industrial fired boiler's APH system increases its thermal efficiency and/or enhances combustion of heavy liquid fuels. The economics of air preheating should be compared with other forms of flue-gas heat recovery. APH systems become more profitable with increasing fuel costs, with increasing process inlet temperature (i.e. higher stack flue-gas temperature), and with increasing fired duty. An APH system economic analysis should account for the system's capital costs, operating costs, maintenance costs, fuel savings, and the value (if any) of increased capacity.

In addition to economics, an APH system's impact on a boiler's operations and maintenance should also be considered. Air preheat systems impact boiler operations in several ways:

a) reduced fuel consumption,

b) reduced oil-burner fouling,

c) more complete combustion of difficult fuels,

d) increased NOx production (resulting from higher flame temperatures),

e) increased risk of corrosion of flue-gas wetted components (APH exchanger and downstream components),

f) increased maintenance requirements for mechanical equipment,

g) increased potential for acid-mist stack plume (if fuel sulfur content is high), and

h) reduced stack gas effluent velocity and dispersion.

Recuperative, regenerative, or heat-pipe preheaters (exchangers) transfer heat from the outgoing flue gas to the incoming combustion air, increasing air temperature to the burners.

a) The recuperative type is similar in principle to a conventional heat exchanger with the hot flue gases on one side of the heat transfer surface and the cool air on the other side. A recuperative APH has separate passages for the flue gas and the air. Heat flows from the hot flue-gas stream, through the preheater-passage wall and into the cold combustion-air stream. The configuration is typically in the form of a tubular or plate heat exchanger in which the passages are formed by tubes, plates, or a combination of tubes and plates, clamped together in a casing. Because the recuperative-exchanger cold-end surfaces are the coolest flue-gas-wetted surfaces, the surfaces downstream of the exchanger typically remain above the dew point if the exchanger's cold-end surfaces are maintained above the dew point.

b) A regenerative APH contains a matrix of metal or refractory elements (which may be stationary or moving) that transfer heat from the hot flue-gas stream to the cold combustion-air stream. For fired-boiler applications:

1) a regenerative APH has the heat-absorbing elements housed in a rotating wheel. The elements are alternately heated in the outgoing flue gas and cooled in the incoming combustion air;

2) this metal absorbs heat as it rotates through the flue-gas compartment of its housing and gives up heat as it rotates through the air compartment. The heat transfer wheel is rotated at approximately 3 rpm by driving a motor through a reduction gear. Diaphragms and seals divide the unit lengthwise to separate the hot flue gases from the air, which flow through the preheater in opposite directions;

3) the heat-transfer surfaces of a regenerative air-preheat exchanger are not required to serve as pressure parts confining a fluid and are designed to tolerate moderate corrosion. As a result, regenerative air-preheater exchangers can operate at lower metal temperatures than most other types of APHs. However, it is necessary to consider the effects on downstream equipment of the inherent air leakage and the periodic removal of acidic soot particles during sootblowing.

c) A heat-pipe APH is an indirect type preheater that uses a vaporizing/condensing fluid to transfer heat between the flue gas and the air. A number of sealed pipes containing that heat-transfer fluid vaporizes in the hot ends of the tubes (in the flue-gas stream) and condenses in the cold ends of the tubes (in the air stream). Heat-pipe APHs are not commonly used in industrial fired boilers in refineries and petrochemical plants.

Air leakage into the lower-pressure flue-gas stream is a potential problem with most preheater (APH exchanger) designs. Although most exchanger designs provide design leakage rates of less than 1.0 %, some regenerative exchangers have a design leakage rate of approximately 10 %. Furthermore, leakage rates in excess of 20 % are possible with poorly maintained regenerative exchangers.

Annex D
(informative)

Performance Measurement

D.1 Thermal

For thermal performance measurement, the method and testing is defined in ASME *PTC* 4.

D.2 Steam Purity

For steam purity testing, please refer to ASME *PTC* 19.11.

D.3 Emissions

For test methods for air emissions, please refer to U.S. EPA 40 *CFR* Parts 60, 61, and 63.

For NOx—Method 7.

For SOx—Method 6.

For particulate matter—Method 5.

For visual opacity—Method 9.

For CO—Method 10.

For VOC—Method 1.

For metals—Method 29.

D.4 Noise

For noise testing, please refer to API 560, Annex I.

D.5 Load Change Rates and Turndown

- There are no established testing protocols for load rate changes and turndown. It is suggested that the purchaser and the vendor jointly agree on the testing procedures to measure these criteria, if required.

Turndown operation shall not create new problems at any operating load. Minimum turndown extent depends on several factors that can be interrelated. Factors include acceptable boiler circulation ratios, achieving steam superheat temperature requirements, burner stability at all potential operating conditions, and fuel types and combinations. At turndown operation new problems shall be prevented for any operating load.

Load changes by the boiler shall be kept within acceptable safe parameters and meet steam system reliability objectives, as defined by the dynamic simulation.

Annex E
(informative)

Emission Controls

E.1 General

Environmental regulations often require controlling pollutant emissions from industrial boilers. These regulations frequently limit NOx, SOx, particulate emissions, and occasionally CO and mercury emissions. Emission concentrations can be defined on a wet or dry flue gas concentration basis. The wet concentration refers to the total flue gas including water vapor, whereas the dry flue gas concentration is obtained after removing the water vapor. Concentration expressed on a dry flue gas basis is thus higher than on a wet flue gas basis.

Section 6.5 discusses the various types of fuels combusted in industrial boilers. NOx and CO are usually the only pollutants of concern when burning only gaseous fuels. NOx, CO, SOx, and particulates are a concern when burning liquid fuels. Emissions from a CO boiler or waste heat boiler after a FCCU or RCCU require special consideration due to the fuel combusted and components in the vapor entering the boiler.

It is typically more effective and less expensive to prevent these components from forming rather than removing them once formed.

E.2 Combustion

E.2.1 General

The primary emission that has driven burner design has been the control of NOx (oxides of nitrogen) that are produced by the high temperature oxidation of atmospheric nitrogen (thermal NOx), the oxidation of any nitrogen chemically bound to the fuel (fuel NOx), and through rapid chemical reactions in fuel-rich zones (prompt NOx). Most NOx is comprised of NO when it exits the boiler stack (about 95 %), with some amount being NO_2 (e.g. 5 %) and trace amounts of N_2O.

Secondary emissions of concern are products of incomplete combustion such as CO and UBHCs. Many of the combustion techniques utilized to lower NOx can increase CO and UBHC, so it is often required to find the optimum point at which all of the emissions are minimized. There are other emissions that are dependent on the composition of the fuel, such as SOx (oxides of sulfur), particulate matter (PM), and heavy metals, such as mercury. In general, the composition of the fuel being burned directly corresponds to these emissions and any reduction of these emissions will involve either fuel switching or back-end cleanup equipment.

Combustion control techniques reduce the rate of NOx emission by limiting the amount of NOx formation during the combustion process. This is typically accomplished by lowering flame temperatures to reduce thermal NOx and minimizing the conversion of any fuel bound nitrogen to reduce fuel NOx. Since prompt NOx compromises a very small portion of the total NOx formed, only 10 % to 20 %, it is not typically targeted, unless NOx levels of less than 20 ppm are required. Combustion control techniques are more economical than post-combustion flue gas NOx removal methods and are frequently the primary control method utilized on industrial boilers requiring NOx controls.

The current trends with low NOx technologies are to design the boiler and low NOx equipment to work together to minimize emissions. This allows the NOx control technology to be specifically tailored to match the boiler's firebox design features such as shape, volume, and heat release pattern. It also ensures that any adverse effects of the low NOx technology on boiler operating parameters (turndown, capacity, efficiency, and CO levels) can be addressed and minimized. This process is generally accomplished by direct and frequent communication between the burner vendor and the boiler vendor during the design process to ensure maximum equipment compatibility.

When selecting NOx reduction techniques, Table E.1 provides guidance on technology selection depending on the application. When using the chart it shall first be determined if the fuel contains significant fuel bound nitrogen. Fuel NOx is the primary source of NOx emissions when firing most oils, as heavier grades of oil typically have a high quantity of fuel bound nitrogen and produce high fuel NOx. For light oils, having perhaps 0.02 % by weight of fuel bound nitrogen, the fuel NOx may represent 25 % of the total NOx produced. For this fuel the use of NOx reduction technology that addresses both fuel and thermal NOx is often selected. For heavy oils, having perhaps 0.30 % by weight of fuel bound nitrogen, the fuel NOx may represent 70 % of the total NOx produced. In this case a technique that addresses fuel NOx is most important. Most gaseous fuels do not have any fuel bound nitrogen and produce no fuel NOx; therefore, techniques that are most affective against thermal NOx are most important.

NOTE Some gaseous fuels do contain components with bound nitrogen, such as NH_3, which produce fuel NOx. Likewise, there are some liquid fuels that contain no fuel bound nitrogen and produce no fuel NOx. Evaluating the fuels used and their potential for fuel NOx versus thermal NOx production will result in the most effective technique or combination of techniques to apply.

Table E.1—Relative Effectiveness of NOx Reduction Techniques

Technique	Fuel NOx	Thermal NOx
Air staging	Excellent	Good
Fuel staging or biasing	Poor	Excellent
Flue gas recirculation	Fair to Poor	Excellent
Low excess air	Good	Good
Fuel re-burn	Excellent	Excellent
Water or steam injection	Fair to Poor	Excellent

E.2.2 Low Excess Air Firing

As a safety factor to ensure complete combustion, boilers are fired with excess air. One of the factors influencing NOx formation in a boiler is the excess air levels. For non-premix/rapid mix burners, high excess air levels (>10 %) may result in increased NOx formation because the excess oxygen in the combustion air entering the flame will combine to form thermal NOx. LEA firing involves limiting the amount of excess air that is entering the combustion process in order to limit the amount of extra oxygen that enters the flame. Limiting the amount of excess air entering a flame is accomplished through burner design and can be optimized through the use of oxygen trim controls. LEA firing can be used on most boilers and generally results in overall NOx reductions of 10 % to 20 % when firing natural gas. The added benefit to LEA firing is that boiler efficiency is typically increased by ~0.5 % per 5 % reduction in excess air, resulting in the economic benefit of reduced fuel usage. Excess air levels are typically reduced until the point at which CO emissions begin to climb above acceptable levels. Studies have shown that the most efficient boiler operation in terms of fuel usage and parasitic power occurs at a CO emission rate of 400 ppmvd. This has been proven to be the point at which over all fuel and energy usage is optimized and has thus been set as the maximum CO emission rate by the U.S. EPA.

Since the boiler will be operating closer to the point of maximum allowable CO levels, the control system and control devices need to be sufficient to maintain fuel-air ratios close to design set points. Boilers with wide or rapid load swings, or where fuel composition is highly variable, are limited in operation at LEA. LEA operation is better suited to base loaded boilers with consistent fuel composition. It should be noted that this method only moves the operating point along CO/NOx curve such that lower NOx is traded for increased CO. This is in contrast to the other methods discussed in this section where the entire CO/NOx curve is shifted lower. Staging methods (fuel/air OFA, etc.) can cause a shift along the curve and may require increased excess air. Figure E.1 illustrates the impact of LEA operation versus other NOx reduction techniques on the balance between NOx and CO productions.

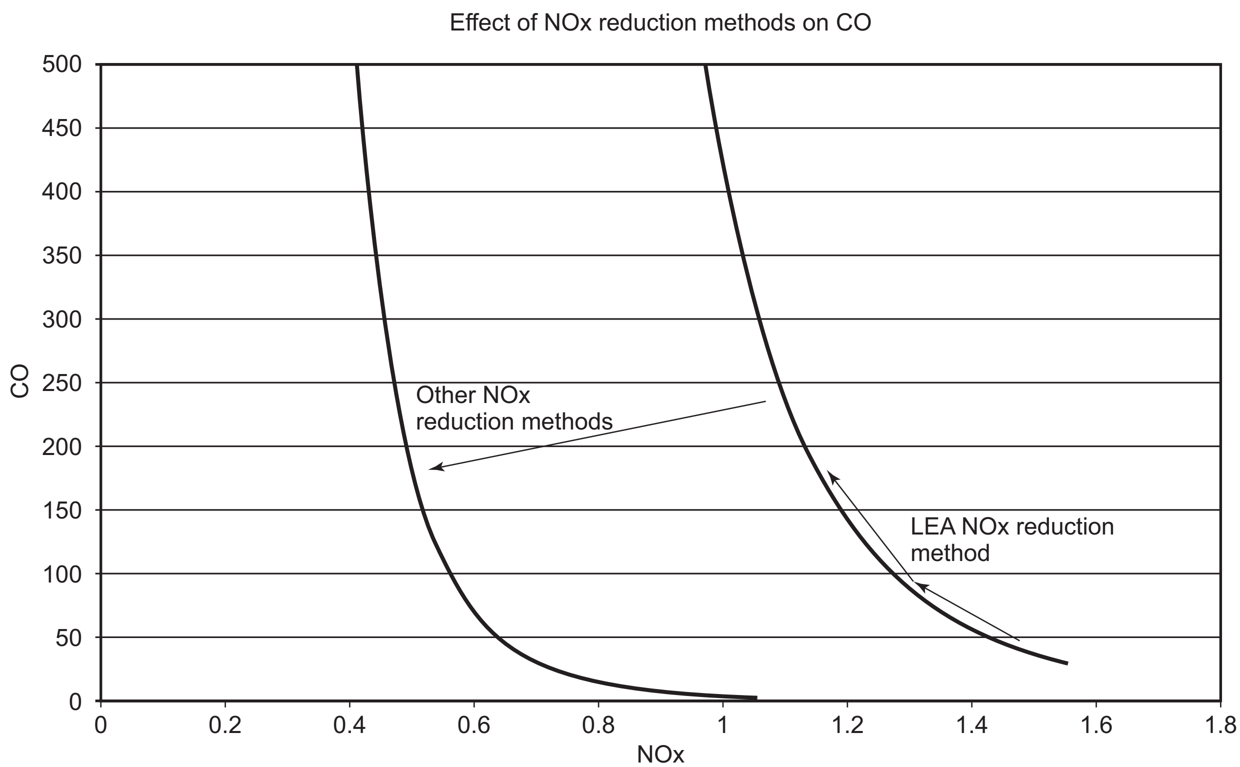

Figure E.1—Illustration of Lean Excess Air on Boiler NOx Production

E.2.3 Fuel/Air Staging or Biasing

Fuel/air staging, or biasing, can be accomplished in many ways on a multi-burner system with more than one row of burners. It can be accomplished by making the lower burner row fire fuel rich and the upper burner row fire fuel lean. Depending on the proximity of the boiler "nose" to the top row of burners, NOx reductions of up to 20 % to 25 % can be realized with this method on either oil or gas firing. If the boiler nose is well above the top burner row, there will be plenty of burnout time for the unburned fuel from the lower burners to mix and combust with the excess air from the upper burners and the full NOx reduction effect from this method can be realized. If the boiler nose is close to the top burner row, there will be reduced, and possibly insufficient, burnout time. This may limit the degree to which the lower burners can be made fuel rich. Little to no NOx reduction benefit will be realized by implementing this method in this situation.

E.2.4 Flue Gas Recirculation in Air

For gaseous fuel firing, external FGR, either in the air or the fuel, is typically the most cost effective method of reducing NOx emissions from industrial boilers. External FGR was also one of the first methods of NOx reduction employed. When using FGR, a portion of the stack gases are returned and mixed with the combustion air to the burner. This adds mass flow into the combustion zone across which the heat release is distributed, thereby lowering the peak and average flame temperature and accompanying thermal NOx formation. The introduction of FGR into the combustion air increases the overall mass of the reactants in the combustion process. The fact that the flue gases being returned also have very low oxygen levels, typically 2 % to 4 %, result in a lowering of the volumetric oxygen concentration entering the combustion zone, which also helps to retard NOx formation by limiting oxygen availability.

Since FGR primarily reduces the formation of thermal NOx, its effect is greater on gaseous fuels where most of the NOx formed comes from the thermal route, than on liquid fuels where a larger portion of the NOx comes from fuel bound nitrogen.

The flue gases can be delivered to the burner combustion air supply either through the use of a dedicated flue gas fan (forced FGR), or it can be inducted into the inlet of the combustion air fan through the use of an inlet mixing box (induced FGR). Forced FGR may be beneficial for units that burn high sulfur fuels to avoid corrosion of the fresh air FD fan and inlet duct. When the recirculated hot flue gases mix with cooler combustion air, moisture droplets may form. These droplets may contain high concentrations of sulfuric acid and result in corrosion of the burner and combustion air systems. When mixed, it is desired to keep the fresh air and recirculated flue gas mixture above the acid dew point temperature. High concentrations of sulfuric acid result in corrosion of the burner and combustion air systems.

FGR has been added to many new and existing burners, with NOx reduction ranging from 20 % to 85 % depending on the amount added, the fuel being fired, and the initial NOx level. The limit of NOx reduction varies for different fuels; up to 80 % to 85 % for natural gas and other gaseous fuels, 30 % to 40 % for light distillate oils (low fuel bound nitrogen), and 20 % to 25 % for standard heavy fuel oils (higher fuel bound nitrogen).

The drawbacks of just adding FGR to some existing burners is that older burners can require very high levels of flue gases to reduce NOx emissions to acceptable levels, and these high rates of FGR, typically over 25 %, can decrease the flame temperature to the point where burner operation becomes unreliable. The added air flow resulting from the addition of FGR increases fan load and power requirements, and a new fan may be required.

E.2.5 Flue Gas Recirculation in Fuel

An alternate method of using flue gases for NOx reduction, available when firing gaseous fuel, is for the flue gas to be mixed with the fuel before introduction to the burner. This is called fuel induced recirculation (FIR). In this design fuel pressure is used to inspirate flue gases from the boiler exhaust to each burner and mix them into the gaseous fuel prior to injection into the combustion zone. To provide sufficient motive force, higher fuel gas supply pressures are usually required to induce sufficient flue gases. The mixture of fuel and flue gas results in a diluted fuel, similar to a low Btu fuel gas, which generates lower NOx emissions. Since the energy of the fuel gas provides the motive force for inducing and mixing the flue gases, the fan horsepower impacts of this method of recirculation are much lower than the methods used to mix flue gases with air. This method provides excellent results when applied to non-staged burners where the burner design does not rely on fuel jet velocity for NOx reduction. With a staged burner the resulting low gas pressure at the firing end of the spuds can negate the staging effects of the burner design, giving little NOx benefit over the original configuration.

E.2.6 Firebox Gas Recirculation (Internal FGR)

An alternative to external FGR is to recirculate the gases directly inside the firebox. The advantage of this method is that it does not require external FGR system, resulting in reduced cost. However, the applicability and performance of internal FGR may be limited by firebox temperatures and interaction between neighboring flames. Furnace gases are at a much greater temperature, which makes them less effective at NOx reduction and makes the induction port sizes large for the amount of flow induced, and can require special metallurgy for the components in contact with them to prevent degradation due to the heat.

E.2.7 Low NOx Burners—Staged Air and Staged Fuel

The first low NOx burners were based on air staging. This concept consists in separating the total combustion air flow in two or more streams in order to reduce the peak flame temperature. Air staging is also particularly beneficial for fuel with fuel-bound nitrogen as the fuel-rich primary combustion zone reduces the conversion of nitrogen to NOx.

The burner design provides for internal staging of the flame to achieve reductions of NOx emissions while maintaining a stable flame. Staging of the air into the combustion zone serves to slow down the combustion process and separate the flame into different zones, some that operate fuel rich and some that operate fuel lean. The fuel-rich and fuel-lean zones both combust at lower peak temperatures than would a uniform fuel-air mixture, resulting in lower thermal NOx formation. The combustion products from these two zones then combine to complete the combustion process and result in the completed oxidation of the fuel. By creating a fuel-rich zone in the front part of the flame, they can also reduce the conversion of fuel bound nitrogen to NOx and thereby lower fuel NOx formation as well.

The delayed mixing of fuel and air also leads to increase in flame lengths, and staged burners can have flames that are 25 % to 50 % longer than conventional burners of the same heat input. This also helps to reduce NOx by subjecting the flame body to more of the firebox water-wall surface area, which also helps to draw heat from the combustion process and cool the flame. However, increasing the flame length has to be carefully balanced with available firebox depth, otherwise flame impingement on boiler furnace walls can occur. Flame impingement will result in unburned fuel being emitted from the boilers in the form of both hydrocarbon emissions and CO, which is both an emissions and an efficiency problem, and can be detrimental to boiler tube life.

