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BOILER TUNE-UP GUIDE
FOR NATURAL GAS AND LIGHT FUEL OIL OPERATION
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Table of Contents

1) Boiler Tune-Up Guidebook Introduction

Steam systems consume a large portion of the energy used throughout the world. These systems are vital to the activities of a wide variety of operations and serve as the cornerstone for delivering thermal energy in many arenas ranging from heavy industrial sites, through power generation plants, and into commercial-residential systems. The central component of any steam system is the boiler. The operating cost of most boilers is generally very large and their potential impact on the environment is considerable. This situation demands stringent boiler management and optimization.

There are many avenues that can be explored and exploited to improve the operation, efficiency, and economics of steam systems. One of the most common and more fruitful avenues is to improve boiler efficiency (the fuel-to-steam energy conversion efficiency). This avenue encompasses many focal points and potential opportunities for improvement. One of the most profitable targets is to optimize the management of the fuel combustion process. This activity is often identified as a *boiler tune-up*. It should be noted that *boiler combustion tune-up* is one small part of steam system management and improvement—however, it is an essential part.

The term *boiler tune-up* can refer to many aspects of improving boiler operations. In this Guidebook the term *boiler tune-up* specifically refers to the activity of improving the boiler combustion process to the best performance practical based on the primary in-place equipment. A boiler tune-up activity is focused on ensuring that the combustion control system achieves the optimum amount of excess air throughout the operating range of the boiler. The optimum amount of excess air will result in the exhaust gases from the combustion process exhibiting minimal unburned fuel and minimal excess air while meeting the appropriate environmental regulations. The type of combustion control the boiler uses will significantly influence the minimum practical amount of excess air for a particular boiler load. As a result, this Guidebook discusses the common types of boiler combustion control.

This Guidebook is divided into eight specific sections. First, the general introduction section (this section) initiates the boiler tune-up discussions. The second section is a general discussion of boiler efficiency and the influence combustion control has on efficiency. A primary goal of a boiler tune-up is to improve, and even optimize, boiler efficiency with respect to combustion operations. However, as stated previously, combustion management is only one aspect of boiler efficiency control and boiler efficiency is only one arena of steam system management. Because boiler combustion tuning investigations require an understanding of typical combustion control methods, the basic control methods are discussed in the third section of the Guidebook. Fourth, this Guidebook identifies the typical field activities associated with tuning a boiler. Fifth, methods for evaluating the economic impact associated with tuning a boiler are presented. Generally, identifying the economic impact of a tune-up is not a simple case of monitoring a fuel flow meter before and after the tune-up procedures. Most commonly the operating conditions of the boiler are too variable to allow a side-by-side comparison to be effective. As a result, indirect techniques will be presented that will provide an accurate and repeatable analysis of the tune-up. Sixth, a basic discussion of the environmental impacts that can be expected with a boiler tune-up activity are presented. The seventh section provides general reference data that can be useful in boiler tune-up evaluations. The eighth section is a list of general references that may prove useful in tune-up activities.

It should be noted that this Guidebook is not intended to address boiler safety concerns. Specifically, flame safeguard and fuel delivery safeguards are not addressed. All boiler adjustments and modifications should be completed by qualified, experienced technicians. This Guidebook is intended to identify the primary parameters impacting a boiler tune-up—it is not intended to replace the equipment owner's manual or the knowledge base of a trained technician. The overarching purpose of this Guidebook is to provide the boiler owner the knowledge base to appropriately direct boiler tune-up and combustion management activities. This will allow the boiler owner to clearly define the scope of work the tuning technician will be tasked to accomplish. Additionally, this Guidebook is arranged to provide the boiler owner with evaluation techniques to identify the potential impacts of tuning activities and to set realistic expectations on these activities.

A common boiler tune-up involves several activities that follow in a logical order.

Step 1 Identify the equipment to be acted upon—type of boiler, type of fuel, burner data, combustion control equipment, in-situ instrumentation, required portable instrumentation, measurement locations, environmental regulations, and much more.

Step 2 Measure and record the as-found operating conditions of the boiler. This includes measuring and recording the operating parameters throughout the control range of the boiler. This is in reference to direct measurements and visual inspection of combustion related components and characteristics.

Step 3 Adjust the combustion relationship for the entire boiler operating range. This is the central focus of the tune-up activity—this reestablishes the air-fuel mixture for the operating range of the boiler. Performance characteristics are verified to be repeatable and are recorded to allow evaluation and comparison.

