

 DESIGN PRACTICES	INSTRUMENTATION BOILER CONTROL	Section	Page
		XII-I	1 of 23
		March, 2004	

CONTENTS

Changes shown by ↕

Section	Page
SCOPE	3
REFERENCES	3
GLOBAL PRACTICES	3
OTHER REFERENCES	3
BACKGROUND	3
BASIC DESIGN CONSIDERATIONS	3
COMBUSTION CONTROL	4
COMBUSTION AIR RATE	4
METHODS OF CONTROLLING AIR RATE	4
NO _x CONTROL AND CONTINUOUS EMISSIONS MONITORING (CEM)	5
FIRING REFINERY GAS	6
COMBINED GAS / OIL FIRING WITH PREFERENTIAL GAS FIRING CONTROLS	6
ATOMIZING STEAM CONTROL	7
MINIMUM FIRING CONTROLS	7
OVERFIRING PROTECTION	7
BASE-LOADED BOILER	8
LOW-BTU GAS / FUEL GAS FIRING WITH PREFERENTIAL LOW-BTU GAS FIRING CONTROLS	8
FEEDWATER CONTROL	8
SINGLE-ELEMENT FEEDWATER CONTROL	8
THREE-ELEMENT FEEDWATER CONTROL	8
OPERATION AND PROTECTION	9
BOILER OPERATION AND BURNER LIGHTOFF / SHUTDOWN	9
LOCAL CONTROL PANEL	9
PROCESS VARIABLE MEASUREMENT	9
BLOWDOWN	9
PROTECTION OF BOILER AGAINST LOSS OF ELECTRICAL OR PNEUMATIC POWER	10
MISCELLANEOUS	10
EQUIPMENT SELECTION	10
TYPICAL BOILER CONTROL SCHEME	10



Documents

Document Sharing Hub

Section XII-I	Page 2 of 23	INSTRUMENTATION BOILER CONTROL	ExxonMobil DESIGN PRACTICES
March, 2004			

TABLE

Table 1 - Minimum Recommended Boiler Control Instrumentation	11
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FIGURES

Figure 1 - Typical Air Flow Requirements	12
Figure 2 - Fuel / Air Ratio Control System.....	13
Figure 3 - Fuel / Air Ratio Control System for Fuel Gases With Wide Fluctuations in Density and No Inerts Present.....	14
Figure 4 - Fuel / Air Ratio Control System for Fuel Gases With Wide Fluctuations in Heating Value and Inerts Present.....	15
Figure 5 - Combined Gas / Oil Firing System With Preferential Gas Firing Controls.....	16
Figure 6 - Combined Low-Btu Gas / Fuel Gas Firing System With Preferential Low-Btu-Gas Firing Controls.....	17
Figure 7 - Three-Element Feedwater Control System.....	18
Figure 8 - Typical Fuel / Air Ratio Control System	19
Figure 9 - Typical Boiler Lightoff / Shutdown Logic for Dual Fuel Boilers.....	21
Figure 10 - Typical Boiler Lightoff / Shutdown Logic for Single Fuel Boilers	22

Revision Memo

- 03/04** General revision with the following prominent changes:
1. Reference to NFPA code added
 2. Type of Oxygen/CO Analyzer changed
 3. Minimum requirement for head type flow meter.
 4. Fail Action requirements of the main control valves specified.
 5. Requirements for Critical Instrument Air supply.
 6. Minimum firing control requirements for low NOx burners
 7. Fuel Gas Control valve Bypass valve Tight Shutoff requirement has been deleted . All Boiler fuel gas shutdown systems have double block and bleed as per NFPA requirements and they are downstream of the Control and bypass valves.
 8. Note added to drawings to indicate that the symbology used is indicative only.



ExxonMobil DESIGN PRACTICES	INSTRUMENTATION BOILER CONTROL	Section XII-I	Page 3 of 23
		March, 2004	

SCOPE

This section is a practical guide to the selection and application of combustion and feedwater control systems for boilers. These systems, as discussed in this section, are applicable to drum-type stationary boilers, whether field-erected or packaged, and to marine boilers. The recommendations herein apply to single boiler installations, as well as to multiple boiler installations operated from a master steam pressure controller. Cogeneration facilities are not covered by this practice.

It should be recognized that the cost of such control equipment may be excessive for small boilers (e.g., less than about 20 tons/hr.), forcing the designer to seek more economical methods of control. For control of small boilers, the Control Systems, Measurement & Automation Projects Section of EMRE / AOD should be consulted.