In an effort to further reduce NOx emissions while firing gaseous fuels, some burners will employ fuel staging, whereby a portion of the fuel, anywhere from 50 % to 90 %, is injected directly into the furnace outside of the air register. This process relies on the use of a highly stable center or core flame, which helps to create and maintain a fuel-lean primary combustion zone at the burner front. As all of the combustion air is introduced through the burner air throat along with a relatively small portion of the gaseous fuel, the base of the burner operates at very high excess air levels. Without the use of the center-fired gas flame to provide a stable ignition source, the high excess air levels found in the primary combustion zone will not be able to reliably sustain stable combustion. By operating fuel lean, both thermal NOx and prompt NOx formation is reduced in this zone.

The staged flames are formed as the gaseous fuel jets enter into the furnace and are ignited by the hot combustion products from the center flame. The injectors are located at a set distance from the center flame and may be called “secondary injectors.” This allows the gas jets to entrain additional amounts of inert high temperature firebox gases prior to entering the combustion zone. The diluted fuel and furnace gas mixture limits the temperature rise resulting from the combustion process, dramatically reducing the formation of thermal NOx. This outer gas injector fuel consumes the excess oxygen left over from the fuel-lean combustion zone, which has also generated its own combustion products. This method of internal furnace gas entrainment, combined with the fuel-lean primary zone combustion products, results in a secondary combustion zone that is equivalent to a burner operating with high levels of FGR.

E.2.8 Additional Air Staging Techniques

In some boilers, particularly those equipped with multiple burners, the use of additional techniques to implement air staging may be employed. One commonly used method is to utilize a series of air ports to deliver a portion of the air into the furnace. In a horizontally fired burner application these ports may be arranged in a concentric ring around the burner throat or can be located in the side walls of the boiler some length down the furnace and are typically called “NOx ports.” In multiple burner applications with vertical flow path boilers, the ports typically take the form of a row of ports above the top row of burners, called “overfire air,” or below the bottom row of burners, called “underfire air.” The purpose of these ports is to divert a portion of the combustion air, typically 10 % to 25 %, away from the burners and into the furnace. This causes the burners’ primary flame zone to operate fuel rich, reducing flame temperature and thermal NOx. This fuel-rich operation will also reduce the conversion of fuel bound nitrogen to fuel NOx.

The use of any type of air port requires that the air injected through the ports mix with the fuel-rich combustion products from the burners to complete the burnout of any CO and hydrocarbons before exiting the furnace. The degree to which this type of air staging can be employed is dependent of the furnace volume and residence time for the mixing to occur. The penetration and mixing of the air from the ports is an important design condition for the success of these systems and is commonly modeled using physical or CFD techniques to ensure proper system design.

With adequate vertical distance between the top burner level and the boiler nose, NOx reductions of up to 30 % to 40 % can be realized with this method on either oil or gas firing. However, as with fuel/air biasing, if the top burner elevation is close to the boiler nose elevation this method may not allow much NOx reduction.

In multiple burner installations this effect can also be achieved by biasing the fuel to some burners. This causes some burners to operate fuel rich and others to operate fuel lean. This may include shutting off the fuel completely to one or more burners, which is called “Burners Out of Service (BOOS)”. The optimum amount and pattern of biasing or BOOS is often boiler dependent, with the best NOx reduction results found through a series of tests during commissioning.

E.2.9 Steam and Water Injection

Another method that has been applied to reduce NOx emissions from either gas or liquid fuel combustion has been the use of steam or water injection. Steam or water act to absorb heat from the combustion process and reduce thermal NOx formation. Since steam is available at high pressures, the energy of the steam jets can also be used as a method to increase fuel-air mixing within the burner and to entrain furnace gases into the flame front. However, the injection of steam always comes with the additional boiler operating costs associated with generating the steam for injection, unless a source of waste steam is available for use. Water treatment costs can also represent a significant impact in cases where high levels of chemical treatment of BFW are necessary. The use of water injection, in place of steam, also has operational costs associated, both with the power required for pumping and with the latent heat of vaporization that cannot be recovered by the boiler and, therefore, decreases thermal efficiency of the unit.

E.2.10 Reburning

In boilers with large volume furnaces, one way to reduce NOx formed by the burners is to inject a portion of the fuel (typically 10 % to 20 %) into the combustion products before they exit the radiant section of the boiler. This fuel will not be able to find sufficient available oxygen to react with, so it will scavenge the oxygen from any NOx that it interacts with. This technique requires injection, mixing, and sufficient residence time for the scavenging to occur. Additional air shall then be injected and mixed with the combustion products to allow any remaining fuel and CO to be completely oxidized. Both of these steps shall be accomplished before the gases exit the radiant section of the boiler, or else high CO and/or hydrocarbon emissions can result. The penetration and mixing of the fuel injection and the air injection is a critical design condition for the success of these systems and is commonly modeled using physical or CFD techniques to ensure proper system design.

E.2.11 Boiler Effects

Since many of the NOx control techniques rely on reduction of flame temperature and control of fuel and air, the effect of the boiler itself should also be considered on these parameters. Anything that adds heat to the combustion zone, such as preheating combustion air, will increase thermal NOx. Replacing APHs with economizers to preheat feedwater will result in NOx reduction without efficiency impact.

The size and configuration of the combustion chamber will affect how much staging of fuel or air can be applied, and to use these techniques to their fullest extent requires a larger furnace section. All parts of the boiler furnace that are covered in refractory will re-radiate heat back into the combustion zone and increase NOx. Combustion zone temperatures can also be impacted by the fouling of the inside or outside of radiant section tubes. As these tubes foul, it reduces their ability to pull heat out of the flame zone and increases temperatures and thermal NOx.

The control of fuel-air ratio has a large effect on emissions reduction and issues like tramp air or not operating at optimum excess air levels due to poor controls will impair the effectiveness of these techniques.

E.2.12 Fuel Effects

Fuel affects the formation of NOx emissions in two major ways—first it defines the temperature at which the combustion process occurs, affecting thermal NOx, and secondly, any bound nitrogen will generate fuel NOx. Fuels components with higher flame temperatures, such as hydrogen, will dramatically increase thermal NOx formation. Likewise, the firing of heavier grades of residual oil will dramatically increase fuel NOx formation. When firing fuel oils, NOx formed by fuel-bound nitrogen can account for 50 % to 70 % of the total NOx produced. One method to reduce NOx levels from boilers firing distillate oils is through the use of low nitrogen fuel oil. Low nitrogen oils, such as ultralow sulfur diesel or pyrolysis fuel oil, can contain 1/15th to 1/20th the fuel-bound nitrogen (less than 0.001 % by weight fuel-bound nitrogen) as compared to standard No. 2 oil. When low nitrogen containing oil is fired in boilers utilizing FGR, NOx reductions of 60 % to 70 % over NOx emissions from standard No. 2 oils have been achieved.

E.3 Post-combustion

E.3.1 General

Due to environmental regulations that restrict emissions from industrial boilers, pollutants formed during the combustion process may be required to be reduced before leaving the boiler stack. These emissions include NOx, CO, and potentially SOx and particulates such as mercury. Emission limits can be defined on a wet or dry by the regulatory agency. Pollutant limits measured on a wet basis can be easier to attain, as the water vapor formed by combustion lowers the apparent concentration of the pollutant. The dry basis includes the concentration of the pollutant in the flue gas without water vapor as if the water had been condensed out. Since there is less total gas in the dry basis, the concentration of NOx molecules on a dry basis is higher than that measured on a wet basis.

The formation of NOx and CO can be reduced by using specific burner designs. Care shall be taken as some burner designs minimize NOx, but increase CO production. However, tighter regulations and/or other unusual circumstances, such as use of liquid fuels, leads to the need for post-combustion methods to reduce pollutants. These methods are available to reduce pollutants and most are proven and very effective. These methods include SCR, selective non-catalytic reduction (SNCR), electrostatic precipitator (ESP), wet electrostatic precipitator (WESP), baghouse, and wet and dry scrubbers.

E.3.2 NOx Removal

SCR and SNCR are methods used to remove NOx by injecting NH_3 or other reducing agents into the combustion gases (in SNCR) or into the combustion gases in front of a catalyst bed (in SCR) to remove oxygen from the NOx molecule resulting in elemental nitrogen (N_2) and water. This annex will only briefly discuss these methods; API 536 reviews these methods in detail.

SCR systems can provide NOx reductions in the range from 80 % to 95 %, depending on the application and the local requirements. In the last 20 years SCR systems have been one of the predominant solutions to reduce the NOx emissions from refineries and petrochemical plants. Effective mixing between the reducing agent and the flue gases keeps NH_3 emissions generally below 10 mg/Nm^3.

SNCR, on the other hand, has been much less used for the following reasons.

a) The SNCR NOx reduction process requires mixing the reducing agent (urea or NH_3) with combustion products at elevated temperatures with sufficient residence time before the mixture is cooled.

b) Changes in firing rate and fouling of heat transfer surfaces affect the temperature field inside and downstream of the combustion chamber, which can reduce the effectiveness of an SNCR system.

c) Depending on thermal and geometric characteristics, the effectiveness of SNCR systems in furnaces and boilers ranges typically from 0 % to 50 %.

d) Typical NH_3 emissions of SNCR systems reach 5 mg/Nm^3 to 40 mg/Nm^3. NH_3 slip, or the loss of unreacted NH_3 with the flue gas, increases with the urea/NO molar ratio, poor mixing between the SNCR reducing agent and the combustion products, and with reaction temperatures that are too low.

e) In combustion systems with SO_2 emissions, NH_3 reacts with SO_2 and forms ammonium salts. These salts condense below 235 °C (455 °F) and can foul and corrode convection section tubes and APHs.

f) In case of impingement, NH_3 droplets can corrode the tubes in the vicinity of the NH_3 spray nozzles.

The following are the major design considerations in choosing between SNCR and SCR, and if SCR, its components.

a) Temperature where the NOx reduction will occur. This will greatly determine which method is used and if SCR, which type of catalyst will be the most effective. It will be required to make mechanical modifications to create space for the additional equipment.

b) Amount of area available for equipment and its auxiliary components, such as NH_3 storage, blowers, etc.

c) The available pressure drop at the location of NOx reduction.

d) The amount or percentage of NOx reduction required by the permit. The SNCR method is limited in reducing NOx; making SCR a requirement for greater NOx reduction. SNCR may be economic at lower NOx reduction requirements.

e) SCR systems have a lower NH_3 slip level for a given reduction in NOx when compared to SNCR. The NH_3 slip of SCR systems is typically less than 10 ppm, although much lower levels can be achieved.

f) The components in the flue gas that may damage and/or plug the catalyst in the SCR.

E.3.3 CO Removal

CO is formed during the combustion process under the following situations.

a) The temperature in the combustion zone is too low.

b) The amount of time in the combustion zone does not allow complete conversion of CO to CO_2.

c) There is insufficient air in the combustion zone.

d) The fuel and air are not mixed properly at the burner or in the combustion zone. This is more common with liquid fuels than gaseous fuels.

CO removal is typically not required on fired boilers, as proper burner design and operation will result in very little CO production. An example of a boiler design that may emit significant CO is one with a high amount of external FGR to reduce NOx. Catalytic oxidation is the most common post-combustion technique to reduce CO from flue gases.

Two applications where CO removal is typically used include CO fueled boilers and HRSGs located after gas turbines.

CO is converted to CO_2 in the presence of oxygen and a catalyst. A rare metal, such as platinum or gold, is applied to a metal or ceramic substrate. These catalysts have a wide range of operating temperature, from 150 °C to 650 °C (300 °F to 1200 °F). It can frequently be installed in the same flue gas temperature zone as an SCR. It is important for the CO catalyst (oxidation catalyst) to be in front of the SCR catalyst since the NH_3 from the SCR could damage the oxidation catalyst. The NH_3 may also be converted into NOx if oxidized by the oxidation catalyst. The oxidation catalyst can also increase the conversation of SO_2 to SO_3, with associated fouling and corrosion implications.

CO removal is less difficult than NOx removal, as a reagent is not required (unlike an SCR, which requires NH_3) and equal flow distribution across the catalyst bed is not critical. There is a pressure drop across the CO catalyst bed that shall be considered, but it is much less than that with a SCR.

Since the catalyst is usually located in a duct after the heat transfer area and does not have auxiliary components, the amount of space required is minimal. A concern in a retrofit application is having space in the duct either before or after the economizer.

Much like SCR catalyst, damage of the catalyst from flue gas components is a consideration. These components can either coat the catalyst preventing reaction from occurring or poison the catalyst making it inert. They can also plug the catalyst increasing pressure drop and reducing its effectiveness.

E.3.4 SOx Removal

E.3.4.1 General

SOx is formed whenever sulfur or components containing sulfur are present in the fuel gas or enter as part of the vapor feed. The burner combustion process does not destroy sulfur. It will oxidize sulfur to SO_2 with some SO_3 at lower temperatures, depending on the amount of excess of oxygen present. SO_3 will either exit or condense into H_2SO_4 and form a particulate.

Wet scrubbing and dry scrubbing are two common SOx removal methods available.

E.3.4.2 Wet Scrubbing

The most common method is wet scrubbing using sodium hydroxide (NaOH), which converts SO_2 to sodium sulfate, which is soluble in water and removed from the aqueous stream. Depending on which method is used to wet the flue gas in the scrubber, pressure drop can be very high and require additional force to push the flue gas through the scrubber. Plot space can be significant and shall be carefully reviewed.

Flue gas temperature is very important since the higher the entering temperature, the higher the water consumption requirement. The flue gas will be water saturated when exiting.

E.3.4.3 Dry Scrubbing

Alternatively, direct contact with dry sorbents, such as lime or limestone forming solid calcium sulfate, is another method, but rarely used on industrial boilers.

E.3.5 Particulate Removal

Particulates are formed when metals and sulfates in the fuel are liberated during combustion, liquid fuels are not properly atomized or cannot be fully atomized, or components improperly react during combustion. Particulates are solids present in what is otherwise an all vapor flue gas stream. Particulates can also enter with the incoming vapor such as FCCU and RCCU regenerator gases. The most common methods of particulate removal include a baghouse, an ESP, and a WESP. All of these methods are located after all heat transfer surfaces.

The following are considerations in selecting one of these methods.

a) The particle size and amount required to be removed is the most important decision. If larger particles in low volume are to be removed, a baghouse is a good choice due to low cost to buy and operate. If smaller particles are to be removed or a high volume of particles, an ESP would be the better choice. Very small particles, such as mercury, or sticky particles, such as silicates or sodium, would be best removed using WESP.

b) Pressure drop is generally higher with the need to remove smaller particles. Baghouses have the lowest pressure drop since surface area can be increased to reduce pressure drop at a minimal cost.

c) Operating temperature requirements would be higher with an ESP compared to a baghouse. Baghouses are limited by the bags themselves to 190 °C to 205 °C (375 °F to 400 °F). These temperatures are compatible with most industrial boiler applications. A WESP can operate at higher temperatures since water can be used to quench the temperature and saturate.

Annex F
(informative)

Procedures

F.1 Shipping Preparation

F.1.1 Introduction

This section addresses the preparation of the boiler for shipping and short-term on-site storage, where the shipping and storage duration is not expected to exceed six months.

The boiler shall be prepared for shipping in order to:

a) minimize corrosion,

b) prevent freeze damage,

c) prevent mechanical damage,

d) prevent contamination.

F.1.2 Preparation for Shipment

The vendor shall be solely responsible for preparing equipment for shipment and ensuring its shipment in good condition.

F.1.3 Bill of Materials

A separate copy of the MSDS forms, as applicable, and bill of materials in each container shall be submitted to the purchaser's representative (e.g. construction manager or other) prior to shipment.

F.1.4 Packing

All boiler system components and equipment shall be packed, securely anchored (skid-mounted when required), and satisfactorily protected for their respective shipment methods.

All separate, loose, and spare parts shall be boxed, individually protected as required, and packed in plywood containers for shipment.

Refractory shipped loose for field installation shall be prepared for shipment in the following manner:

a) castable refractory shall be palletized, shrink wrapped in plastic, and encased in waterproof cardboard;

b) firebrick, burner tiles, and pre-formed shapes shall be protected against mechanical damage, palletized, and wrapped in plastic;

c) fiber refractory shall be palletized and shrink wrapped in plastic.

For components with pre-installed castable refractory sections, to minimize the tendency for alkali hydrolysis to occur the sections shall be prepared for shipment in such a way as to allow good air circulation during the entire shipping and storage periods. The use of shrink wrap (air-tight packaging) coverings shall be avoided.

F.1.5 Tagging

- The vendor and purchaser shall agree on a tagging and labeling system to identify equipment and materials. An example of typical information required is as follows.
- Each item shall be identified with its purchase order (P.O.) number and item number. Tags shall be stainless steel and impression stamped as follows.

P.O. No.______________________________

P.O. Item No.__________________________

Equipment Tag No. _____________________

- Tags shall be attached to the equipment or material with stainless steel wire. This tagging shall be in addition to the equipment nameplates. Equipment and material shipped in fully enclosed containers shall also include the above information marked on the outside of the containers.

Major equipment assemblies shall have the purchase order number, equipment tag number, and shipping weight stenciled on the assembly. All systems, components, and materials to be assembled in the field shall have the erection or assembly mark identification codes, as indicated on the vendor's erection and detail drawings, indelibly marked on the piece. Equipment containing insulating oils, antifreeze solutions, or other fluids shall be suitably tagged at openings to indicate the nature of the contents and the required shipping and storage precautions. MSDS documentation shall be provided.

Miscellaneous parts shall be tagged or marked with the tag number of the item for which they are intended. All such parts shall be suitably boxed, firmly attached to the main item, and shipped with the unit for which they are intended. All prefabricated piping spool pieces shall be match-marked and appropriately tagged to facilitate field assembly.

F.1.6 Drainable Boilers

If the boiler is drainable, it shall be drained after hydrotest and subsequently dried to eliminate water and avoid freeze damage or corrosion. If there are low points that may retain water, then refer to the non-drainable boiler section. If the boiler components have been shop hydrotested, ensure they are adequately drained and free of water and chemicals prior to shipping.

F.1.7 Non-drainable Boilers

Boilers that cannot be completely drained shall be protected from freezing and corrosion. Water used for the final shop hydrotest shall contain antifreeze with corrosion inhibitor sufficient to protect the boiler from freezing in the coldest conditions to which the boiler may be exposed.

F.1.8 Bracing

Bracing, supports, and rigging connections shall be provided to prevent damage during shipping, lifting, and unloading.

All temporary bracing and supports shall be painted a color contrasting to the equipment assemblies and shall be appropriately tagged to facilitate proper removal in the field.

All instruments and valves, including auxiliary systems, shall be securely mounted, supported, and/or boxed to avoid damage during shipment.

Each boiler section shall be equipped with lifting lugs and structural bracing designed and positioned by the vendor to permit damage-free handling during shipment and lifting for erection.

F.1.9 Waterside Openings

The waterside openings (i.e. headers, tubes, nozzles, etc.) shall be covered to prevent the ingress of water and debris.

Flanges shall be coated with an easily removable protective coating. Flanges shall be covered to prevent mechanical damage.

F.1.10 Gas Side Openings

The gas side openings shall be covered to keep out water and debris.

F.1.11 Special Requirements on Protective Coatings/Coverings for Ocean Shipment

All exposed finished and machined surfaces, including bolts, shall be given a heavy coating of rust-inhibiting compound.

Bearings and seal assemblies shall be fully protected against the entry of moisture and dirt.

Flanged openings shall be provided with full-flange diameter protective covers. Cover material shall be metal plate with a minimum thickness of 5 mm (0.2 in.). A full-diameter gasket shall be held between the flanges by a minimum of four full-diameter bolts and nuts.

All other openings, including the ends of tubes and pipes, shall be adequately sealed for protection. Long-shank metal pipe plugs or pipe caps shall be used for all such connections. Tape and plastic plugs and caps are not acceptable. The material of the plug or cap shall be the same as that of the opening to be sealed.

Tubes shall be blown free of moisture immediately before sealing for shipment. Flanged openings shall be provided with full-flange diameter protective covers. Cover material should be 13 mm (0.5 in.) minimum thickness plywood or plastic, or 5 mm (0.2 in.) minimum thickness steel plate. A full-diameter gasket should be held between the flanges by a minimum of four full-diameter bolts and nuts. All flange gasket surfaces and ferritic tubes and extended surfaces shall be coated with a rust inhibitor.

All other openings, including the ends of tubes and pipes, shall be adequately sealed for protection. Plastic pipe caps, or equivalent, shall be used. Tape is unacceptable.

F.2 Storage Prior to Start-up

F.2.1 Introduction

This section is applicable if the total duration of the shipping and the onsite storage exceeds 1 month in humid climates and 3 months in dry climates. The selected storage method will depend on the climate and the anticipated duration of storage.