Step 4 Evaluate the fuel energy and cost impact of the tune-up. This step challenges the existing equipment to identify if modifications in tune-up frequency are necessary and if upgrading equipment is justifiable.

The principles identified in this Guidebook are applicable to all common fuels; however, only natural gas and light fuel oils are addressed specifically. This results from the fact that heavy fuel oils, coal, wood, and other fuels require significant auxiliary equipment and present additional complexity in the tuning arena, which extend beyond the scope of this Guidebook. Some of the complicating factors associated with solid fuels and heavy fuel oils are outlined in the following paragraphs.

It is interesting to note that all fuels combust in the gaseous state. Fuel oils must boil (vaporize) then the fuel can react with oxygen in the combustion zone. Coal must increase in temperature enough to diffuse into the vapor state before it can combust. Natural gas is immediately ready to react in the combustion zone. As a result, liquid fuels and solid fuels have much more potential for combustion zone issues resulting in unburned fuel than natural gas has. It should be noted that light fuel oil readily boils and quickly reacts in the combustion zone. All fuels must be properly introduced to the flame zone to achieve effective combustion; but, heavier fuel oils and solid fuels require much more attention in the burner and combustion zones than natural gas and light fuel oil.

An integral part of the combustion process is the heating of the fuel to an appropriate temperature that will allow the chemical reaction to take place. However, fuel temperature has much more of an impact in the burner and combustion zones. As stated previously, in order for fuel oil to burn it must increase in temperature and vaporize. The fuel oil receives heat transfer from the flame zone to increase in temperature. Heat transfer is directly proportional to the surface area exposed to the energy source. As a result, one of the functions of the burner system is to break liquid fuels into droplets that are as small as possible—the smaller the droplets the greater the overall liquid surface area. In order for the fuel delivery nozzle to break the liquid fuel into small droplets it must be heated to an appropriate temperature prior to entering the burner. In fact heavy fuel oils must be heated significantly simply to be liquid (many heavy fuel oils are solids at typical ambient temperatures).

Solid fuels must be appropriately sized to match the fuel delivery and burner systems. Most burners cannot tolerate fuels that are not within strict size limits. Most solid fuels contain liquid water, which must be evaporated before the fuel components can gain sufficient temperature to enter the combustion process. As a result, fuel conditioning and preheating are commonly determining factors in the combustion process. These issues introduce significant complication into the boiler tune-up process.

Solid fuels often receive a significant portion of their heat from preheated combustion air. In some instances preheated combustions air conveys the fuel to the burner (pulverized coal, for example). Preheated combustion air serves to heat the fuel and evaporate the water contained in the fuel.

It is interesting to note that most solid fuels contain an appreciable amount of liquid water. Most coals will contain at least $5\%_{\text{mass}}$ water and it is not uncommon for the water content to be $15\%_{\text{mass}}$ or higher. Green wood typically contains near $50\%_{\text{mass}}$ water. The water content is often variable, changing with respect to supply source, storage practices, and handling issues. The quality of the fuel can significantly influence the boiler tune-up process.

Many solid fuel boilers incorporate multiple combustion air streams into the combustion process. Primary air may convey the fuel into the burner and secondary air may be introduced into the burner arena to provide the majority of combustion air. Overfire air is most commonly supplied to the upper regions of the combustion zone to finish the combustion process and to aid in the management of emissions. All of these air flows and management factors must be managed by the boiler tune-up procedure.

The burner arrangements for solid fuels and heavy fuel oils are widely varied. Fuel is distributed to the combustion zone in very different manners. These factors complicate the combustion tuning process because not only is the air-fuel ratio a major factor but fuel particle size, composition, and distribution are also major factors. All of these factors must be addressed in the tune-up process.

Solid fuels and fuel oils contain mineral matter that becomes solid refuse from the combustion process. This material is known as ash and can be as much as $30\%_{\text{mass}}$ of the fuel supply. Ash collection and removal must be addressed in the combustion management process. Also, fuel conditioning (especially fuel particle size) directly effects the amount of unburned fuel remaining in the ash. The temperatures the ash is exposed to in the combustion zone will tend to melt the minerals resulting in large agglomerations of ash known as clinkers. As a result, combustion zone temperatures must be addressed during the tuning process.

Also, solid fuel combustion presents fuel flow measurement difficulties. Most of the solid fuel fired boilers are not equipped with fuel flow measurement. This sometimes results in the air flow control device being controlled from the steam flow rate, further complicating the control of the boiler.