REFERENCES

GLOBAL PRACTICES

GP 1-1-1,	Drawings, Diagrams and Line Lists
GP 7-2-1,	Industrial Boilers
GP 15-7-2,	Protective Systems
GP 15-7-3,	Alarm Systems
GP 15-11-1,	Instrument Control Panels
GP 16-8-1,	Instrument Power Supply

OTHER REFERENCES

1. Mohr, S.C., *Preheater Fire Protection Guidelines*, ER&E Report No. EE.53E.83.
2. Christensen, K., Brewer, N.L., Matta, G.M., Benson, C.E., *Furnace and Boiler Combustion Optimization*, ER&E Report No. EE.99E.80.
3. NFPA 85 Boiler and Combustion Systems Hazards Code

BACKGROUND

The purpose of a boiler is to make steam from water condensate and boiler feedwater. This is typically done in a closed loop circuit where the condensate is collected from the steam users and returned to the boiler, and the boiler feedwater is used to make-up for steam / condensate losses and blowdown operations. Steam is used primarily as a heat transfer medium, but it may also be used directly in a process for functions such as product stripping or reaction quenching. All boilers require both combustion and feedwater controls to meet the demand of the plant facilities and to ensure safe operation of the equipment. The selection and application of combustion and feedwater controls will be based primarily on the plant steam requirements and the fuels available. Dedicated instruments and burner management systems are provided for equipment protection.

The purpose of automatic feedwater control is to maintain the water availability as conditions change (either rapidly or slowly), such that the boiler drum does not flood or run dry. The purpose of combustion control is to provide the proper magnitude of firing to respond to the steam demand. The ability of a boiler to operate properly and respond effectively over wide variations in plant demand and fuel composition depends on the proper application of these interrelated / interacting controls.

BASIC DESIGN CONSIDERATIONS

The boiler combustion and feedwater control systems must be designed to perform the following functions:

- Maintain steam production at the required conditions under varying plant operations, with a minimum amount of supervision.
- Maximize combustion efficiency and safety by maintaining the desired air / fuel ratio during all steady state and transient firing conditions.

Section XII-I	Page 4 of 23	<i>INSTRUMENTATION</i> BOILER CONTROL	 DESIGN PRACTICES
March, 2004			

COMBUSTION CONTROL

Steam header pressure is in general the primary variable to be controlled by the combustion control system. The output of a steam header pressure controller establishes the set points for the combustion controllers. In multiple-boiler installations one (master) steam pressure controller serves as the primary control for a group of boilers. Operating strategies on multiple boilers often have one unit on maximum firing, one on minimum firing and one taking the swing or steam header controlling. The boiler on minimum firing is set to ramp up firing in the event of a boiler trip or demand increase.

COMBUSTION AIR RATE

Most burners used in refinery boilers require 10 to 15% excess air in order to operate efficiently and have suitable flame patterns. Air requirement is not directly proportional to firing rate. As can be seen in [Figure 1](#), air flow requirement does not approach zero as firing rate approaches zero. Instead, the air requirement curve can be approximated by a straight line with a positive intercept on the Y-axis (representing a minimum "excess air" requirement at zero firing rate).

To satisfy these requirements in the control system, a ratio plus bias device is used in the air flow measurement signal line. The bias is used to compensate for the offset characteristic of the air requirement; the ratio function establishes the slope of the approximating straight line, to provide for the most effective percent excess air. The design must also include means for setting the minimum air flow, which is required for good mixing of fuel and air at the burners.

Since excess air in the flue gases must be kept within certain limits, it is recommended that the flue gas from each boiler be monitored by direct measurement of its oxygen content. The oxygen analyzer should be monitored and recorded in the central control room, where it will enable the operator to check and adjust the ratio plus bias settings discussed above. A low oxygen alarm is required to warn the operating personnel when the oxygen level approaches unsafe low limits.

Automatic control of excess air in the flue gas may be necessary when minimum excess air is required for efficient boiler operation. Oxygen control is also important to maintain proper excess air when more than one fuel is being fired and when fuel gas density and heating value can vary widely. The output of the oxygen controller must have an adjustable output limiter, or equivalent, to prevent the oxygen controller from driving the fuel/air ratio below stoichiometric conditions when a faulty signal is received from the analyzer.