F.2.2 General Storage

The following addresses general storage requirements.

a) In humid climates, corrosion of tubes, fins, and waterside surfaces can occur much more rapidly on a boiler in storage that on an operating boiler. A stored boiler (waterside or gas side) can be protected with volatile corrosion inhibitors (VCIs). The directions of the supplier for the particular type of VCI used shall be followed. The system shall be closed to contain the VCIs. The closures should be reasonably gas tight, but need not be pressure tight.

b) Desiccant or dehumidifying systems may also be used to protect the gas side.

c) Nitrogen blanketing applies to the waterside only. Nitrogen layup requires pressure-tight closures of all openings and, depending on equipment to be stored (steam drums, economizers, etc.), may not be practical for onsite storage prior to start-up. Procedures for nitrogen layup are covered in F.5.3 of this document. Refer to the personnel protection section (F.11) for proper precautions of nitrogen purging.

F.2.3 Outdoor Storage

Outdoor storage requirements are as follows.

a) The boiler and any loose components shall be placed on blocks or timbers elevating it above ground and expected groundwater level (e.g. flood). Tarps or other protection shall be used to shelter the equipment from the weather.

b) For equipment that was shop hydrotested, ensure low-point drains have been opened to remove residual water. Antifreeze or desiccant may have to be used in a boiler with non-drainable low points for cold weather storage.

F.3 Pre-service Inspection Guidelines

F.3.1 Introduction

The entire system shall be inspected when installation of the unit is completed and before the unit is placed into operation. The inspector shall be the purchaser's representative.

F.3.2 Flue Gas Side

Flue gas side pre-service inspection requirements are as follows.

a) Expansion joints shall be inspected to verify proper installation and adequate thermal expansion.

b) Ensure flue gas paths are free from debris.

c) Conduct visual inspection for corrosion or scaling.

F.3.3 External

External pre-service inspection requirements are as follows.

a) External insulation and lagging should be complete and properly installed. Lagging shall protect the casing from corrosion caused by water seeping through the insulation. Casing plates should show minimal or no distortion.

b) Column and stiffener casing welds should show no signs of cracks.

c) Field joints should be seal welded. All field joints should be cleaned and prime painted.

d) Upon completion of the pre-service inspection, access doors should fit properly and securely and gaskets should be in good condition and properly installed. Access door gaskets can be used more than one time if they are handled properly. Doors should be bolted closed so that even pressure is put on all sealing surfaces.

e) Paint should be in good condition with no peeling or flaking. It is advisable to do any finish painting prior to start-up.

f) Foundation, anchor bolts, structural legs, base plates, grout, pillars, and fireproofing should be inspected. Ensure boiler is allowed to expand per the design.

g) Check that all personnel protection has been installed. The boiler and ducts that may be hot or uninsulated are dangerous to operating personnel.

h) All drain holes in the roof casing shall be clear and unobstructed to allow adequate draining. Ensure there are no areas in the roof where water can accumulate.

F.3.4 Tubes

Tube pre-service inspection requirements are as follows.

a) Verify the tube bank arrangement and bundle fixed points and ensure bundle is allowed to expand. Inspect external piping supports. Drain lines should be sloped in accordance with the specifications.

b) Tubes that show signs of bowing prior to start-up should be evaluated by purchaser's inspector and equipment manufacturer. The condition should be documented for future reference.

c) Extended surface (fins or studs) should be relatively undamaged. Major areas of fin damage can be straightened. If the major areas of fin damage cannot be straightened, the purchaser and manufacturer shall determine the need for repair or replacement. Fins may be left bent if only minor areas are damaged.

d) Finned tubes should be free to expand without damage to the fins.

F.3.5 Manways

Manway pre-service inspection requirements are as follows.

a) Verify the manway doors are properly aligned. The doors should be free to swing to the full closed position without force.

b) Bolts and yoke shall be in good condition. Coat bolt threads with an anti-seize compound to permit easy removal during inspection. Yokes should be free of cracks.

c) Gasket seats on the ring and door should be flat and clean before installing the gasket. The inspector shall verify the gaskets used meet specifications. The entire gasket should be contained between the flat gasket surfaces.

F.3.6 Interior Surface

Interior surface pre-service inspection requirements are as follows.

a) Inside surfaces of drums should show no signs of corrosion, erosion, or scaling. Normal mill scale and surface rusting will be removed during the chemical cleaning.

b) Ensure drums and headers are clear of debris and any object that may plug tubes or nozzles are removed.

c) Ensure all personnel have exited the boiler before start-up sequence.

F.3.7 Exterior Surface

The code stamping on the drum shall be visible. When insulation is installed over the drum heads, the stamping nameplate shall remain visible for the AI.

F.3.8 Internals (Piping and Steam Separating Equipment)

Piping and steam separating equipment pre-service inspection requirements are as follows.

a) If the internal separation equipment is removed for purposes of cleaning the system, ensure all equipment has been replaced and is securely installed.

b) Steam separating equipment shall be securely installed. The seal welding on the belly plate, cyclone baffle, and mesh box shall be free of cracks.

c) Internals should be free from mechanical damage.

d) Distribution pipes (feedwater, chemical feed, downcomers, etc.) shall be properly and securely supported and free of blockage.

e) Check the internal pipes are installed per the drawings. The pipes shall be adequately supported to resist the forces imposed by the turbulence of the water inside the drum during operation.

f) The holes in the feedwater distribution pipe should be aligned to discharge the water horizontally above the downcomers.

g) The continuous blowdown line should be installed below the LWA point with the holes facing the top of the drum.

h) The chemical feed line shall be placed to one side of the drum and the holes shall align to discharge the chemicals horizontally. Verify the chemical feed line has proper drain and vent connections.

F.3.9 Piping and Valves

Piping and valve pre-service inspection requirements are as follows.

a) Safety valves shall have proper rating, be installed on the proper equipment, and valve nameplates shall be visible for the local inspector.

b) Safety valves shall not be blocked in or isolated; there shall be neither block valves nor blinds between the safety valve and the pressure part.

c) Check that safety valve and vent discharge lines are directed away from areas accessible by operating personnel. Ensure there is no blockage or restriction in the discharge piping. All safety valve discharge drains shall be clear and unobstructed to prevent water or ice from accumulating in the piping and creating back pressure on the safety valve. Check the vent stacks from the safety valves are firmly supported and restrained. Ensure no physical interference exists between vent stacks and the valves over their entire operating envelope.

d) Check all valves are installed in the correct flow direction.

e) Ensure all orifices and flow devices are properly installed.

f) Ensure all blinds used for hydrotesting or chemical cleaning have been removed.

g) Ensure all drains and vents are free of obstructions and lines have been properly routed and supported to allow freedom for thermal growth.

h) Ensure temporary gauge glasses installed for cleaning have been replaced by the permanent gauge glasses for operation.

i) Check all bolts on flanged connections are bolted properly (torqued as per specifications).

j) Ensure all access ports and instrument test ports are properly capped. No open ports are permitted.

k) Verify that all temporary pipe supports and braces, which were installed for erection and cleaning purposes, are removed before start-up.

l) Verify that all springs and constant support hangers are properly set and any temporary blocking has been removed.

m) Confirm all silencers have been installed in their proper location.

F.3.10 Personnel Access

Personnel access pre-service inspection requirements are as follows.

a) Platforms, walkways, ladders, and stairways shall be bolted or welded to the appropriate structural members. All platforms shall be level.

b) Protective railing and toe guards shall be bolted or welded securely.

c) Elevation changes and obstructions on platforms shall be provided with adequate marking to warn personnel.

d) Cladding and insulation shall be installed sufficiently over excessively hot/cold surfaces and be without damage or deformation.

e) Confirm all ladder gates are installed properly and in all required locations.

F.4 Pre-operational Cleaning Guidelines for New Boilers

F.4.1 Introduction

Before the initial commissioning, the boiler shall be cleaned to remove debris, dirt, grease, oil, preservatives, rust inhibitors, mill scale, and flash rust present in the boiler system as a result of fabrication, shipping, storage, and construction. Pre-operational cleaning should also be considered after repairs or modifications. One should be aware that cleaning too frequently or the use of too concentrated or inadequately inhibited cleaning chemicals can lead to damage. The deaerator is excluded from these procedures.

This procedure is to be used as a guideline for a qualified boiler cleaning company. For specific guidance on cleaning parameters, cleaning chemical solutions, see Section 14.

F.4.2 Scope

The purpose of this section is to describe general guidelines for effectively cleaning the natural circulation boiler and economizer systems. These guidelines will include the following:

a) definitions;

b) system identification and isolation;

c) removal of debris prior to cleaning;

d) flushing;

e) alkaline cleaning to remove grease and oil;

f) acid cleaning, if necessary, to remove mill scale and flash rust;

g) passivation of cleaned surfaces.

Each chemical cleaning effort shall be carefully planned and executed. Detailed procedures should be written in advance of every cleaning operation. These detailed procedures should include, but not necessarily be limited to:

a) detailed schematic drawings;

b) temporary piping plans and details;

c) operational procedures for cleaning equipment;

d) contingency plans for chemical upsets;

e) water chemistry sampling and analysis procedures;

f) disposal plans for spent cleaning solution.

F.4.3 System Identification and Isolation

It is essential that each system to be cleaned be identified and the extent of cleaning be clearly defined. Schematic diagrams should be prepared to define the economizer system, boiler system, and piping to be cleaned. These schematics should identify branch lines, dead ends, bypasses, instrument connections, and parallel circuits of various sizes and configurations.

a) Temporary piping should be laid out so that all piping and equipment to be cleaned and flushed is included in the system.

b) Temporary connections shall be established in the economizer system to create a once-through system for flushing. Non-flushable areas should be minimized.

c) Spring supported piping not equipped to handle loads prior to normal operation shall be blocked to prevent spring damage during cleaning.

d) Instruments and equipment (e.g. gauge glasses, check valves, desuperheater probes) that could be damaged during the cleaning procedures should be identified and isolated or removed.

e) Bypasses should be installed around feed pumps.

f) Dead ends and bypasses should be minimized and kept as short as possible.

g) Provisions for draining or blowing down dead ends should be made where possible. Note areas that cannot be drained and plan on adjusting the final rinsing process accordingly. Consideration shall be given to branch lines and dead legs to ensure an adequately cleaned and rinsed system.

Once all temporary piping and circulation systems have been installed, the system should be hydrotested at $1^{1}/2$ times the expected cleaning pressure to identify any leaks prior to introduction of chemicals. If leaks are identified, these shall be repaired or plugged prior to introduction of chemicals.

F.4.4 Removal of Debris Prior to Cleaning

Removal of dirt and debris from the interior of the boiler prior to flushing and cleaning is essential to prevent blockage of tubes and valves.

a) Mechanically remove as much excess grease and oil as possible.

b) Large items, such as cans, wrappers, weld rods, etc., should be manually removed. Boiler drums should be vacuumed prior to cleaning and flushing.

c) The system should then be flushed with water as thoroughly as possible, to remove residual debris.

F.4.5 Flushing

The economizer and boiler systems should be flushed to remove any debris prior to the alkaline cleaning. Flushing is a filling and draining process rather than a recirculation process. Washing with high-pressure hoses can also be done.

a) Parallel flow paths should be flushed separately where possible.

b) Flushing should be done with BFW or good quality municipal water.

c) Flushing should be continued until the effluent is clear.

Flushing the economizer system should be performed periodically at the maximum permissible flow rates to promote movement of heavier materials and purge low flow areas.

During boiler cleaning, the superheater should be filled with demineralized water and back flushed periodically to prevent chemical contamination.

F.4.6 Alkaline Boilout—General [10]

The purpose of alkaline cleaning is to remove oil, grease, and preservatives that remain in the boiler after flushing—this cleaning is intended for a new boiler. The alkaline solution will also remove some silica, hydrocarbon contamination and loose deposits. Alkaline cleaning should be completed prior to acid or chelate cleaning. More aggressive alkaline solutions and higher temperatures should be considered in cases where hydrocarbon contamination is more pervasive than oil, grease, and mill scale.

The economizer and the boiler systems can be cleaned simultaneously.

Precautions to be taken during alkaline boilouts:

a) Replace drum level gauge glasses with temporary gauge glasses. The alkaline solution will damage the drum level glasses.

b) Isolate or flood the superheaters with treated high purity water to prevent alkaline solutions from contaminating the superheaters, corroding them in service. Treated, high purity water can be condensate or demineralized water treated with an amine and a volatile organic oxygen scavenger [N, N-Diethylhydroxylamine (DEHA), carbohydrazide, etc.].

c) Superheaters should be flushed with treated, high purity water after an alkaline boilout to ensure that none of the cleaning solution entered the superheaters. The spent flush water should be tested to confirm superheaters have been flushed acceptably.

It is recommended to do alkaline cleaning with an external heat source and forced circulation; however, a natural circulation boiler can be cleaned by firing the burners and operating the boiler at a pressure of approximately 175 kPa (ga) [25 psi (ga)] and allowing natural circulation to circulate the solution in the boiler. In any event, the economizer system shall have forced circulation.

When firing the boiler is not practical, an external heat source should be used. Use a temporary pump to circulate the cleaning solution through the economizer system. It is not recommended to use the condensate or feedwater pumps to circulate alkaline cleaning solutions. These pumps should be isolated.

F.4.7 Alkaline Cleaning Solution

Alkaline cleaning formulations can be based on tri-sodium phosphate, $Na3PO_4•12H_2O$, or sodium bicarbonate. These solutions provide detergency and emulsifying power similar to that of caustic solutions.

A typical alkaline solution used for cleaning is described in 14.1.1.

Use of caustic (NaOH) formulations can cause caustic stress corrosion cracking (embrittlement) and is not recommended. For further information, see 14.1.1.

The cleaning company and purchaser are responsible to verify that the cleaning solutions used are compatible with all materials they contact.

Solid chemicals shall not be added directly into the boiler drum. Chemicals should be dissolved in a separate vessel and then added to the boiler by blend-filling or injecting during circulation.

F.4.8 Procedure—Alkaline Cleaning Using External Heat Source

When performing alkaline cleaning using an external heat shource, note or perform the following.

a) Fill the boiler system and economizer system with water. Use soft water with not greater than 1 ppm hardness as $CaCO_3$.

b) While filling, the systems shall be vented to a safe location to ensure complete filling and to prevent formation of air pockets; bleed dead legs and high points. The boiler and economizer systems should be completely filled.

c) Once the system is filled, initiate circulation through both systems and initially heat each (if separate circulation systems) solution to 60 °C (140 °F) or per cleaning vendor guidelines. Circulation through the pre-boiler system should be at the maximum permissible flow rates. Ensure that the system pressure is high enough to prevent flashing anywhere within the system and to prevent cavitation of the circulation pumps.

d) Circulation through the economizer system should be at the maximum permissible flow rate. Ensure that the system pressure is high enough to prevent flashing anywhere within the system and to prevent cavitation of the circulation pumps.

e) Circulation through the boiler system should be adequate to wet all surfaces to be cleaned (cyclones, risers, etc.). Circulation parameters should follow the vendor's guidelines to prevent preferential flow through the boiler downcomers. The purpose of the circulation is to provide a homogeneous cleaning solution at a uniform temperature. A high circulation rate will not significantly improve the alkaline cleaning process in the boiler system.

f) After the chemicals have been added and the concentration stabilized, increase the temperature to 93 °C (200 °F), measured at the outlet of the water heater.

g) Maintain the temperature between 88 °C (190 °F) and 93 °C (200 °F) at the boiler inlet during the cleaning cycle.

h) Blow down the boiler after it has been maintained at the temperature range above for 6 h. Blowing down should be done every 6 h. The intermittent blowdown valves and drain valves throughout the two systems should be opened and closed in turn. The drum water level should be lowered several inches for each blow sequence. After the blowdown procedure is complete, the water level in the boiler should be restored.

i) Low flow areas and dead ends in the economizer system should be blown down periodically during circulation to remove suspended solids.

j) Additional alkaline cleaning chemicals should be added if the concentration of any chemical component drops below 50 % of the initial concentration.

k) Unless the boiler will be subsequently acid cleaned, it should be boiled-out for at least 48 h. This extended period will promote removal of mill scale via blowdown.

l) When sample analysis indicates the cleaning can be terminated, cease firing the boiler and let the systems cool. When the boiler pressure decays to 172 kPa [ga) (25 psi (ga)], safely open the boiler drum vents.

F.4.9 Procedure—Alkaline Cleaning Using Direct Firing of the Boiler

The following steps are to be followed when alkaline cleaning the boiler using the direct firing method.

a) Fill the boiler by blend-filling the chemical concentrate. Start the chemical contractor's circulation pumps. Bleed dead legs and high points to eliminate air pockets. Adjust the boiler water level 25 mm (1 in.) above the LWA point.

b) Initiate firing of the boiler in accordance with normal, safe, start-up procedures. During this process the flue gas temperature to the boiler should not exceed 370 °C (700 °F).

c) As the water in the boiler starts to swell, the level in the drum will rise. The boiler and economizer systems should be blown down to maintain normal operating levels.

d) The pressure in the boiler drum should be higher than 172 kPa (ga) [25 psi (ga)] and no more than 75 % of the boiler design pressure.

e) The boiler should be blown down after the boiler has been maintained at the desired pressure for 6 h. Blowing down should be done every 6 h thereafter. The intermittent blowdown valves and drain valves throughout the two systems should be opened and closed in turn. Each blowdown sequence should lower the drum level several inches. After each blowdown sequence is complete, the water level in the boiler should be restored.

f) Low flow areas and dead ends in the economizer and/or evaporator systems should be blown down periodically during circulation to remove suspended solids.

g) Additional alkaline cleaning chemicals should be added if the concentration drops below 50 % of the initial concentration.

h) Unless the boiler will be subsequently acid cleaned, it should be boiled-out for at least 48 h. This extended period will maximize removal of mill scale via blowdown.

i) After the cleaning period is complete, cease firing and let the systems cool. See the section below on sampling. When the boiler pressure decays to 172 kPa (ga) [25 psi (ga)] safely open the boiler drum vents.

F.4.10 Sampling

Sampling points should be selected to provide consistent samples for analysis. Avoid points subject to extremely high or low velocities.

The alkaline solution should be analyzed every hour after the solution has reached 88 °C (190 °F), or the desired pressure, and the following criteria are met.

a) Total system is at a uniform temperature.

b) The chemicals are uniformly distributed throughout the boiler and economizer systems.

The water samples shall be analyzed for the following as a minimum:

a) PO_4 residuals,

b) pH,

c) specific conductivity,

d) oil and grease.

Other potential valuable water samples include:

a) silica pick-up (especially when a steam turbine is downstream),

b) alkalinity,

c) antifreeze.

Cleaning can be terminated when the PO_4 and suspended solids level off and traces of oil and grease are absent. At this time the alkaline solution can be drained and the systems rinsed.

Superheaters that have not been isolated should be flushed with hot condensate or demineralized water after an alkaline boilout to ensure none of the cleaning solution remains in the superheater. The flush water should be tested to confirm the quality of the water.

F.4.11 Drain and Flush Procedure

When the drum metal temperature falls below 93 °C (200 °F), open the drains fully to rapidly drain the boiler to flush any loose material from the lower drum or lower distribution manifold. Completely drain the boiler for inspection.

It is good operating practice to flush boilers until clear, effluent water is visible to ensure thorough cleaning. Systems with non-drainable pockets may require several rinses.

F.4.12 Inspection

If the alkaline wash procedure was not successful in removing oils and siliceous materials, subsequent acid cleaning, if used, may be ineffective. Therefore, if acid cleaning will follow, **it is strongly recommended to inspect the internal boiler surfaces** and repeat the alkaline cleaning procedure if necessary.

a) All sludge and loose materials in the drums should be removed.

b) Inspect for any remaining oil or grease residue.

c) Inspect the drum internals for proper condition and assembly.

F.4.13 Rinse Procedure

Refill the boiler through the economizer system with BFW or hot condensate. Demineralized water may be used if BFW or hot condensate is unavailable. If the boiler and economizer will not be acid cleaned, then adjust the demineralized water to a pH of 8 to 10 with a neutralizing amine. Add a volatile oxygen scavenger to the demineralized water.

Circulate the water through the economizer system and purge all dead legs. Displace the water through boiler blowdown valves and replace it with BFW, hot condensate, or treated demineralized water. The specific conductivity should be monitored. This process should be continued until the difference in specific conductivity between the drum water and the makeup water is less than 50 micro S/cm if acid cleaning is to follow, or less than 10 micro S/cm if no acid cleaning is to follow.