These wide variations in equipment, fuel composition, and fuel characteristics make a concise treatment of the boiler tune-up activities associated with solid fuel and heavy fuel oil boilers expansive. As a result, this Guidebook has been written with natural gas and light fuel oil as the focus. These fuels represent the easiest fuels to manage and tune. The concepts and philosophies outlined in this Guidebook are directly applicable to heavy fuel oil and solid fuels even though the exact components described herein are a simplified version of the more complicated combustion controls.

2) Boiler Efficiency

When investigating steam systems the boiler is one of the primary targets for energy efficiency improvement. There are many tools used in the evaluation and management of boiler performance. One of the most useful tools is boiler efficiency. Boiler efficiency describes the fraction of fuel energy that is converted into useful steam energy. Of course, the fuel input energy that is not converted into useful steam energy represents the losses of the boiler operation. Boiler investigations generally evaluate the losses by identifying the avenues of loss, measuring the individual loss, and developing a strategy for loss reduction.

There are many avenues of efficiency loss encountered in boiler operations. Some of these avenues will be very briefly discussed to properly place the focus of this Guidebook—combustion management—into the overall context of boiler efficiency. Typically the dominant loss is associated with the energy leaving the boiler with the combustion gases. The temperature of the exhaust gases is an indication of their energy content and the resulting loss. Ensuring that the heat transfer surfaces of the boiler are clean is a major point of focus for managing the thermal energy in the exhaust gases.

Another aspect of exhaust gas energy management, and the one this Guidebook focuses on, is classified as combustion management. It should be noted that the temperature of the exhaust gases and combustion related attributes of the exhaust gases are interrelated—they combine to represent the *stack loss* of the boiler. Stack loss is typically the dominant loss for the boiler. Stack loss is dependent on the operating characteristics of the boiler, the equipment installed, and the type of fuel burned in the boiler. Stack loss generally ranges from more than 30% for a green-wood fired boiler, to 18% for a typical natural gas fired boiler, to 12% for an oil-fired boiler, to as low as 9% for a coal fired boiler. It must be pointed out that the stack loss range is wide for a given fuel and is primarily impacted by the type of thermal energy recovery equipment the boiler has and the manner in which combustion is controlled.

The primary goals of a boiler tune-up are to provide safe combustion with the minimum amount of fuel expenditure while maintaining environmental compliance. In other words, a boiler tune-up is designed to improve the combustion related efficiency aspects of boiler operation. As a result, the basic concepts of boiler efficiency need to be understood.

Boiler fuel-to-steam energy conversion efficiency can be precisely defined in many ways. In this Guidebook a simple definition will be adopted which will serve as a general vehicle to communicate the concepts of this text. The simple definition adopted here is based in the *first law of thermodynamics*, which is also known as the *principle of conservation of mass-and-energy*. This efficiency analysis evaluates the amount of fuel energy that has been converted into useful steam energy.

The measurements used to express this boiler efficiency analysis are relatively straightforward. The classic data requirements for the first-law boiler efficiency analysis are steam production, feedwater properties, steam properties, fuel consumption, and fuel properties. The classic equation defining boiler *first law of thermodynamics efficiency* (η_{first}) is provided below.

$$\eta_{first} = \frac{\dot{m}_{steam}\left(h_{steam} - h_{feedwater}\right)}{\dot{m}_{fuel} HHV_{fuel}}$$

Equation 1

The steam and feedwater properties (h_{steam}, $h_{feedwater}$) required in Equation 1 are the enthalpies of steam and feedwater, respectively. The fuel higher heating value (HHV_{fuel}) is utilized as the energy content of the fuel. The remaining quantities required for the analysis are the mass flow rates of steam ($\dot{m}_{steam}$) and fuel ($\dot{m}_{fuel}$).

This efficiency definition can also be thought of as a fuel-to-steam energy efficiency. In other words, this equation is attempting to identify how much fuel energy was transferred into the steam. Any fuel energy not transferred to the steam is considered a loss. It is good to note that boiler efficiency can be defined in other manners. This definition is adopted here because it is simple and it serves as an accurate vehicle to aid in boiler tune-up evaluations.

As a point of note, *Equation 1* has been identified in this text in reference to the fuel Higher Heating Value (*HHV)*—fuel Lower Heating Value (*LHV)* could be used as an alternate. There are three primary factors that should be considered when selecting HHV or LHV as the analysis basis. First is consistency; in other words, all analyses should be completed with a common basis. Second, it is more accurate to utilize HHV when multiple fuel types are used. Third, is the fact that fuels are typically purchased and compared based on the fuel Higher Heating Value. In the following discussions only the fuel Higher Heating Value will be utilized.