The type of oxygen analyzer recommended for boiler applications is the close-coupled extractive type utilizing a zirconium oxide sensor. It shall be equipped with a catalytic detector for measuring combustibles such as CO or unburned hydrocarbons. Currently only the Class I / Div II / Zone 2 version of the Ametek (Thermox) WDG-IVC is recommended for this application unless there is a requirement by the local legislative body to install a dedicated CO analyzer. Refer to GP 7-2-1, Par. 6.12, GP 15-6-1, and GP 15-8-1 for specific equipment requirements.

The primary flow element for measuring combustion air flow rate can be a conventional head device or venturi section in the inlet duct. If the head device used for air flow measurement is a pitot device it shall be of the averaging array design. Regardless of the head type instrument type selected, it must generate a minimum of 6" H₂O ΔP at 100% Maximum Continuous Rating (MCR) firing rate and 10% excess air.

For boilers having fewer than 4 burners, individual burner automatic registers are sometimes used to simplify light-off and to redistribute the air flow on loss of burner(s); thus eliminating localized fuel rich pockets and long flames.

METHODS OF CONTROLLING AIR RATE

There are two basic combustion control systems that have been used for refinery boilers: steam/air ratio control and fuel/air ratio control. Of these, only the latter is recommended, for the reasons given below.

Steam / Air Ratio Control - This method is useful where the accuracy of the fuel flow measurement is unreliable, such as for firing solid fuels. However, this control scheme has several drawbacks: it is not as effective as fuel / air ratio control for maintaining the correct fuel / air ratio during transients; tuning of the required one-way derivative control component is difficult; and automatic safety cutback is not as easy to implement and not as positive as with fuel / air ratio control. Therefore, steam / air ratio control should not be considered for process plant boilers.

 DESIGN PRACTICES	INSTRUMENTATION BOILER CONTROL	Section	Page
		XII-I	5 of 23
		March, 2004	

Fuel / Air Ratio Control - This method is recommended as the basic combustion control system for all process plant boilers, regardless of the type of fuel used. This system provides automatic cutback circuits to safely maintain the desired fuel / air ratio under transient and steady state conditions.

A basic fuel / air ratio control system is shown in [Figure 2](#). The output of the master pressure controller adjusts (via high and low signal selectors) the set points of the air and fuel flow controllers. These two controllers are linked together in such a way that a certain ratio between the fuel and air is controlled, to maintain the correct combustion mixture. This ratio should be set to give a small amount of excess air for efficient and safe combustion.

Air/fuel controls must be configured and tuned to keep the boiler away from exceeding the stable excess air rate during transients. The high and low signal selector algorithms assure that this excess air is maintained during transient conditions. This is referred to as "cross-limiting control." On a load increase, the selector algorithms assure that air flow is increased before the fuel can be increased. Likewise, on a load decrease, the selector algorithms assure that fuel is cut down before air flow can be decreased. Thus, the boiler is protected against an unsafe fuel-rich combustion mixture, even during rapid load changes or upon loss of air fan capacity.

- ◆ To ensure boiler safety, air flow damper(s) should be specified with fail stationary with spring action to open, fuel valves with fail stationary with spring action to close, feed water valve fail stationary with spring action to close and atomizing steam fail stationary with spring action to open in the event of air supply or control signal loss to the actuators. Instrument air to all critical boiler instruments shall be supplied via a dedicated receiver. The receiver shall be sized to deliver the air requirement of all boiler controls and shutdown valves for a minimum of 30 minutes.

Fuel flow meter(s) should be equipped with dual transmitters (using separate meter taps) to reduce the probability of loss of flow measurement. The measurement system operates on the higher of the fuel flow signals, as determined by a high signal selector. This redundancy will prevent the fuel valve(s) going wide open no matter what the mode of a transmitter failure. Smart transmitters shall be configured to soft-fail low. For single -burner boilers, the fuel control valve shall be located downstream of the trip valves.

- ◆ Fuel gas flow measurement and control capability must be consistent with the desired turn-down and fuel flexibility requirements. For high turndown and/or wide-ranging fuel composition applications, this may require dual flow meters or parallel control valves. For varying fuel gas composition applications, analyzers may be required to correct for molecular weight or specific heat.

This system provides proper combustion control for fuels of relatively constant composition. However, fuel gas is often obtained from a plant waste gas system, and its composition may therefore fluctuate considerably. If fuel molecular weight and calorific value are not reasonably constant, a more complex system, which will compensate for these changes, should be employed (see below).