If the unit will not be inspected or started up immediately, dose the water with an oxygen scavenger (the equivalent of 200 ppm hydrazine). Refer to the Wet Storage Procedure (F.6) if start-up or inspection will be between 2 days and 1 month from the rinse. Refer to the Dry Storage Procedure (F.5) if the start-up or inspection will be delayed beyond 1 month from the rinse.

If acid cleaning is to be done, refer to the acid cleaning section of these guidelines (F.4.14).

F.4.14 Acid Cleaning

F.4.14.1 General [10]

The purpose of acid cleaning is to remove mill scale and flash rust from the internal surfaces of the economizer and boiler systems. If the boiler has been exposed to moist air for an extended time during construction and shipping, then its surfaces may have rust and may need acid cleaning. Often, initial acid cleaning of boilers is not required. The exceptions would be cases in which an entire coil has been heat treated, and that coil is subject to a high heat flux, which could form undesirable deposits on or in the tubes. When acid cleaning is needed, it is recommended that an organic acid (see 14.1.2.3.3) solution, such as inhibited ammoniated citric acid, be used for pre-operational cleaning.

F.4.14.2 Cleaning Solution

The cleaning company and purchaser are responsible to verify the compatibility of the acid with the materials in the system.

Mono-ammonium citrate and weak citric acid are some of the chemicals typically used for acid cleaning a new boiler. An inhibitor will be required to provide metal protection. Most chemical cleaning companies have proprietary citric acid solutions with inhibitors for pre-operational boiler cleaning. Ammoniated acids should not be used in systems with copper components.

Depending on the configuration of the boiler and the chemicals used, the chemical cleaning company may recommend the use of a fill and drain or forced circulation chemical cleaning system. Either boiler and economizer systems may be cleaned simultaneously or independently depending upon which chemical cleaning method is employed.

F.4.14.3 Procedure

The acid cleaning procedure is as follows.

a) If the boiler is not full of water from the alkaline cleaning, rinse and fill the boiler with BFW, condensate, or demineralized water.

b) While filling, the systems shall be safely vented to ensure complete filling and to prevent formation of air pockets. The boiler and economizer systems should be completely filled.

c) Once the system is filled, initiate circulation through the economizer and boiler systems. Heat the water to 60 °C (140 °F) using external heating equipment provided by the chemical treatment contractor.

d) Use a temporary pump, provided by the chemical treatment contractor, to circulate the water through the economizer system. It is not recommended to use condensate or feedwater pumps to circulate acid cleaning solutions. These pumps should be isolated.

e) Mix the acid cleaning solution in a separate tank and add the inhibitor. Test the cleaning solution for proper acid strength and inhibitor effectiveness. This is typically done using a “steel wool test.” Refer to the chemical cleaning company for specific guidance on this procedure.

f) When the water temperature reaches 60 °C (140 °F), introduce the chemicals by injection. The chemicals should be added at such a rate so that the maximum concentration is not exceeded in any part of the system.

g) Circulation of the acid solution should be moderate. The objective of circulation is to maintain a homogenous temperature and concentration within the solution.

h) After the chemicals have been added and the concentration stabilizes, increase the temperature to that recommended by the chemical cleaning company, typically 93 °C (200 °F). Drain dead legs to ensure proper cleaning in all areas.

i) Maintain the moderate circulation at the temperature range recommended by the chemical cleaning company—for approximately 6 h. A typical temperature range is between 82 °C (180 °F) and 104 °C (220 °F).

F.4.14.4 Sampling

Sampling points should be selected to provide consistent samples for analysis. Avoid points subject to extremely high or low velocities.

The acid cleaning solution should be analyzed every hour after the solution has reached 82 °C (180 °F).

The water samples should be analyzed for iron and solvent concentrations.

Cleaning can be terminated when these concentrations become stable.

F.4.14.5 Flush Procedure

For neutralization and passivation of a new boiler after the ammoniated citric acid clean, often NH_3 is added to the ammoniated citric acid solution to a pH of 9.5 and then is rinsed out, rather than a separate neutralization and passivation step. Upon completion of cleaning, removal of the solvent solution should be done by the displacement method. Spent solvent should be displaced with BFW. Care should be taken to purge dead legs and low flow areas.

Refer to 14.1.2.6 for further guidelines.

F.4.14.6 Passivation and Neutralization After Acid Cleaning

Flush the boiler with demineralized water until the electrical conductivity of the water is within 1 mS/m (1 mmho/m) to 5 mS/m (5 mmho/m) maximum differential of the makeup rinse water. If the conductivity cannot be reduced, draining may be required. Draining should be done with a nitrogen purge so that the water is displaced with nitrogen.

Once the conductivity has been lowered to an acceptable level [(less than 5 mS/m (50 μmho/cm)], increase the pH to a minimum of 9 with sodium carbonate. Fire the pilots and/or burners to achieve a drum pressure of 690 kPa (ga) to 1380 kPa (ga) [100 psi (ga) to 200 psi (ga)]. Maintain condition for 12 h to 24 h.

This formulation should be circulated for 4 h to 6 h at temperatures between 27 °C (80 °F) and 82 °C (180 °F).

F.4.14.7 Rinse Procedure

Rapidly drain the boiler to flush any material from the lower headers.

Refill the boiler through the economizer system with BFW, hot condensate, or demineralized water. Adjust the pH to within the range of 8 to 10.

Circulate the water through the economizer system and purge all dead legs. If the unit is to be started up within two or three days, add a non-hydrazine oxygen scavenger (equivalent to 200 ppm hydrazine) to the boiler water by circulating it through the pre-boiler system and maintain the pH between 8 and 10 with NH_3. Nitrogen purge all vapor spaces, including the superheater. If it is to be stored for a long period of time, refer to the Dry Storage Procedure (F.5).

F.5 Dry Storage Guidelines

F.5.1 Introduction

This procedure provides a method to reduce corrosion (e.g. oxygen attack) on the inside of the heating surfaces and drums when storing the boiler for extended periods. This method may be of value during construction, if the time from delivery to start-up is expected to be more than 6 months.

- The owner shall evaluate if the cost involved is outweighed by the possibility of damage to the equipment and its downtime.

F.5.2 General

The dry storage method shall be used when the boiler:

a) is going to be idle for more than 1 month,

b) had been operating or chemically cleaned, or

c) may be subject to freezing conditions.

Either of the following options may be used for low-pressure 2.07 MPa (ga) [300 psi (ga)] or less boilers. Above 2.07 MPa (ga) [300 psi (ga)], both procedures should be combined. Review the operating pressure and the configuration of the system to determine which method or if both methods are best.

a) The nitrogen purge procedure is generally used before start-up of the boiler. The nitrogen purge procedure may not dry out the inside of the equipment. It is designed to eliminate oxygen and prevent the resulting corrosion.

b) If the boiler components have been full of water, drain and then use a desiccant procedure. The desiccant procedure will dry out the inside of the boiler tubes, drums and the superheater and economizer tubes that are not isolated from the boiler. It will require maintenance, since the equipment shall be opened and inspected periodically. The desiccant can become saturated with water and will need changing.

F.5.3 Procedure Utilizing Nitrogen

A nitrogen purge shall be used to displace air that can lead to oxygen attack. For a new boiler that is being stored:

a) place seals on the inlet and outlet(s) of each header, or the inlet and outlet of the piping. The seals may be temporary rubber plugs or welded caps, but shall be able to withstand 34.5 kPa (ga) to 69 kPa (ga) [5 psi (ga) to 10 psi (ga)] pressure;

b) slowly introduce nitrogen into the lowest header of each tube bundle—boiler, economizer, and superheater if applicable. The slow nitrogen flow (less than 2.360 dm^3/s (5 SCFM) at standard conditions of 15 °C (59 °F) and absolute pressure of 101.325 kPa (14.7 psig) will ensure complete displacement of the air. Inject nitrogen into the boiler until the exhaust from the upper high point vents is void of oxygen.

Caution—Whenever purging with nitrogen, ensure personnel are out of any area where an oxygen deficient atmosphere can be present.

c) Connect a nitrogen supply with a pressure gauge and regulator to a low point drain. After displacing all oxygen, maintain a nitrogen positive pressure of 20.7 kPa (ga) to 34.5 kPa (ga) [3 psi (ga) to 5 psi (ga)] during the entire storage period.

For a boiler that has been in operation or has been pressure tested and is ready for normal operation:

a) Slowly introduce nitrogen into all low points while allowing the unit to drain. A slow nitrogen flow (less than 2.360 dm^3/s (5 SCFM) at standard conditions of 15 °C (59 °F) and absolute pressure of 101.325 kPa (14.7 psi) will ensure complete displacement of the air. When the unit is drained, open the high point vent and continue to inject nitrogen into the modules until the exhaust from the upper header is void of oxygen.

Caution—Whenever purging with nitrogen, ensure personnel are out of any area where an oxygen deficient atmosphere can be present.

b) Connect a nitrogen supply with a pressure gauge and regulator to a low point drain. After displacing all oxygen, maintain a nitrogen positive pressure of 20.7 kPa (ga) to 34.5 kPa (ga) [3 psi (ga) to 5 psi (ga)] during the entire storage period.

c) Seal all openings to prevent excessive use of nitrogen when the oxygen displacement is completed.

F.5.4 Procedure Utilizing Desiccant

For desiccant use, perform or note the following.

a) Cool and completely drain the boiler components. Note that superheaters and economizers may have their own drains. To the extent possible, eliminate all pockets of water left in the superheater, boiler, economizer, water columns, etc.

b) Place water-tight, corrosion-resistant (e.g. wood, plastic) trays inside each drum, and evenly spread moisture absorbent material (desiccant) onto them. This material will absorb any moisture that becomes trapped after closing the unit.

c) Place the trays on supports to allow air to circulate both above and below them. The trays should not be more than $^3/_4$ full of the dry desiccant to prevent overflow of the corrosive liquid, after absorption of the moisture.

d) The following are acceptable desiccants.

   1) Quick lime—0.96 kg/m^3 (0.06 lb/ft^3).

   2) Silica gel—1.28 kg/m^3 (0.08 lb/ft^3).

   3) Activated alumina—1.28 kg/m^3 (0.08 lb/ft^3).

e) Other desiccants may be used with the approval of the user, after user has been informed where the desiccant has been used successfully.

f) Close all openings to prevent water, steam, or air leakage into the unit.

g) Open the drum manways to inspect the desiccant periodically (every 60 days minimum). Check that no corrosive action is taking place and replace the spent desiccant as needed. Reseal all openings immediately after inspecting.

F.6 Wet Storage Guidelines

F.6.1 Introduction

The wet storage method may be used to protect the boiler when the boiler is going to be idle between 2 days and 1 month. It is often used if a quick start-up is needed. In any case, there shall be no chance of the ambient temperature dropping below freezing. The remainder of this chapter discusses wet storage for this time period.

There is still a possibility of freezing if the boiler is inside an enclosure. This can occur if the outside ambient temperature goes below freezing and the enclosure is insufficiently heated and/or insulated.

Proper wet storage of the unit will prevent corrosion of the internal surfaces by eliminating oxygen and maintaining acceptable pH.

F.6.2 Procedure

Prior to shutting down the boiler, blowdown the lower drum until there are no visible suspended solids in the blowdown water. If after 2 min, the boiler water contains dirt or any solids, shut down and drain the unit. If the water is visibly free of solids there is no need to drain the boiler. Refer to the blowdown guidelines in this section.

Refill the boiler after draining:

a) Close the NRV and all boiler drains.

b) Open the boiler drum vent.

c) Fill the economizer and boiler with BFW including the steam drum to normal operating level. If BFW is unavailable, use condensate or treated demineralized water. The superheater is water free. Since there will be little or no head imposed on the feedwater pumps by the boiler system, the feedwater control valve bypass (if applicable) should be used while filling.

   While filling the boiler, increase the dosage of amines to achieve a pH of 10.5 and oxygen scavenger to achieve 100 ppm sulfite or an equivalent of 200 ppm hydrazine residual.

Caution—All chemicals shall be added in a diluted liquid form. Concentrated chemicals or solid chemicals should never be introduced into the system.

If the system has been drained, the storage chemicals can be added as the boiler is refilled. Solutions of these chemicals shall be added slowly so that they are dilute, as water is being added.

Water treatment companies typically have storage chemicals available in a premixed form. Consult as appropriate for specific recommendations.

d) Manually close the feedwater control valve and throttle the bypass valve to protect the pumps when the boiler, drums, and all coils are vapor-free.

e) After the chemicals have been added, the water shall be circulated by one of the following methods.

   1) Lower the drum water level to its centerline and open the steam drum vent valves. Introduce regulated {172 kPa (ga) [25 psi (ga)]} saturated steam through the intermittent blowdown valves. Circulate the boiler by this method for approximately 2 h.

   2) Circulate the drum water from the feedwater connection back to the intermittent blowdown with an external pump. Circulate the boiler water for approximately 2 h with the boiler and economizer full and all vents closed.

f) Install a nitrogen bottle with a pressure regulator and indicator to the steam drum vent, and pressurize the boiler to 34.5 kPa (ga) [5 psi (ga)].

g) Test the boiler water once each week by taking a sample from the continuous blowdown line. Add chemicals through the chemical feed connection, when necessary. If chemicals are added, circulation will be necessary.

F.7 Pre-start-up Inspection

F.7.1 Introduction

This section provides guidelines for the initial inspection of the boiler after hydrostatic testing or for an inspection after the boiler has been shut down for repairs, modification, or after an extended outage.

Before start-up, walk around the entire boiler system and examine all the mechanical systems.

Specifically check the following.

a) Piping and pipe supports.

   1) The chemical feed line shall be placed to one side of the drum and the holes shall align to discharge the chemicals horizontally. Verify that the chemical feed line has proper drain and vent connections.

b) Ductwork.

c) Expansion joints.

d) Level gauges are functional by blowing down the glass and watching the return of level in the gauge.

e) Access doors and manway doors are tightly closed.

f) If any work has been done on the boiler since the last operating period, ensure that all systems are back together.

g) Hydrotest-stops are removed from spring pipe supports.

h) Ensure all orifices and flow devices are properly installed.

i) Ensure all blinds used for hydrotesting or chemical cleaning have been removed.

j) Ensure temporary gauge glasses installed for cleaning have been replaced by the permanent gauge glasses for operation.

F.8 Boiler Filling Guidelines

F.8.1 Introduction

This section provides guidelines for filling the boiler system with water.

F.8.2 Pump Considerations

The initial fill of the boiler shall be done to prevent damage to the feedwater pumps.

a) Review the pump curves to determine the impact of running the pumps without backpressure. Many multistage feedwater pumps require a discharge head to help offset the thrust the water puts on the thrust bearings. Pumping without a minimum back pressure can cause excessive wear on pumps.

b) The power requirement to pump more water at a low pressure is higher than pumping a low flow at high pressure; you shall verify that the motor, starter, and heaters are sized to handle the boiler filling requirements.

c) Check the shutoff head of the feedwater pump and compare with any pressure safety valve settings. Some economizers can be isolated or bypassed. If this is the intention, a PSV shall be installed to protect the coil. The valve setting should be above the shutoff head of the feedwater pumps.

d) If the feedwater pumps are not sized to handle the filling either install a bypass from the makeup water pumps to fill the units, install a temporary pump, or create backpressure using the system valves.

See Section 9 for BFW quality guidelines.

F.8.3 Chemical Feed Equipment

To ensure proper boiling water quality, perform or note the following.

a) Verify that all chemical feed equipment is working, there is an adequate supply of chemicals on hand, and calibrate all analyzing equipment.

b) Check the feedwater chemistry for proper quality.

c) If the boiler has been stored for one or more weeks, check the drum water chemistry. Drain and refill the unit if necessary.

   1) Initially it may be necessary to use high concentrations of oxygen scavengers, since there may not be deaerated water available.

   If there are any doubts about water chemistry, consult with a water treatment specialist.

F.8.4 Water Levels

The proper level of water in the boiler drum is critical to the operation and safety of the boiler. Water levels below those recommended on the drawings (reference P&ID), can cause major damage to the boiler drums and tubes. High levels may lead to carryover of water and can damage downstream equipment. Check the OEM instructions for the initial fill level. Typically the level will be low to allow for the level swell that occurs with the onset of boiling. If there are no specific recommendations, fill the drum.

F.8.5 Precautions

Water level precautions are as follows.

a) Vents will discharge water during the boiler filling process. Personnel shall be positioned such they are not endangered by the water discharged from the vents or other open valves.

b) Use only good quality (deaerated if available) BFW when filling the boiler. If deaerated boiler feedwater is unavailable, refer to F.8.3 a) of this document.

c) Do not apply any pegging (equalization) steam to the deaerator until water flow has been established or damage to the deaerator could occur. It is recommended to use liberal amounts of oxygen scavenger for the initial charge of water in the deaerator storage tank.

F.8.6 Procedure

The boiler water level setting procedure is as follows.

a) Open all vents and close all drains.

   NOTE Refer to the Pre-operational Cleaning Guidelines (F.4) if flushing is desired before filling. If the boiler is being filled for wet storage, refer to the Wet Storage Guidelines (F.6).

b) Begin slowly filling the boiler by using the BFW control valve bypass.

c) Station an operator at the top of the unit to close economizer vents as the unit is filled. Close the vent valves after water is freely flowing from the vents.

d) Note when the water level appears in the gauge glass and fill to the required start-up level. The start-up and drum vents should remain open if the unit is to be started up.

Refer to F.5, F.6, and F.13 of this document for proper shutdown and storage procedures if start-up is delayed.

F.9 Field Hydrostatic Testing Guidelines

F.9.1 Introduction

- The field hydrotest is conducted as the final phase of installation or repair to ensure that the system is free from leaks and that the system has the mechanical integrity to retain pressure. Pneumatic testing or mass-spectrometer and halide leak testing may be used with the approval of the owner, his/her agent, and the AI. Pneumatic testing (see ASME *BPVC* Section VIII, Division 1, UG-100) may not be implemented should the ambient air temperature be less than 16 °C (60 °F). All testing shall conform to ANSI 31.1 and applicable sections of the ASME *BPVC*.

F.9.2 Equipment and Supplies Required

The following equipment and supplies are required for the hydrotest procedure.

a) Potable water at ambient temperature, not less than 21 °C (70 °F) nor greater than 49 °C (120 °F). Chloride levels shall not exceed 50 ppm when austenitic stainless steel is present.

b) One (1) recently calibrated pressure gauge with a range of one and one half to two times the test pressure.

c) Blinds for the safety valve nozzles. Longer studs than those supplied with the safety valves may be required to accommodate installation of these plates.

d) Pump capable of attaining the required hydrostatic test pressure.

e) Pump safety valve set at 5 % over the hydrostatic test pressure.

f) Temporary supports necessary to provide added support to the system due to the extra mass of water required during the hydrotest.

If the hydrostatic test pressure shall be exceeded by more than 6 % for Section VIII vessels, contact the OEM for additional hydrotest requirements before testing.

F.9.3 Procedure—Preparation

The hydrostatic test procedure is as follows.

a) Engage travel-stops on the piping spring supports (if applicable).

b) Confirm the area is secured so neither equipment can be damaged nor personnel can be injured.

c) Ensure all access and exit areas for personnel are clear, clean, and removed of obstructions

d) Install the hydrotest pump and the pump safety valve upstream of the feedwater control station.

e) Blank off (blind) any safety valves and any instruments that cannot withstand the hydrotest pressure.

f) Gags may be used to keep the safety valves closed, but the valves may be required to be recertified after breaking the seal to install the gag.

g) Boilout gauge glasses cannot be used for the hydrotest. They shall be removed and replaced with piping suitable for the hydrotest pressures.

h) Install the calibrated pressure gauge so it is visible to the person controlling the hydrotest pressure.

i) Where hydrotest water will be filling piping, tubing or other equipment normally in steam service, temporary pipe supports sufficient to support the additional weight of the water during hydrostatic testing shall be installed.

j) All constant or variable spring supports for piping not normally filled with water shall be blocked or pinned before filling the system with water.

k) Open all header, drum, line, etc. high-point vents.

l) Begin filling the system with water.