Even though *Equation 1* serves as the definition of boiler efficiency in this Guidebook, the equation as it is expressed is not the primary working tool in the tune-up investigations. It is often more beneficial in the tune-up activity to explore the various avenues through which fuel energy can be lost. As a result, a *loss-based* boiler efficiency analysis will be used extensively in this Guidebook. It is important to note this *loss-based* boiler efficiency evaluation adheres to the same definition of boiler efficiency as expressed in *Equation 1*—the differences are in the field measurements used to obtain the efficiency values. This *loss-based* efficiency is also known as *indirect efficiency*.

The indirect efficiency investigation method basically evaluates the major factors contributing to efficiency degradation and quantifies the loss associated with each. These losses combine to be the total loss for the boiler and an efficiency evaluation results. The basic equation is provided below.

$$\eta_{indirect} = 100\% - \lambda_{stack} - \lambda_{blowdown} - \lambda_{shell} - \lambda_{auxiliary} - \lambda_{misc}$$

Equation 2

The losses identified here— stack loss, blowdown loss, shell loss, auxiliary loss, and miscellaneous loss (λ_{stack}, $\lambda_{blowdown}$, λ_{shell}, $\lambda_{auxiliary}$, λ_{misc})—are typically the major losses contributing to boiler inefficiency. All of the losses are expressed in terms of a percentage of total fuel input energy (fuel Higher Heating Value basis). A benefit of this type of analysis is that a roadmap for improving boiler efficiency can be established from the magnitude of the losses. Also, the potential efficiency improvement for each focus area can be determined, which allows the economic benefit of a boiler adjustment activity to be established.

Generally, steam generation efficiency analysis focuses on individual boiler operation with investigation of all of the losses for the boiler. Often three of the losses dominate the investigation. The first is typically a minor loss and is categorized as *radiation and convection loss* or *shell loss*. The second is also a minor loss and is identified as *blowdown loss*. Even though blowdown loss is typically relatively small, reduction and recovery of this loss can many times be facilitated with simple, cost effective measures. The third focus area is associated with boiler exhaust gases and is known as the *stack loss*. The *stack loss* is subdivided into three broad categories that are interrelated: *flue gas thermal loss*, *excess air loss*, and *combustibles loss*. These three categories of loss combine to represent the boiler *stack loss*. Stack loss (thermal, excess air, and combustibles) is typically the largest component loss of boiler operation—shell loss is most often less than 1% of fuel input energy, blowdown loss is commonly in this same range, while stack loss is almost always greater than 10% of fuel input energy and at times greater than 30%. Additionally, stack loss is the target loss in a boiler tune-up activity. The focus of this Guidebook will be on the stack loss. Brief descriptions of the individual losses are provided here for clarity; however, stack loss is the parameter that is of interest in the tune-up discussions.

Some boilers operate with significant *auxiliary* or *miscellaneous losses*; such as, fuel conditioning, combustion gas movement, heat transfer surface cleaning, and environmental control equipment. These losses typically apply to coal-fired, wood-fired, and other solid fuel-fired boilers. Another significant loss associated with solid fuel-fired boilers is unburned fuel in the refuse (ash).

It should be noted that the indirect boiler efficiency analysis, like the first-law efficiency analysis, attempts to measure all of the energy flows entering and exiting the boiler. These two boiler efficiency methodologies identified here serve as the foundation for the American Society of Mechanical Engineers (ASME) boiler efficiency measurement guidebook [14].

2.1 Boiler Stack Loss

A significant aspect of boiler management is the activity of managing the loss associated with energy remaining in the combustion gases as they exit the boiler. This loss is identified as the *stack loss*. Stack loss is commonly subdivided into three broad categories that are interrelated: *flue gas thermal energy loss*, *excess air loss*, and *combustibles loss*. These three categories of loss combine to represent the boiler *stack loss*. Stack loss (thermal energy, excess air, and combustibles) is typically the largest component loss of a boiler operation, ranging from 8% to more than 35% of the fuel input energy. Many factors influence the range of stack loss. The major factors include fuel type, boiler design, heat exchange surface condition, combustion management, combustion equipment, and boiler load.