NO_x CONTROL AND CONTINUOUS EMISSIONS MONITORING (CEM)

Continuous Emissions Monitoring Systems (CEMS) are typically required for regulatory compliance as well as emissions management. They can also be used to improve various aspects of boiler performance in addition to lower operating costs. These systems can be designed to continuously measure any number or all of the following components and properties of the stack gases : O₂, CO, CO₂, SO₂, NO, NO_x, total hydrocarbon and opacity. Affiliate practices, as well as the local regulatory requirements, should be used to determine the stack monitoring and control requirements for specific boiler applications.

- ◆ NO_x control is achieved by low NO_x burners, steam or water injection into the firebox , flue gas recirculation or selective catalytic reduction (SCR). All these methods have their own impact on the overall boiler control requirements.



Section XII-I	Page 6 of 23	<i>INSTRUMENTATION</i> BOILER CONTROL	 DESIGN PRACTICES
March, 2004			

FIRING REFINERY GAS

In most refinery boiler applications, economic, environmental or other considerations require the use of refinery gas as a fuel. Refinery fuel gas often undergoes significant fluctuations in molecular weight and heating value. If the fuel gas density changes are slow and infrequent, then direct automatic compensation is usually not required. For example, when a boiler is firing paraffinic fuel gases and operating with normal (constant) excess air, the combustion air will still be above stoichiometric conditions with a fuel gas density increase up to about 40%. (A decrease in fuel gas density at constant air rate increases the % excess air.) With an oxygen analyzer automatically adjusting the ratio, the control system could handle density changes to + 100%.

On the other hand, if the density changes are too wide, rapid, or unpredictable, it may be necessary to include a density analyzer, as shown in [Figure 3](#), to correct for these changes. There are no general rules for determining when a density analyzer is required. For each application, the combustion air requirements must be calculated over the probable range of fuel gas variation to verify that the control system is adequate. In most cases, wide variations resulting from startup, winter, summer or other unusual operating conditions can be handled by manual adjustments of the fuel / air ratio.

The combination of a volumetric flow meter and a density analyzer on the refinery gas line gives a measurement of mass flow rate. For paraffinic fuel gases, the calorific value has a small variation over the normal density range. Therefore, mass flow rate is an adequate indication of heat fired. However, if there are inert gases present and wide fluctuations in heating value, then the above approach may not be sufficient, and it may be necessary to employ a Wobbe Index analyzer in place of the density analyzer, as shown in [Figure 4](#).

This Wobbe Index can be continuously measured and hence provides direct measurement of Btu flow to the burner, making control of the burner accurate and reliable. The fuel gas flow signal (SCF) is multiplied with the output of the Wobbe Index analyzer, which takes into account both the density and calorific value (LHV) of the gas (assuming constant temperature and pressure). Wobbe Index measures the ratio between the calorific value and the square root of specific gravity:

$$\frac{LHV}{\sqrt{\text{gas specific gravity}}}$$

Multiplying this with the square root of the differential pressure from the volumetric flow transmitter, will result in a signal that is proportional to the heat input in Btu/hr to the boiler. The air requirement per Btu is reasonably constant and no additional corrections are required. An analyzer specialist should be consulted for the application and equipment requirements of this type analyzer.

COMBINED GAS / OIL FIRING WITH PREFERENTIAL GAS FIRING CONTROLS

In many refinery boiler applications, economic or other considerations may require combined gas / oil firing capabilities. In some cases, combined firing of fuel oil and natural gas may be made desirable by seasonal price fluctuations. In most situations, however, combined firing results from the use of refinery gas as the main (or preferential) fuel to the boiler and the need for an auxiliary fuel when available refinery gas is not sufficient to meet boiler needs. This auxiliary fuel is usually fuel oil.

Very often the boiler fuel gas controls are part of the plant fuel gas header pressure control system. As with the steam header control in a multiple boiler situation, one boiler is typically used as the swing boiler for fuel gas header control with the other boilers running on base/fixed load. Effectively, the boiler can be thought of as a control valve for the fuel pressure control. Using a dual fuel (fuel gas/fuel oil) boiler as a means of controlling fuel gas header pressure is typically more economical than using other strategies like LPG vaporisers. Gas is fired when it is available; however, if the gas header pressure drops, the gas firing is automatically cut back and oil is used as a supplementary fuel. Smooth transition from oil to gas or to any combination of gas / oil firing is mandatory if proper steam production and safe boiler operation are to be accomplished.