Caution—Make sure the pressurization process is under control. The hydrostatic test pressure shall never be exceeded by more than 6 % for Section I vessels.

m) Begin pressurizing the system at a maximum rate of 69 kPa (10 psi) per minute. When the pressure reaches 172 kPa (ga) [25 psi (ga)], open all vents briefly to remove air from the system. Close the vents after the air has cleared and water is flowing freely.

n) Increase the pressure to 345 kPa (ga) [50 psi (ga)]. If any gross leaks are found, reduce the pressure to zero and take the proper steps to repair the leak(s).

o) If no leaks are found increase the pressure to 20 % of the hydrostatic test pressure and check for leaks. Again, if any gross leaks are found, take repair action before application of full pressure.

p) If no gross leaks are found, bring the system up to test pressure and hold for not less than 10 min and no more than 1 h. Close visual inspection is not required during this stage.

q) Reduce the pressure to the design pressure and closely inspect and mark any leaks.

r) Take the proper steps to repair all leak(s) and re-hydrotest.

s) Any valve bonnets or packing nuts that have been weeping or leaking at maximum test pressure shall be water tight at the design pressure.

t) Drain the system and prepare for internal cleaning.

u) After internal cleaning, remove any temporary pipe supports and blocks from spring supports. Set spring supports per the drawings.

- Piping that cannot be hydrotested safely or where hydrotesting is not practical may be tested by an initial service test. This shall be agreed to by the owner and the AI. Trim that shall be protected from hydrostatic test pressure:

a) pressure gauges,

b) pressure transmitters,

c) liquid level gauges,

d) liquid level transmitters,

e) safety valves.

Initial service test—An initial service test is a leak test where the piping is gradually brought up to normal operating pressure and held for a minimum of 10 min. Examination shall be made at all joints and connections. The piping system exclusive of pump or valve packing shall show no visible evidence of leaking or weeping. Source: ASME B31.1.

F.10 Intermittent Blowdown (IBD)

IBD acts to remove accumulated sediment from the boiler. The IBD is located at a low point of the mud drum or intermediate headers where the velocity of water flow is low. IBD is performed at prescribed intervals. Daily or once per shift are typical IBD intervals. The interval can be adjusted per the water quality and chemical treatment. Consult the boiler manufacturer and water treatment service company for specific guidance.

The IBD should be brief (on the order of several seconds). The recommended practice is to quickly open the valves wide open for 5 s and then quickly close the valves, unless the line is relatively cold. A cold line may require the valve to be opened slowly. The intermittent blowdown is normally a manual operation, but can be automated.

Valve opening sequence:

a) open the IBD valve nearest the boiler wide open,

b) quickly open the subsequent valve wide open,

c) allow to flow for 5 s,

d) rapidly close the valve furthest from the boiler,

e) close the valve nearest the boiler.

F.11 Personnel Protection

Boiler systems may have hot surfaces that pose a burn-risk hazard. Surfaces may include uninsulated areas such as ducts, stack, viewports, valves, and pipes.

Burn-risk surfaces can be covered with insulation if acceptable for the process and mechanical design conditions. Expanded metal can be used otherwise to protect personnel. The addition of insulation to hot surfaces should be approached with care as certain surfaces are not intended to be insulated. For example, steam condensate pots will not function properly if insulated. Flanges operating in a creep-rupture zone can creep and leak if insulated. The addition of insulation to a breeching may result in a sharp temperature gradient and high thermal stress.

Covering a hot casing with insulation may not always be an option. It can elevate the casing temperature where it can weaken or deteriorate. It is recommended that the OEM be contacted before adding external insulation to boiler components.

As received from the boiler OEM, vents, safety valves, and drains may not, as yet, be piped to safe locations. All discharge lines with the potential to discharge steam or hot water shall be piped to a safe location.

Cracks in the boiler casing can discharge flue gas at high temperatures when the boiler flue gas side operates above atmospheric pressure. Casing cracks in locations of human traffic shall be repaired promptly or roped off until such repairs can be made.

External steam leaks pose burn hazards similar to the flue gas leaks discussed above with the additional risk of catastrophic failure. The access zone around steam leaks shall be restricted to take into account the possibility of such failures.

Boiler manway gaskets can fail catastrophically. Manway bolts should be torqued according to OEM procedures.

F.12 Start-up (Sample Procedure)

F.12.1 General

Boilers should generally follow the intent of NFPA 85.

The following start-up procedure does not address a refractory dry-out that may be required. A refractory dry-out may be conducted prior to or simultaneously with the initial burner start-up, but only in accordance with the boiler and/or refractory vendor's recommendations.

F.12.2 Feedwater Start-up

To start the feedwater system, perform the following.

a) Superheater and economizer vents should be open during start-up. If not open, open them.

b) Close the mud drum and any other drain valves prior to establishing level in the steam drum.

c) Verify the feedwater availability including all utilities for the feedwater pumps (e.g. lube oil, cooling water, steam, valves, and instruments) are prepared for operation.

d) Verify that water treatment facilities (e.g. O_2 scavenger, neutralizing amine, PO_4, chelant, polymer, etc.) are lined up and available to the equipment.

e) Start one feedwater pump in according to the manufacturer's instructions and prepare remaining backup pumps for automatic re-start.

f) Check for leaks, hot bearings, changing steam drum or deaerator levels, and abnormal noise and vibration.

F.12.3 Establish Steam Drum Level

Set the steam drum water level by performing the following.

a) Continually monitor the deaerator level.

b) Establish steam drum water level for operation. Initial fill point shall be 25 mm (1 in.) above the LWA point to account for swell as the boiler heats up.

c) If equipped, open BFW start-up bypass for better flow control. When doing so, the BFW control valve should be on MANUAL.

d) Continually monitor the level in the steam drum.

e) During start-up, the boiler begins producing steam and the drum level initially swells. The water "swells" as it is heated because its volume increases. High drum level is typically manually controlled through intermittent blowdowns. As the steaming rate increases, the steam flow through the start-up system begins to counteract the effect of boiler water swell and additional feedwater may be required. During this time period when boiler water blowdown is higher than normal, phosphates are pumped to the steam drum at increased rates.

f) The steam drum continuous blowdown is not large enough to control the swell during start-up. The head of water in the boiler section tubes moves the water through the opened bottom or mud drum intermittent blowdown valves to the intermittent blowdown drum. This lowers the level in the drum quickly and is used during start-up when pressure in the boiler is low. Operation of the valve during normal operation will cause a rapid decrease of drum level and could result in a unit trip on low drum level. Intermittent blowdown is used during normal operation to remove suspended solids from the mud drum. It shall be done carefully in order to not drop the drum level.

g) Open the normal BFW control valve to the boiler.

h) If an economizer is present, establish a continuous blowdown rate to ensure the economizer will not be subject to thermal shock or fatigue when steam begins to be generated. Continuous blowdown rate should be sufficient to provide a continuous flow through the economizer.

F.12.4 Line Up Air and Fuel Systems, Flue Gas Analyzers

Prepare the air and fuel systems and flue gas analyzers.

a) Line up FD/ID fans.

1) Commission FD and ID draft fans in accordance with procedures recommended by the fan vendors.

2) Verify all utilities for the fans (e.g. lube oil, cooling water, steam, etc.) and auxiliary systems (dampers, valves, instruments, etc.) are prepared for operation.

b) Line up fuel gas supplies.

1) Open valves on the supply line to the burner fuel gas supply header. The fuel gas supply header is checked for leaks.

2) If appropriate, verify igniter and main burner fuel gas composition and quality.

c) To avoid the potential ignition of combustible gases in vicinity of the flue gas analyzers, commission flue gas analyzers in accordance with procedures at the correct step in the start-up sequence.

1) Flue gas analyzers with flame arrestors may be commissioned prior to the purge cycle.

2) Flue gas analyzers without flame arrestors should not be commissioned until after purge complete to remove heated oxygen or combustibles sensors as a potential ignition source to combustible gases being purged during the purge cycle.

NOTE Upon restoring power after an extended outage, a cold combustibles or methane sensor at ambient conditions may have an extended warm-up period (e.g. 4 h to 6 h) for the sensors to stabilize to their published accuracy. Upon restoring power after a brief outage, an oxygen/combustibles sensor may require stabilization time (e.g. 15 min to 30 min) to achieve published accuracy. Refer to vendor manual for sensor warm-up requirements.

F.12.5 Pre-purge Cycle

Perform the pre-purge cycle.

a) All air registers shall be open sufficiently so that the airflow is not restricted during the purge. The field operator will open them from the field console (or manually) and they shall be verified by limit switches on the BPCS or other control panel (if so equipped) or verified manually.

b) The boiler shall be purged of any flammable gases that remain in the boiler or that leak through the burner, fuel gas, or block valves. The purge shall be conducted with use of the ID fan, FD fan, both fans, or, in the case of a natural draft boiler, by other means.

c) Check or verify the purge permissives. This includes checking or positioning steam, gas, fan, superheater, and air valves.

d) When the purge permissives are satisfied, press the start purge button on the field console. If purge does not start, correct any problems with purge permissives prior to restarting purge.

Caution—A failure of combustion airflow during light-off can create an explosive condition within the furnace and boiler internal passages. A low airflow interlock will shut off the fuel gas to avoid such a condition. It is necessary to prove that the low air flow instrument is working properly before the system will allow a purge.

e) Verify purge in progress (see start-up sequence on display panel). The air purge requirement shall be greater than five furnace volume changes for multiple burner boiler or eight furnace volume changes for single burner. The air purge requirement shall be a minimum of 5 min for multiple burner boilers.

f) Complete purge before lighting igniters. Ensure that any FGR ducting is also adequately purged in addition to the boiler firebox and enclosures. Consult NFPA 85 for guidance.

g) When purge is complete, the BMS holds for the console operator to confirm "Ready to Start."

h) Upon confirmation of "Ready to Start" the BMS transitions the boiler to light-off conditions: positioning fuel valves, air registers, etc., as applicable.

F.12.6 Igniter Light-off

Perform the igniter light-off per the following steps.

a) Upon purge complete, confirm that light-off conditions are established (e.g. positioning fuel valves, air registers, etc.) prior to starting the ignition sequence.

   Caution—Excessive delay with light-off after a successful purge can allow an accumulation of combustible gases. Consider a light-off time limit timer.

b) As soon as purge is complete, light initial igniter. The igniter flame shall be established and proven within the TFI period.

c) Light-off igniter burners. Sequence includes energizing ignition transformer for providing spark for the igniter. Prove igniter flame.

   NOTE Igniters are used to provide the ignition source for main burners under prescribed light-off fuel and air conditions to specific burner location.

d) Continually monitor igniter burner performance.

   NOTE For intermittent igniters, gas to each igniter burner is blocked-in after each main burner has been ignited. For continuous igniters, the igniter gas flow is uninterrupted.

F.12.7 Light-off Main Burners

Light the main burners by performing the following operations.

a) Confirm the igniter burner is lit with its associated flame detector before attempting to ignite the main burner.

b) Once each igniter flame is proven and stable, set each air register to the position recommended by the burner vendor prior to lighting the main burner.

   NOTE The combustion air (or required draft, if applicable) is adjusted according to OEM operating procedures by using the stack damper/fan damper and air registers before lighting burners.

c) Begin preparation to light-off main burners in accordance with the BMS. When the fuel gas header pressure reaches the appropriate level as described by the OEM's operating procedure, the first burner may be lit. Depress the associated main burner start pushbutton or light the burner. This step may be automatically initiated by the BMS. The main flame shall be established and proven within the TFI period.

d) Place the control system in manual mode in order to control heat input per OEM's ramp-up rate for any refractory curing needed.

e) Should the initial burner fail to ignite, block it closed and open its air register fully to allow the burner area to purge. Follow NFPA 85 for purge period guidelines.

f) Should a subsequent burner fail to ignite, block it in, and open its air register fully to allow the burner area to purge. Follow NFPA 85 for purge period guidelines. During this interim period, another burner may be lit; it should be located as distant from the failed burner as possible.

Caution—When adjusting burner pressure via a control valve (i.e. in lieu of a pressure regulator) an additional burner may not be lit until the burner pressure is raised sufficiently to ensure that introducing fuel to the next burner will not place all burners in a low fuel pressure, unstable condition.

g) Monitor main burner for flame shape, length, color, stability with no pulsing, and pattern. Main burner flame can be verified via flame scanner signal on the control panel in the field or visually via the sight port on the burner.

NOTE Should the burner trip offline upon loss of flame signal when flame is visually confirmed, the problem may be poor directional sighting of the flame scanner or incorrect tuning. The scanner may have to be adjusted or tuned.

h) Continue lighting igniter and main burners, as necessary to meet manufacturer's specified steam drum ramp-up rate. Ramp-up rate should never exceed 56 °C (100 °F) per hour. Ramping up too quickly can overstress mechanical components and void manufacturer's warranty. Prior to igniting each additional burner, ensure burner pressure will be satisfactory to prevent the burners from blowing out. Burners shall be distributed appropriately to give even heat distribution.

NOTE The outside field operator works with the control room operator to bring steam drum water temperature gradually up to desired temperature. The temperature is increased slowly to prevent thermal stress to the steam drum/steam generator tube welds.

i) Observe steam drum water level and keep between level ranges recommended by OEM guidelines.

j) Verify level indicators against gauge glasses during start-up.

k) Close the drum and economizer vents when pressure reaches OEM specifications. When pressure reaches OEM specifications, close the superheater drain to sewer. The superheater vent to atmosphere stays open until the boiler is online.

l) Main steam from the superheater is diverted through the start-up header isolation and control valves and silencer to the atmosphere during start-up until the temperature and pressure of the steam matches main steam header steam conditions. The steam is then directed to the plant's steam header, and the dump-through the silencer is isolated. Steam pressure increases to overcome the boiler's NRV until that valve opens automatically.

NOTE Blow boiler using continuous and/or manual blowdowns to control high level.

m) Increase BFW as needed to maintain level above low water trip point.

n) When temperatures and flows are stable at the desired start of cycle conditions, switch to automatic control.

o) Once burner flame is stable, block in steam coil (if applicable) to mud drum.

NOTE Check the steam quality within 3 days (or after the operation has stabilized) of starting up a boiler after turnaround, especially if the water side has been opened and inspected. This can be a grab sample vs testing with an online sodium analyzer.

F.12.8 Fundamental Operating Rules

It is important to note and follow these fundamental operating rules.

a) Do not exceed boiler heat-up rate.

b) Check for steam leaks throughout the start-up.

c) Maintain boiler drum level in the mid-range to prevent carryover and avoid uncovering tubes.

d) Remove condensate from steam equipment and piping during start-up to prevent water hammer and equipment damage.

e) Maintain deaerator water level during start-up to prevent loss of feedwater pump.

f) Superheater vents should be open during start-up and shutdown only.

F.13 Shutdown

The following procedures should be performed when it is necessary to take a boiler out of service.

a) Reduce the steaming rate slowly.

b) When the steaming rate reaches 25 % to 30 % of the rated capacity, put the burners on manual control.

c) Close the main gas shutoff valve when the load has been reduced per OEM guidelines. In multiple-burner boilers, the operator may isolate burners individually to reduce boiler load.

d) Allow the fuel in the furnace to burn out while allowing the fans to purge the furnace until all the fuel is completely burned.

e) Put the feedwater control in manual and maintain water level.

f) As soon as the stop check valve closes and where a superheater exists, open and throttle the outlet superheater header drain to allow circulation through the superheater until the furnace drops below the point at which superheater overheating could occur.

g) Close the inlet and outlet dampers to the boiler to allow the temperatures to drop slowly.

h) Close the feedwater valves when the boiler ceases to require water.

i) When the drum pressure reaches just above atmospheric, open the drum vents and superheater drains where applicable.

j) The boiler may be drained when the boiler water reaches 93 °C (200 °F).

Annex G
(informative)

Inspection Test Plans

INSPECTION AND TESTING CHECKLIST

REVISIONS					
NUMBER	0	1	2	3	4
DATE					
ORIGINATOR					
REVIEWED					
APPROVED					

Doc. No:

JOB NUMBER	PAGE	1	OF	3
CLIENT				
LOCATION				
UNIT				
ITEM NUMBER				
SERVICE				
REQUISITION NO.				

INSPECTION AND TESTING REQUIREMENTS

LEGEND
R = Report Required, Non-Witness
W = Witnessed
E = Examine
X = Required

Description of Examination	Boiler						Comments
1 INSPECTION LEVEL							
General	2						
a. Drums (Steam / Water)	2						
b. Headers (boiler, superheater, economizer)	2						
c. Superheater (tubes & assembly)	2						
d. Boiler Tubes (standard)	2						
e. Boiler Tubes (alloy)	2						
f. Interconnecting (Code) piping and valves	2						
g. Economizer (tubes & assembly)	2						
h. Desuperheater / Attemperator	2						
i. Boiler (shop) assembly	2						
j. External (non Code) piping and valves	2						
k. Stack	2						
l. Air & Gas Ductwork	2						
m Purchased (buy out) items	2						
n. Structural (Supports, Ladders, Platforms, etc.)	2						
o. Electrical	2						
p. Instrumentation	2						
2 PRE-INSPECTION MEETING							
a. Purchase Order review	X						
b. Review Supplier's QA/QC plan	X						**Review major sub-supplier QA/QC plans**
c. Manufacturing Schedule	X						
d. Welding Procedures	X						**Review sub-supplier procedures**
e. Welder Qualifications	X						
f. NDE Procedures	X						**Review sub-supplier procedures**
g. Sub orders (provide copies of sub orders)	X						
3 FABRICATION INSPECTION							
a. Material substitution requests	X						
b. NDT Procedures	X						
c. Test Procedures	X						
d. Sub Orders (provide copies)	X						
e. Weld Repair Procedures (Repair Plan must be	X						
approved prior to start of repairs)							
4 VISUAL AND DIMENSIONAL CHECK							
a. Customer connection within pipe tolerances	E						
b. Foundation foot print	E						
c. Piping fabrication & installation	E						
d. Assembly fit up prior to welding	E						
e. Review maintainability & access requirements	E						
f. Confirm instrumentation per area classification	E						
g. Confirm piping, valves, instrumentation per P&ID	E						
h. Confirm instruments per BOM	E						
i. Earth continuity check	E						
j. Verify tagging and labels per drawings	E						

INSPECTION AND TESTING CHECKLIST

JOB NUMBER	0	PAGE	2	OF	3
ITEM NUMBER	0				

Doc. No: 0

INSPECTION AND TESTING REQUIREMENTS

Description of Examination	**Boiler**						**LEGEND** **R = Report Required, Non-Witness** **W = Witnessed** **E = Examine** **X = Required** **Comments**
5 MATERIALS CERTIFICATION							
a. Drum plate and heads	R						
b. Pressure containing parts & nozzles	R						
c. Tubes	R						
d. Fittings, Flanges, Bolts	R						
e. Instrumentation	R						
f. Alloy materials verification	E						
6 NON-DESTRUCTIVE EXAMINATION							
a. Magnetic Particle/Liquid Penetrant Examination	R						
b. Radiography/Ultrasonic	R						
7 PRESSURE AND LEAK TESTING							
a. Hydrostatic	W						
b. Pneumatic							
8 SHOP TESTING							
a. FAT of control panels	R						
b. Functional test of skid assemblies	W						During Final Inspection
c. Fan Performance Test	R						Requires Engr. approval of test results
d. Run test of sub assemblies	R						Requires Engr. approval of test results
e. Wiring continuity and loop checks	R						
f. Sound level checks	R						For all equipment 85 dBA or higher
g. Motor tests	R						
h. Certified copies of test data	R						
9 Painting / Coatings	E						
10 Preparation for Shipment							
a. Preservation	W						
b. Export Packing	W						
c. Dimensional Check for Cargo Limitation	W						
d. Verify Packing List for Box Contents	W						
e. Inspection Release Certificate	X						

Remarks:

Job No: 0	Doc. No.: 0	Rev. 0	Page 2 of 3

INSPECTION AND TESTING CHECKLIST

JOB NUMBER	0	PAGE 3	OF	3
ITEM NUMBER	0			

Doc. No: 0

INSPECTION AND TESTING REQUIREMENTS

1.0 GENERAL DEFINITIONS

1.1 The Purchaser's inspection policy provides for surveillance of a supplier in which random audits and inspections are performed throughout their organization sufficient to ensure compliance with purchase order requirements.

1.2 Inspection will be based on inspection levels as defined below:

Level No. 1 - Final inspection only prior to shipment, and issue of an Inspection Release Certificate. When complexity of an item warrants, a Pre Inspection Meeting may be held.

Level No. 2 - Includes the conducting of a Pre Inspection Meeting, one or more in process surveillance inspection visits as necessary, witness of major tests, review of required documentation, and issue of an Inspection Release Certificate.

Level No. 3 - Same activities as Level No. 2 except regular inspection visits are more frequent, based on milestones as well as witness/hold points specified in the Pre Inspection Meeting.

Level No. 4 - Resident inspector continuously monitoring the work in addition to activities outlined in Level No. 2.

1.3 The extent of surveillance inspection activities is defined as follows:

Report Required, Non-Witness **(R) -** Inspection activity performed by the Supplier's inspector or qualified NDE Company technician. Test reports, procedures, and other documentation shall be submitted to Purchaser's inspector for review.