The recommended preferential gas firing system, having two flow controllers set by the master steam pressure controller, is shown in [Figure 5](#). The oil and gas flows are added and their sum is the total fuel (or Btu) input to the boiler. Flowmeter ranges for gas and oil should be selected such that equal input signals to the summing algorithm represent equivalent heat inputs (Btu/hr). For fuel gases with wide composition changes, density or Wobbe Index compensation as described previously may be required. Normally, when refinery gas is available, the master steam header PC output signal will set the fuel gas (refinery gas) FC.

ExxonMobil DESIGN PRACTICES	INSTRUMENTATION BOILER CONTROL	Section XII-I	Page 7 of 23
		March, 2004	

The two subtractors, as shown in [Figures 5](#) and [8](#), are employed to provide considerable loading flexibility and yet maintain safe operation at all times. Output H from the $H = E - G$ subtractor represents the difference between the requested firing rate and that portion of firing being maintained by fuel oil (either by manual loading, minimum firing, or normal swinging). This signal then passes through the low signal selector, assuming there is adequate gas available, to adjust the set point of the gas flow controller. Output F from the $F = E - D$ subtractor (with low signal limiting to avoid negative outputs) establishes the set point of the oil flow controller by computing the difference between total fuel demand and the gas availability signal, which assures that gas will be the preferential fuel under both increased and decreased demand conditions.

If the gas flow control is placed on manual control, it is necessary to automatically make signal D the actual gas flow signal, as indicated in [Figures 5](#) and [8](#). This requires no further operator attention to boiler controls, (i.e., the boiler controls automatically maintain safe design basis combustion conditions during manual manipulation of any one fuel). Even with manual control of both fuels, the automatic control of combustion air maintains safe design basis combustion conditions.

When the fuel gas system pressure drops, the gas PIC output decreases and at some point (when it drops below signal H in [Figures 5](#) and [8](#)) establishes the set point for the gas FC and thus reduces the gas flow. The available gas flow will then be smaller than that required by the master steam pressure controller, and the result is a decreasing signal at D, which will subsequently move up the set point of the fuel oil flow controller.

ATOMIZING STEAM CONTROL

Atomizing steam controls vary for different burner designs, but generally function by maintaining sufficient steam pressure or sufficient steam / oil differential pressure at the respective steam header or steam / oil headers. Details depend on burner and operational requirements, therefore they have not been included in [Figure 5](#).

MINIMUM FIRING CONTROLS

In order to maintain stable and therefore safe operation of oil and gas burners on low boiler loads, it is required that fuel gas and fuel oil valves be limited in their travel so that a minimum fuel firing rate is obtained in accordance with normal burner turndown ratios. A common method is to provide a signal limiter in the control signal to the control valve or minimum fuel is limited by separate direct acting pressure or flow regulator across the main control valve. For multi-burner boilers, however, the minimum firing should be set by the proportional-only pressure controllers shown in [Figure 8](#). This approach will maintain minimum firing independent of the number of burners in operation and independent of the fuel gas header pressure fluctuations. In addition, it will maintain uniform burner pressure during lightoff. To ensure safe operation the control valve must be confirmed closed for lighting the first burner on multi-burner boilers and in light-off position for single-burner boilers via position switches to the BMS.

In the case of Low NO_x or other high efficiency burners that operate at very low pressures there may be a requirement to use flow measurement for setting the minimum fuel firing. A review of the Burner Curve is recommended to achieve the best minimum fuel firing setting.

OVERFIRING PROTECTION

When in automatic operation, the boilers should be protected against overfiring caused by a sudden increase in steam demand. An easy way to accomplish this is to provide an output limiter on the master steam pressure controller. This approach is reliable when the fuel gas density and heating values are relatively constant or if a density analyzer or Wobbe Index analyzer is provided to correct for these fluctuations. The output limiter will automatically limit the set points of fuel oil / fuel gas flow controllers.

The bias functions in the auto / manual stations should be supplied as "negative only" bias. In this way, the maximum demand signal to a boiler is the limited master PC output. It should be noted that this system does not provide overfiring protection when in manual operation. Thus, steam high flow alarms shall be provided locally and remotely to denote an overfiring condition.