Witness **(W) -** Inspection activity performed by the Supplier and witnessed by the Purchaser's Inspector (e.g. pressure tests, performance, and NDE tests). Test reports and other documentation shall be submitted to Purchaser.

Examine **(E) -** Inspection activity performed by the Purchaser's Inspector (e.g. final visual and dimensional examination).

Required **(X) -** Documentation, which requires submittal to the Purchaser for review (e.g. Welding Procedures, Material Substitution Requests, Material Test Reports, procedures, NDE and other documentation).

1.4 A Pre Inspection Meeting is a review with the Supplier, prior to the start of fabrication, to insure understanding of the purchase order requirements, including project specifications, applicable codes, and all applicable inspection requirements.

1. The Purchaser's inspector will schedule a Pre Inspection Meeting at a Supplier's facility when the level of inspection is designated as Level 2 or higher.

2. It is mandatory that key Supplier personnel attend the Pre Inspection Meeting. The Purchaser's Inspector requests which key Supplier personnel are to attend when the meeting is scheduled and requests confirmation. The following is a list of Supplier personnel who must be present during the meeting.

- **a.** Quality Control Manager or designated representative.
- **b.** Engineer responsible for the order.
- **c.** Production Manager or designated representative.

Annex H
(informative)

Functional Diagrams

H.1 Single Point Positioning Control

As mentioned in 7.4.6.2, with the single point positioning control system neither fuel nor air flow is measured. Their required ratio is maintained by mechanically linking the air and fuel systems with a jackshaft. In practice single point positioning systems have a limited number of final control elements. Typically, one combustion air damper and one or two fuel flow control valves are linked to the jackshaft. Automatic air/fuel ratio trim control and/or FGR control may be incorporated into a single point positioning control system.

The following single point positioning control system functional diagrams are included in this annex:

H.2 Parallel Positioning Control

As mentioned in 7.4.6.3, a parallel positioning control system provides for simultaneous operation of the air flow control element and fuel flow control valve via separate actuators according to the firing rate demand signal developed by the master steam pressure controller. This system is the first level of improvement over the single point positioning control system. But like the single point positioning control, neither fuel nor air flow is measured, rather both are inferred by the position of the final control elements.

The following parallel positioning control system functional diagrams are included in this annex:

H.3 Fully Metered Control Systems

As mentioned in Section 7.4.6.4, fully metered control systems optimize combustion efficiency throughout the load range of boiler operation with air flow leading fuel flow during load increases and lagging the fuel flow during load decreases. Both fuel and air flows are measured (and not inferred as in the two previous systems) and the actual flow rates are used as feedback signals for closed loop control and are compared against the demand established by the boiler master steam pressure controller. Fully metered systems have many improvements over parallel positioning and single point positioning control systems.

The following fully metered control system functional diagrams are included in this annex:

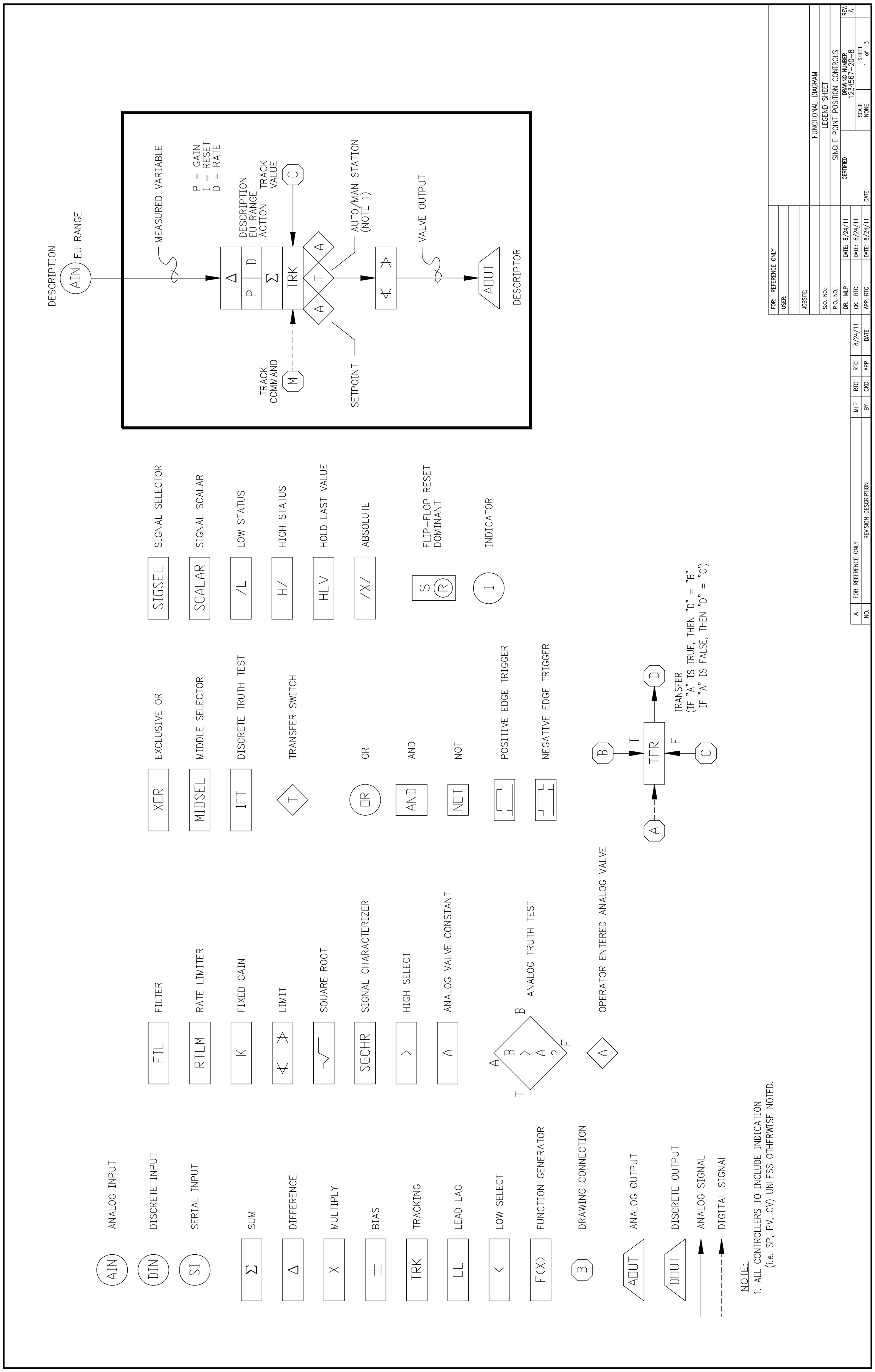

Figure H.1—Legend Sheet—Single Point Positioning Control

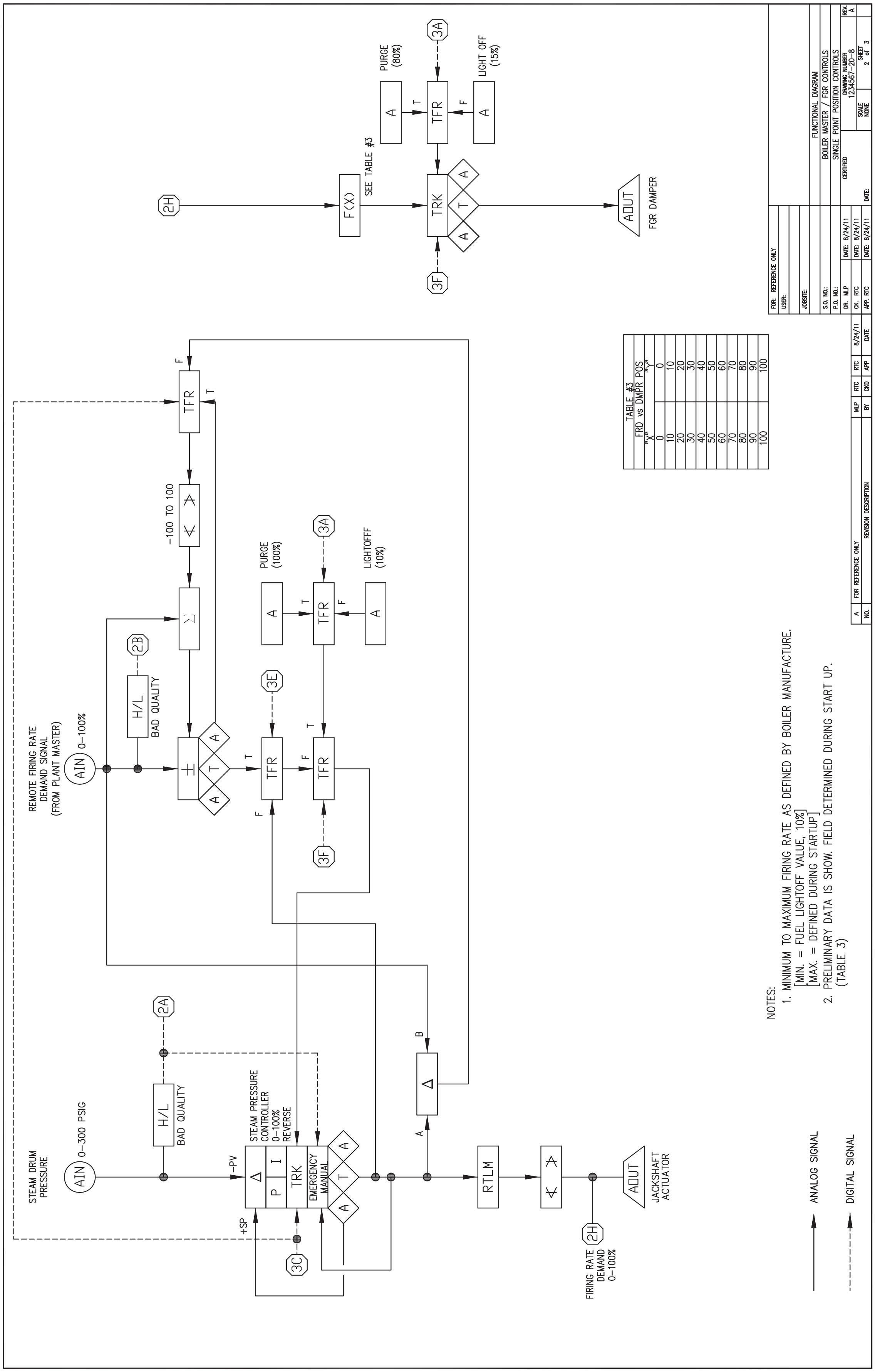

Figure H.2—Boiler Master/Flue Gas Recirculation Controls

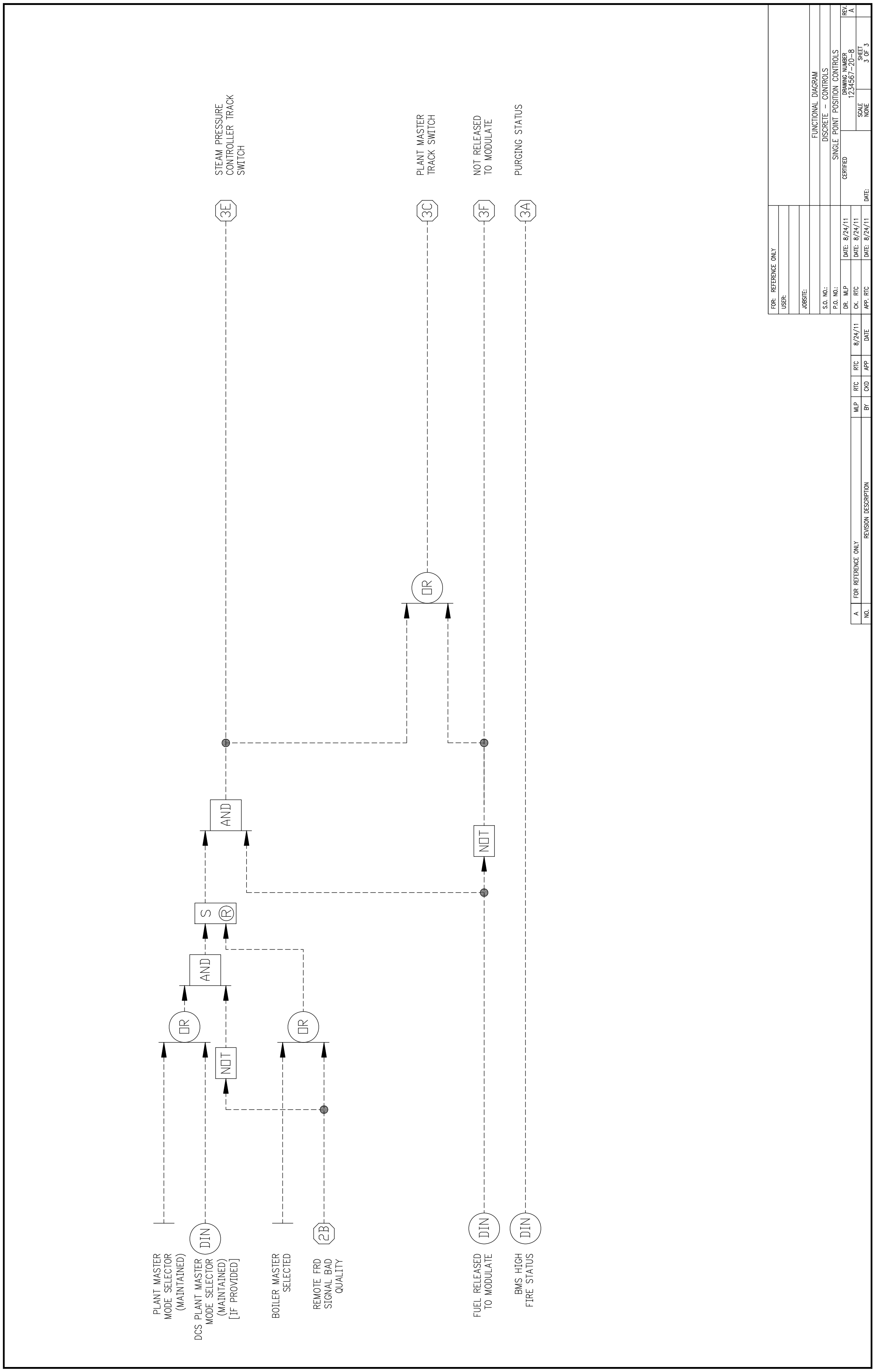

Figure H.3—Discrete—Controls

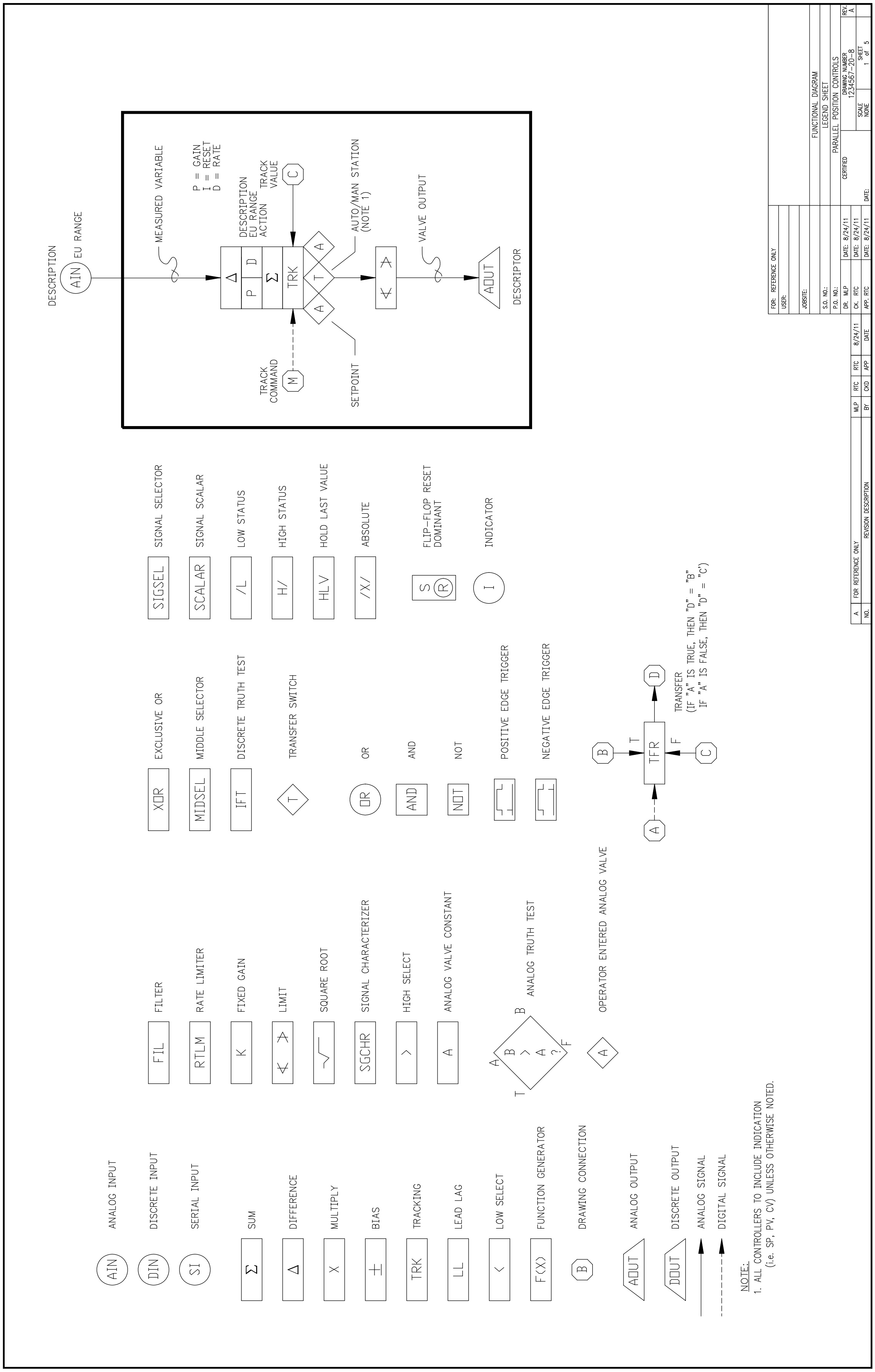

Figure H.4—Legend Sheet—Parallel Positioning Control

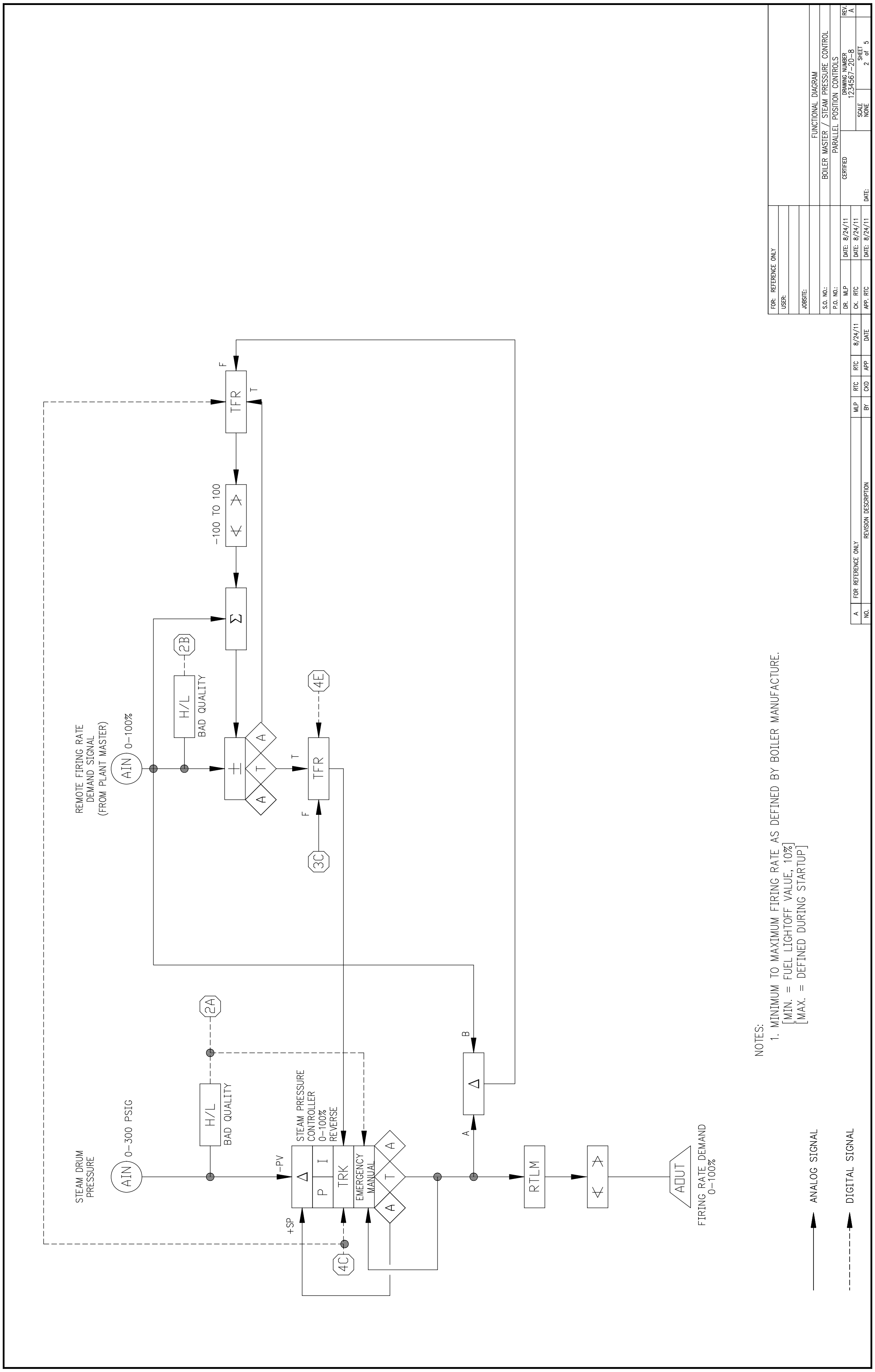

Figure H.5—Boiler Master/Steam Pressure Controls

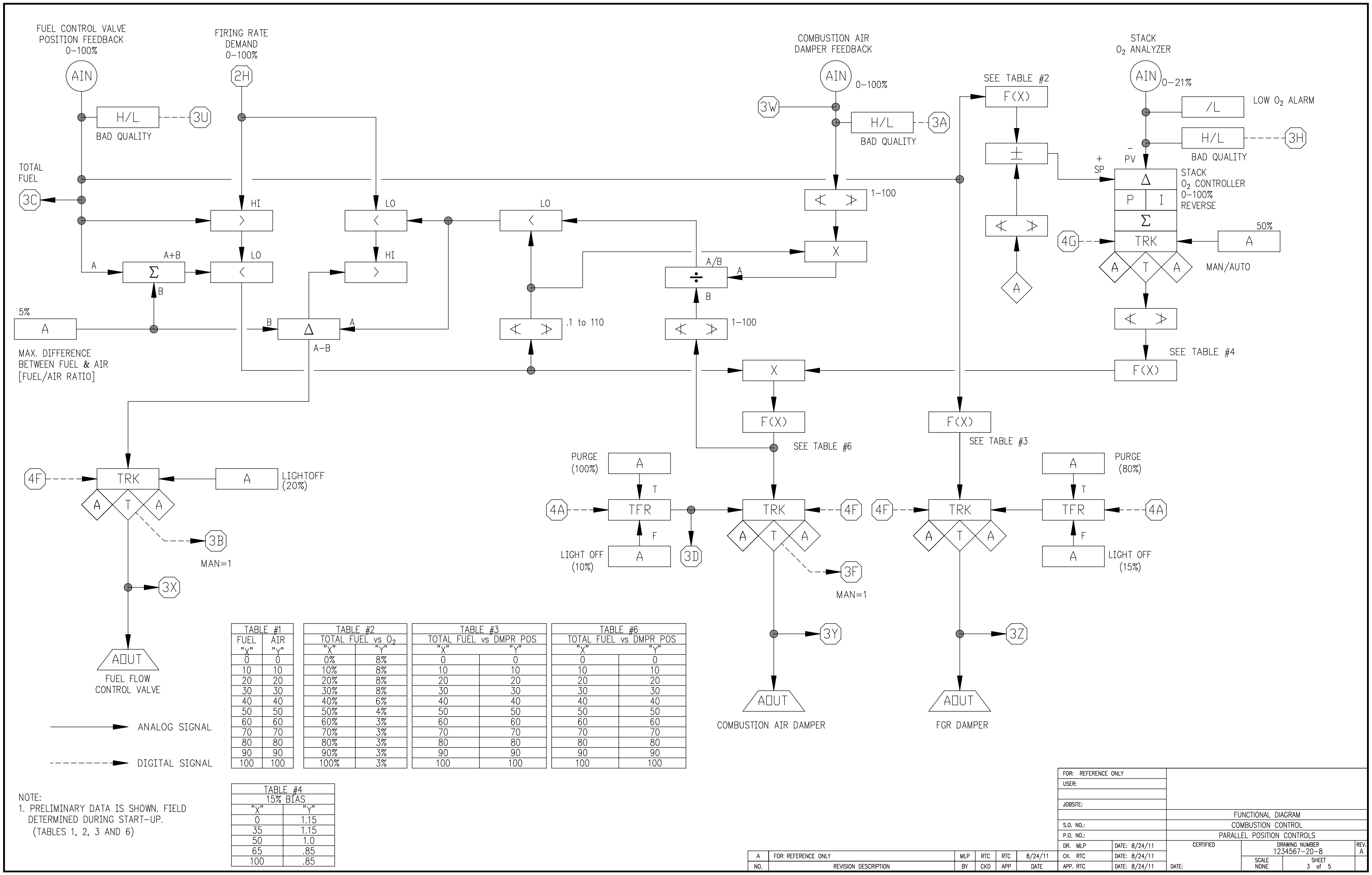

TABLE #1

FUEL "X"	AIR "Y"
0	0
10	10
20	20
30	30
40	40
50	50
60	60
70	70
80	80
90	90
100	100

TABLE #2 TOTAL FUEL vs O_2

"X"	"Y"
0%	8%
10%	8%
20%	8%
30%	8%
40%	6%
50%	4%
60%	3%
70%	3%
80%	3%
90%	3%
100%	3%

TABLE #3 TOTAL FUEL vs DMPR POS

"X"	"Y"
0	0
10	10
20	20
30	30
40	40
50	50
60	60
70	70
80	80
90	90
100	100

TABLE #6 TOTAL FUEL vs DMPR POS

"X"	"Y"
0	0
10	10
20	20
30	30
40	40
50	50
60	60
70	70
80	80
90	90
100	100

TABLE #4 15% BIAS

"X"	"Y"
0	1.15
35	1.15
50	1.0
65	.85
100	.85

NOTE:
1. PRELIMINARY DATA IS SHOWN. FIELD DETERMINED DURING START-UP. (TABLES 1, 2, 3 AND 6)

Figure H.6—Combustion Controls

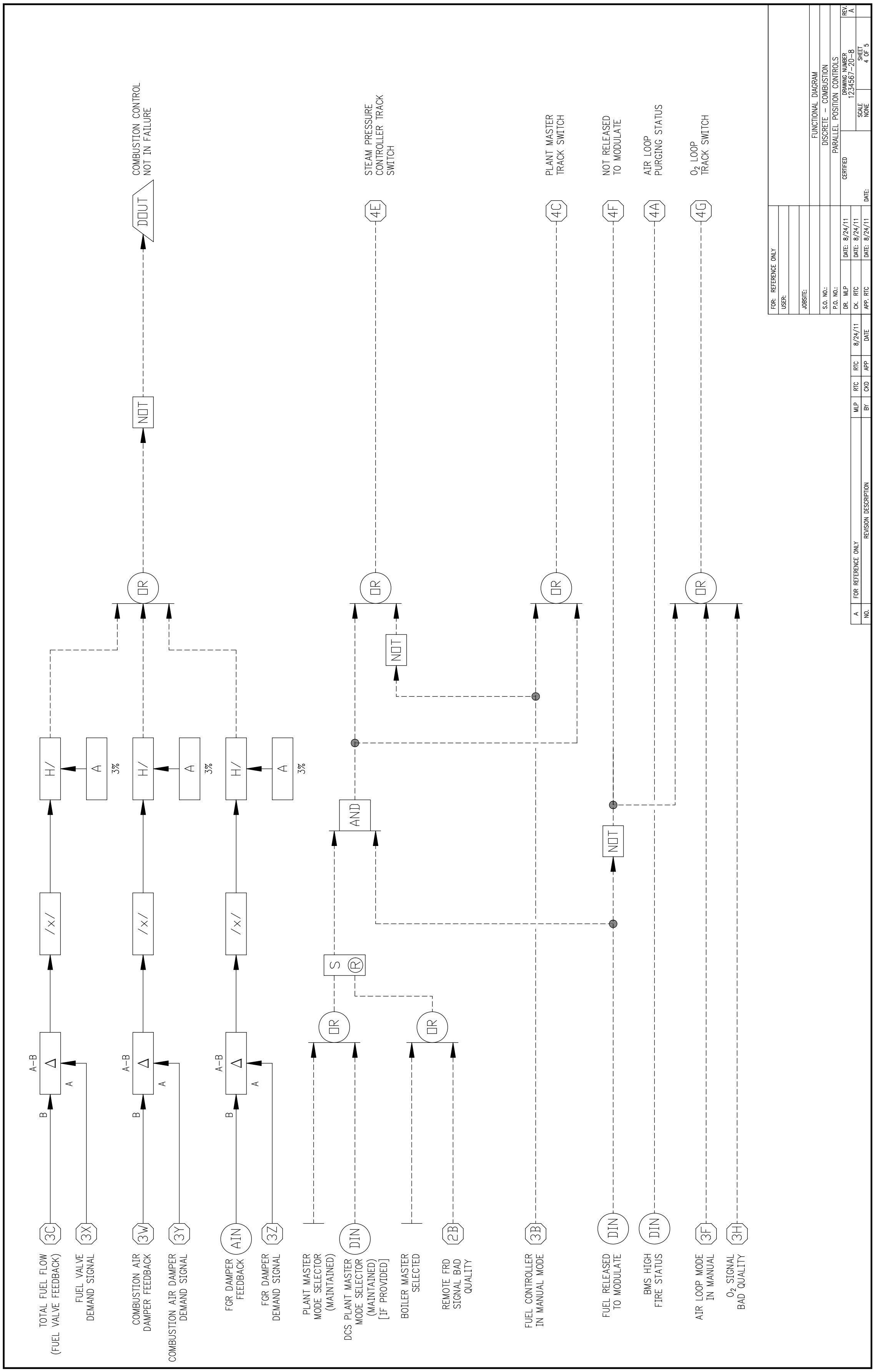

Figure H.7— Discrete—Combustion

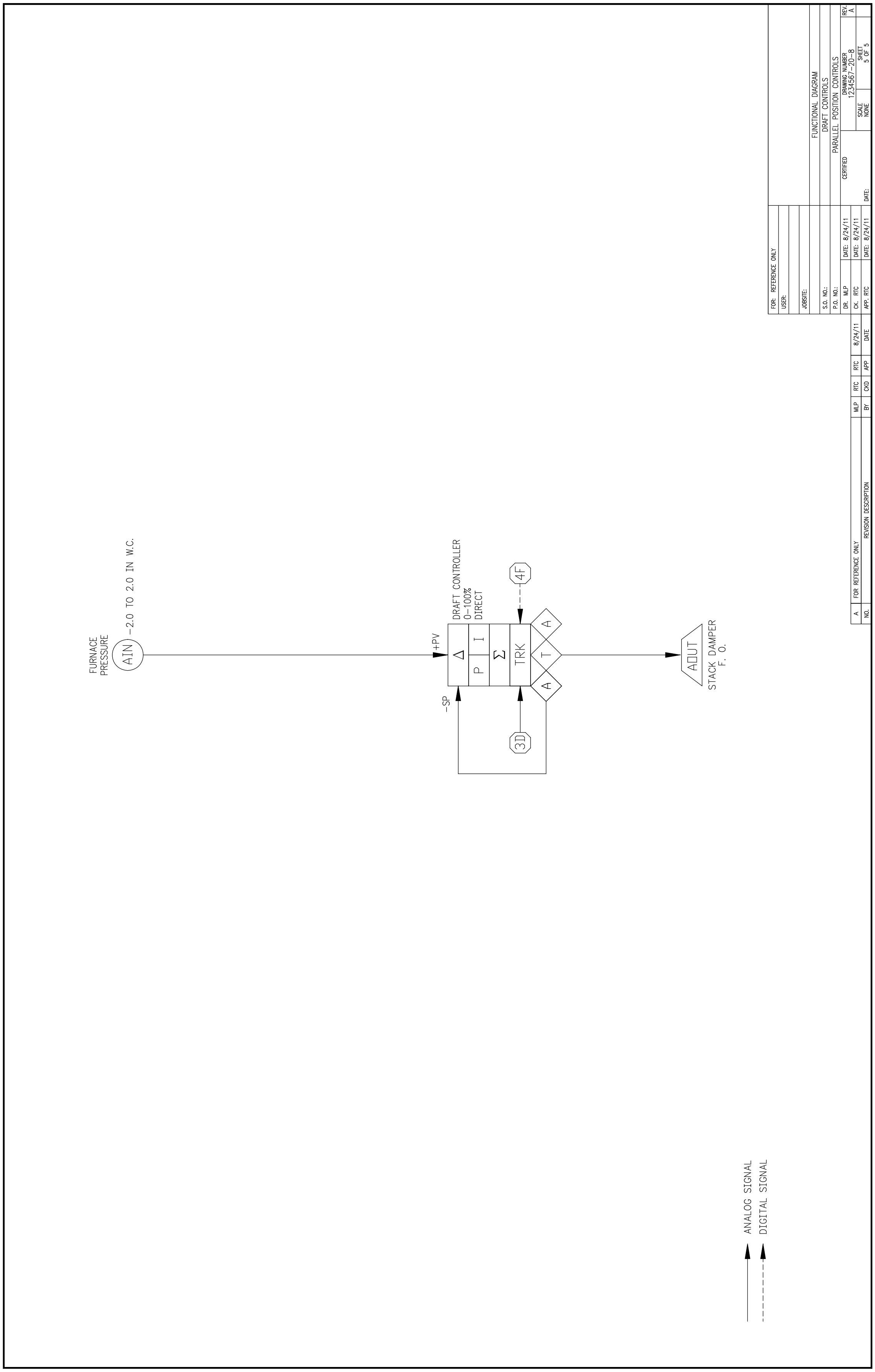

Figure H.8— Draft Controls

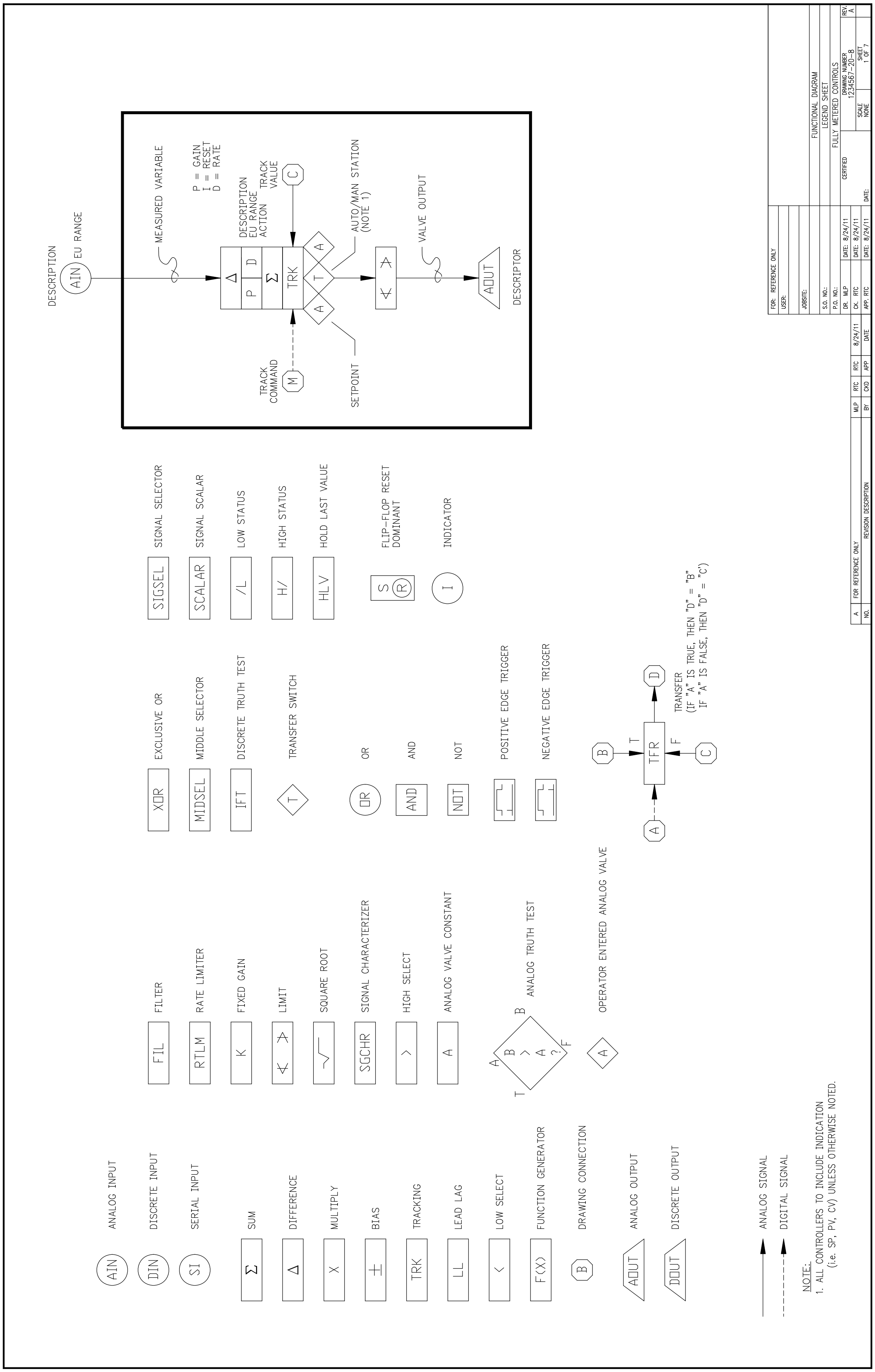

Figure H.9—Legend Sheet—Fully Metered Control Systems

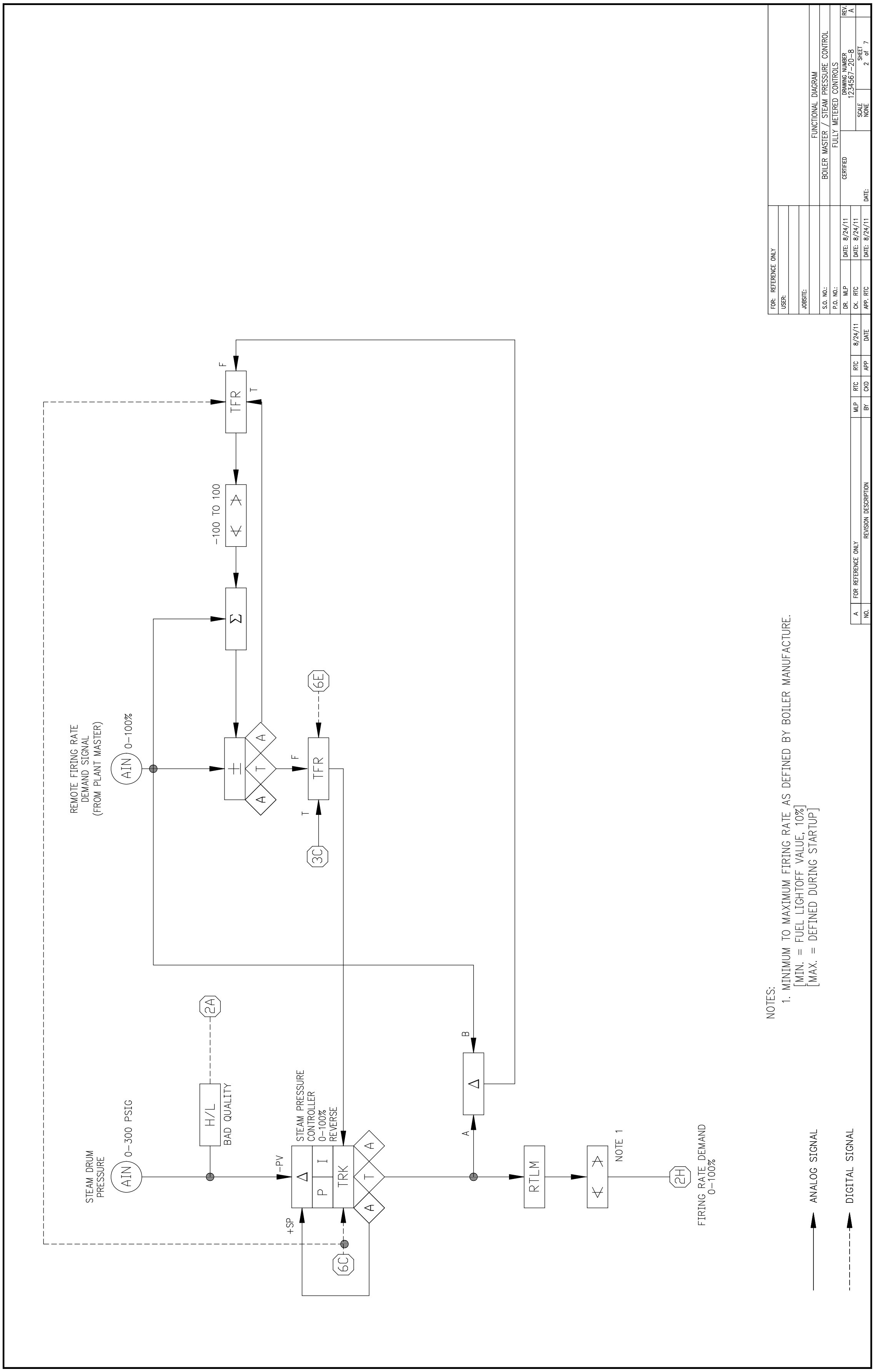

Figure H.10—Boiler Master/Steam Pressure Controls

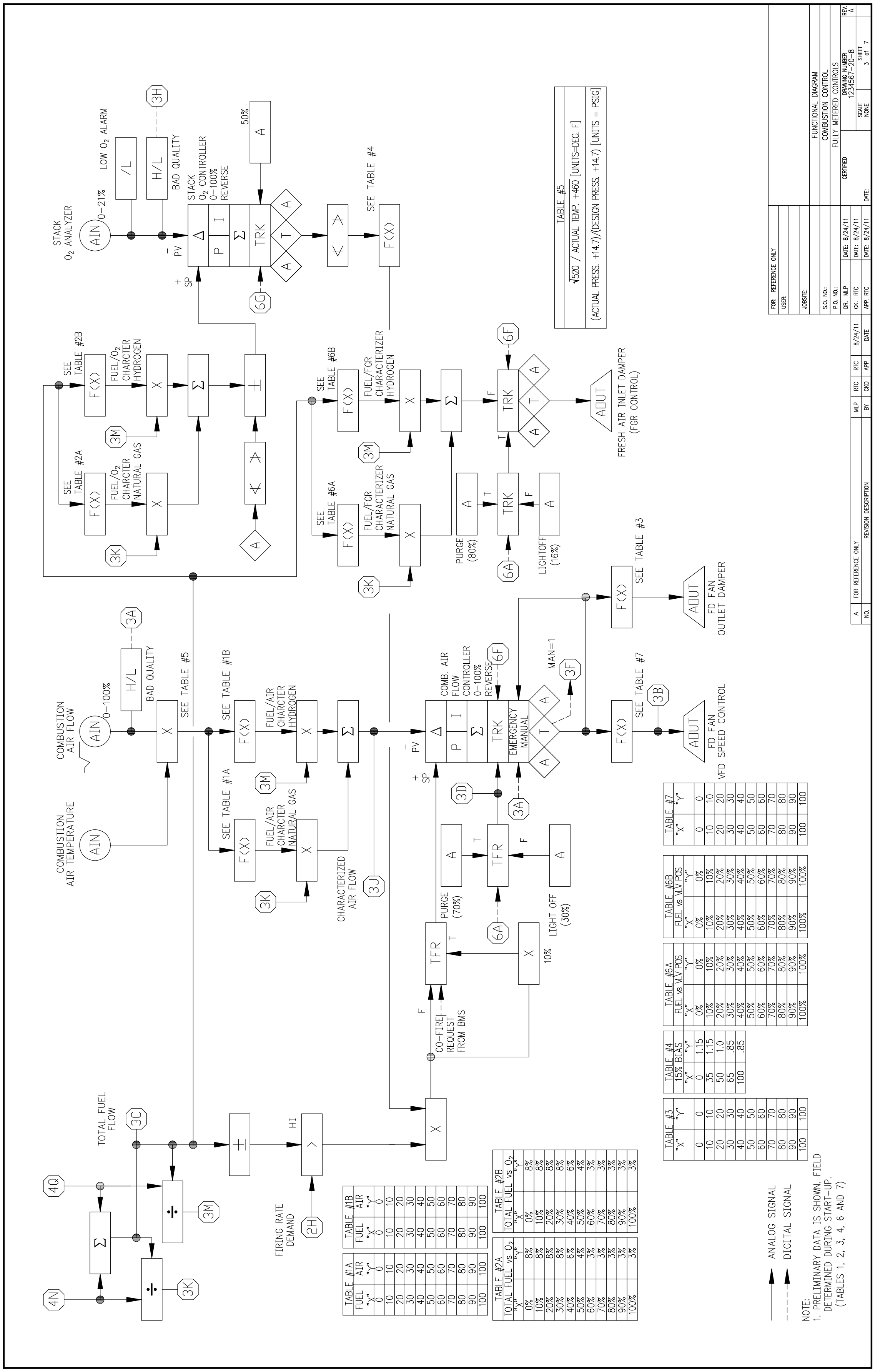

Figure H.11—Combustion Controls

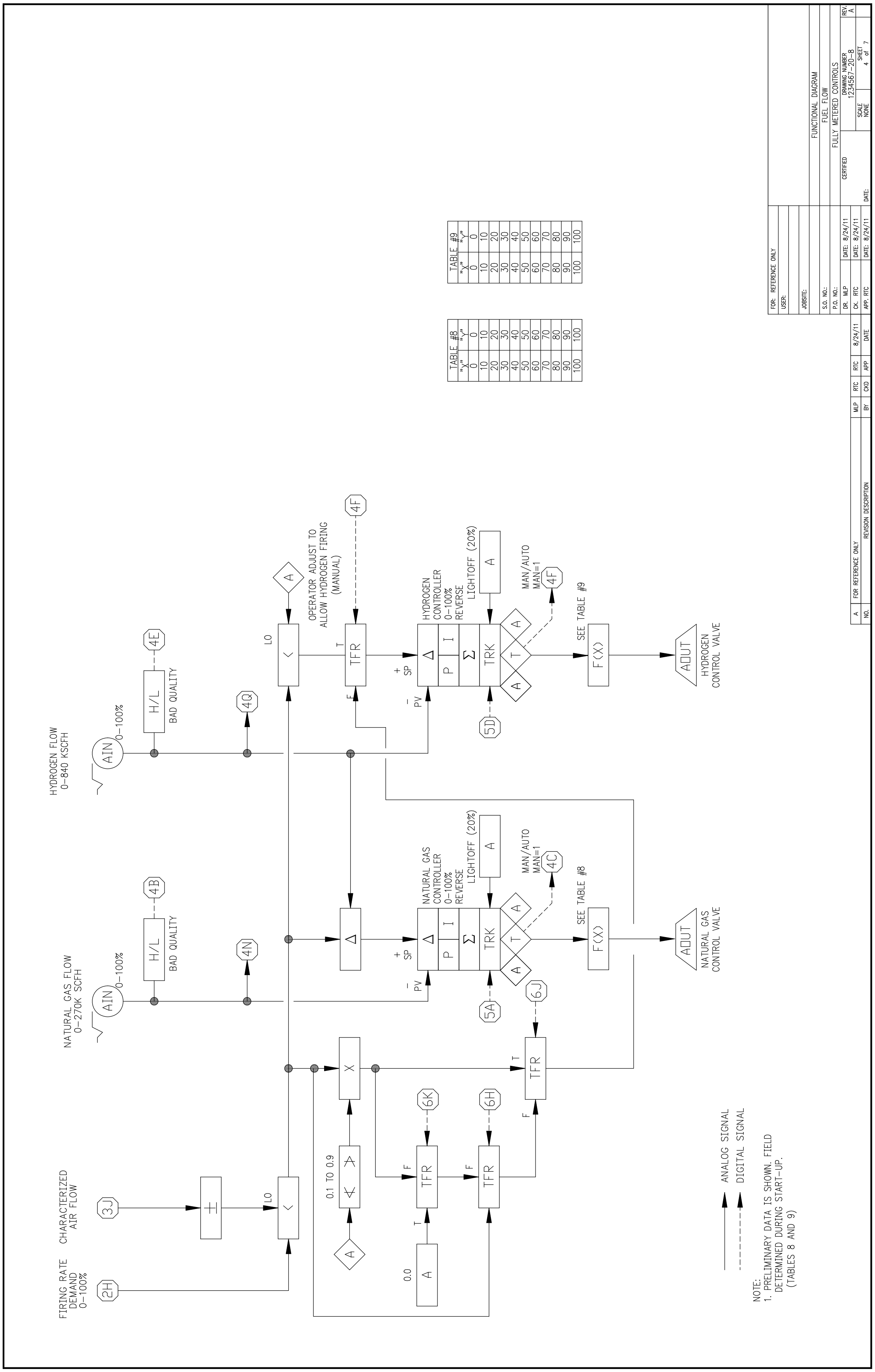

Figure H.12—Fuel Flow

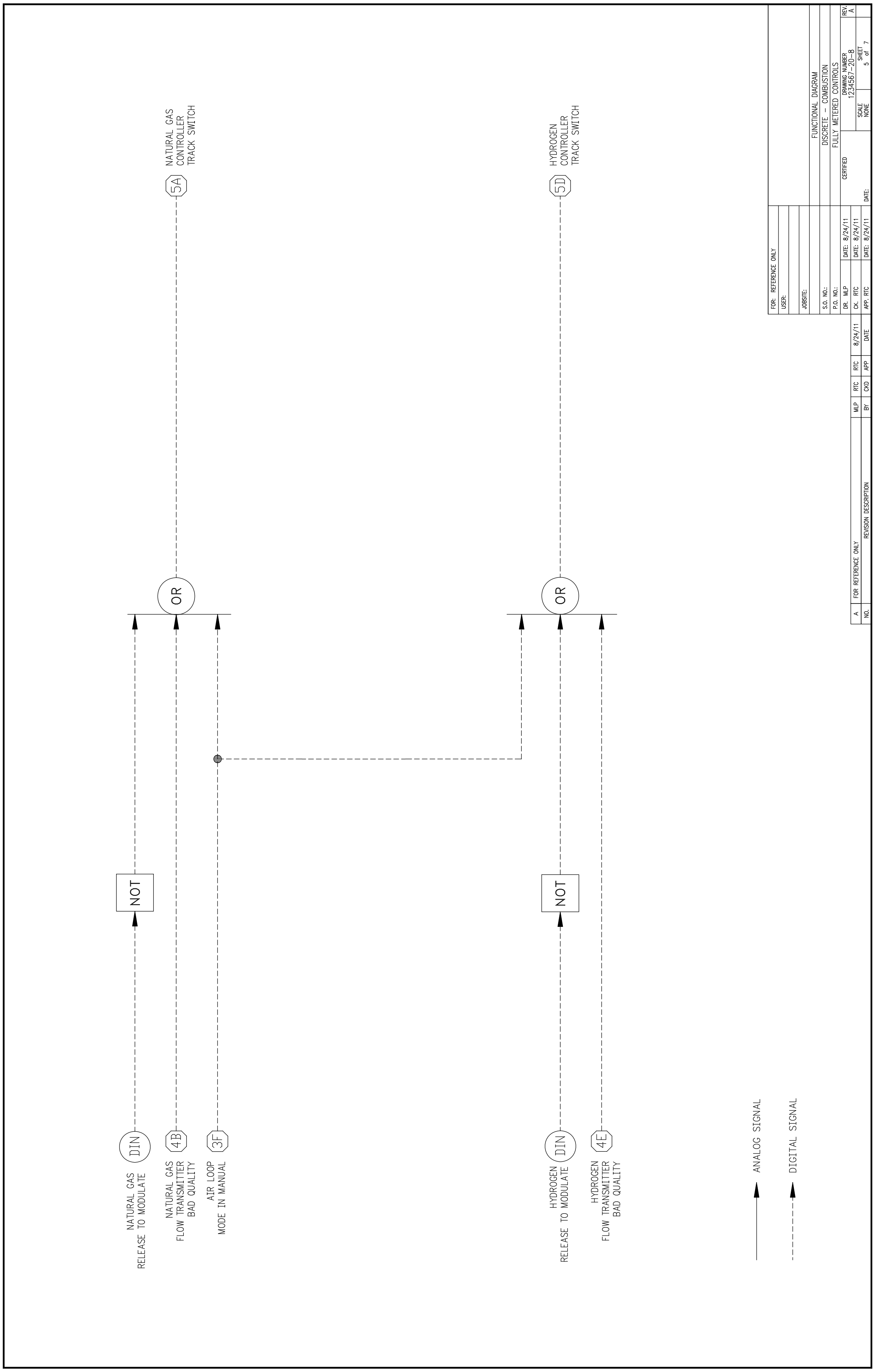

Figure H.13—Discrete—Combustion

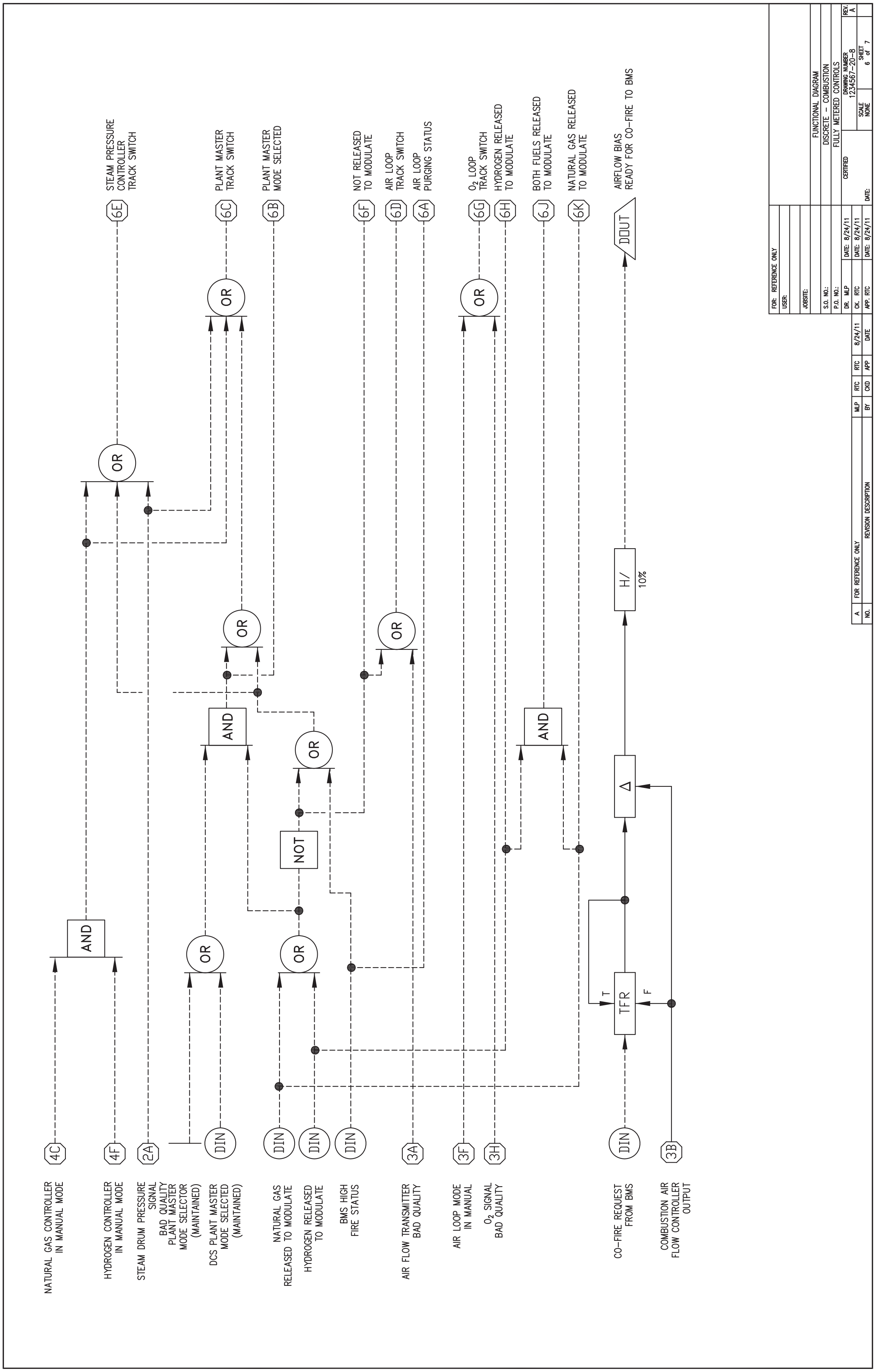

Figure H.14—Discrete—Combustion

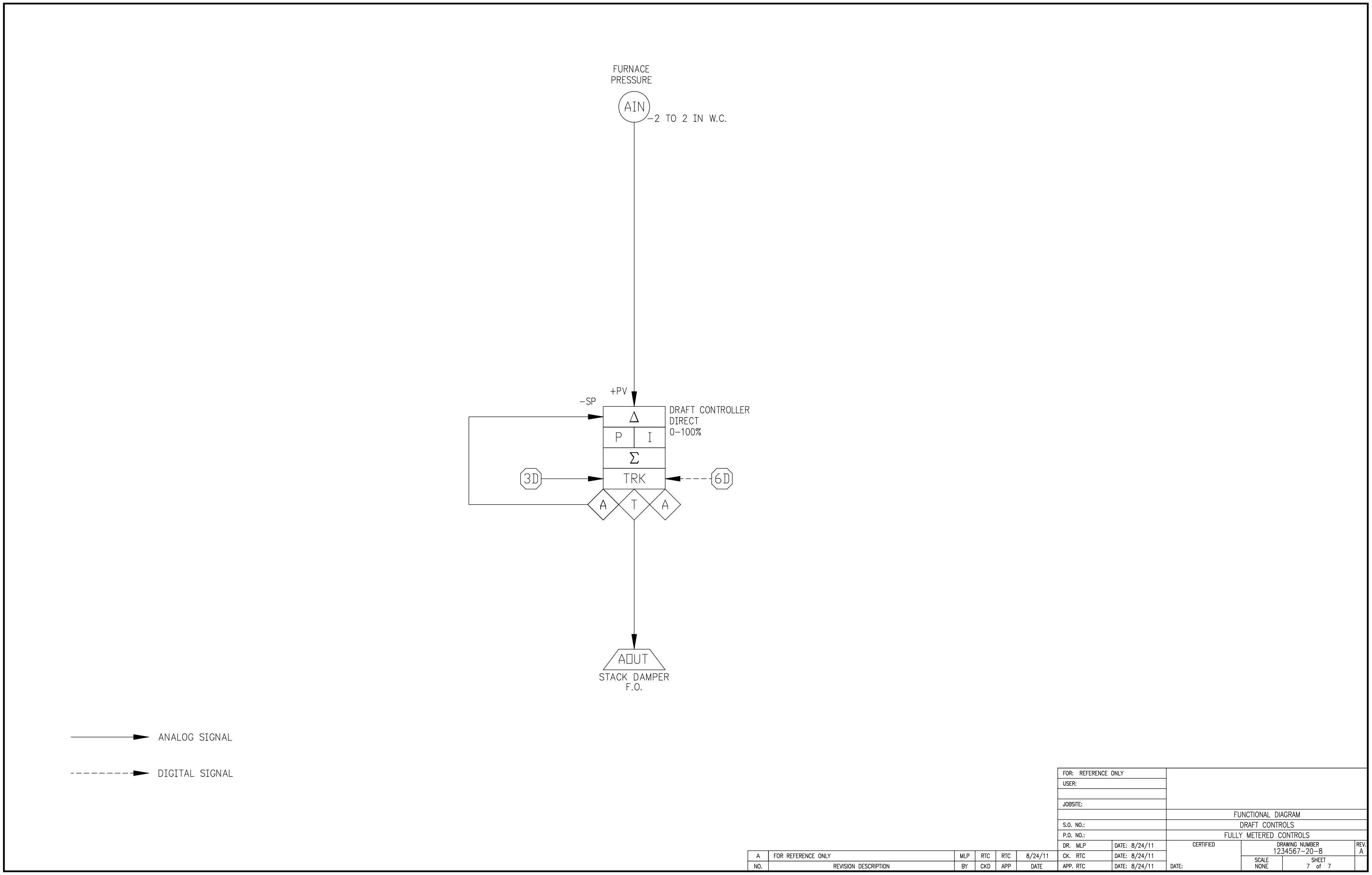

Figure H.15—Draft Controls

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