There are four primary measurements that allow the stack loss of a boiler to be determined. The four measurements are final flue gas temperature, ambient temperature, flue gas oxygen content, and flue gas combustibles concentration. These four measurements along with the composition of the fuel allow the stack loss to be determined. Again, the stack loss is the fraction of fuel input energy that remains in the exhaust gases as they leave the boiler.

Reducing the stack loss through combustion management is the primary focus of a boiler tune-up activity. Specifically a boiler tune-up focuses on the excess air loss and the combustibles loss of the boiler. However, it should be noted that the flue gas temperature influences the total stack loss and is considered in a boiler tune-up activity. The following subsections of this Guidebook discuss the investigation points associated with these boiler management areas.

2.1.1 Flue Gas Temperature Loss

As a point of note in relation to this Guidebook, impacting the flue gas temperature of the boiler is not part of the active functions of a boiler tune-up. However, flue gas temperature does significantly impact stack loss and adjusting excess air can influence final flue gas temperature. As a result, the temperature aspect of stack loss will be discussed.

Boiler stack loss is intimately dependent on the temperature of the combustion gases exiting the boiler—flue gas temperature is directly reflective of energy content. Therefore, the greater the flue gas exhaust temperature the greater the stack loss. For a typical fuel-fired boiler, flue gas temperature management focuses on maintaining the heat transfer surfaces of the boiler in a clean condition, ensuring the flue gases are passing through the boiler in an appropriate path, and installing the appropriate amount of heat transfer surface area in the boiler. For solid-fuel fired boilers and heavy fuel oil fired boilers, a common method of maintaining clean heat transfer surfaces is by utilizing soot-blowing equipment. Soot-blowers commonly utilize jets of steam or compressed air to dislodge particulate matter from heat transfer surfaces while the boiler is in operation. Natural gas and light fuel oil fired boilers rarely develop fire-side fouling requiring soot-blowing.

Since boiler stack loss is dependent on the temperature of the gases exiting the unit, reducing exhaust gas temperature is the primary method to capture energy that would otherwise be lost. Heat transfer area is the primary avenue allowing management and recovery of flue gas thermal energy. Feedwater economizers and combustion air heaters serve as the most common thermal energy recovery components increasing the boiler heat transfer surface area.

It should be noted that the final flue gas temperature is a function of boiler load. Final flue gas temperature will increase as the boiler steam production rate (fuel input) increases. This is primarily a result of the fact that a boiler is a heat exchanger with a fixed amount of heat transfer area. As the boiler load increases the mass flow of gases passing through the boiler increases; but, the heat transfer area remains constant. More heat is transferred but the final exhaust gas temperature tends to increase as well.

Often final flue gas temperature is also impacted by the amount of excess air passing through the boiler. Most commonly, for a constant boiler load, as the amount of excess air increases the final flue gas temperature increases. This is a result of several factors all associated with heat transfer in the boiler. First, consider that as the amount of excess air increases in the combustion zone the flame temperature decreases. Heat transfer in the combustion zone has a major radiation heat transfer component. Since radiation heat transfer is proportional to the difference of the flame temperature raised to the fourth power and the wall temperature raised to the fourth power (both on the absolute scale). Increasing excess air in the combustion zone decreases the flame temperature. Radiation heat transfer is proportional to the fourth power of the absolute flame temperature; therefore, the amount of radiation heat transfer is significantly reduced in the combustion zone.

Second, the amount of combustion gas increases as excess air is increased. This increased mass flow will pass across the same amount of heat transfer area in areas in the boiler where convection heat transfer is dominant. This gas flow will be more energetic because of the reduction in radiation heat transfer and because the mass flow rate of air will be larger. These factors often result in final flue gas temperature increasing as excess air increases. These factors are important when it is desirable to identify the performance impacts of a tuning.

2.1.2 Flue Gas Combustion Loss

In order for complete combustion (fuel energy release) of a fuel to take place each fuel molecule must encounter a sufficient amount of oxygen to allow the reaction to proceed to completion. If the reaction is not allowed to proceed to completion then a portion of the fuel resource will be exhausted—unused—from the boiler. In the majority of combustion systems if a sufficient amount of extra combustion air is passed through the combustion zone the result will be an almost complete combustion of the fuel resource. Because the oxygen (air) resource is relatively low cost—essentially free when compared to the fuel resource—an extra amount of oxygen (air) is added to the combustion zone to ensure the fuel resource is consumed.

It should be pointed out that unburned fuel exhausted from the boiler is not only an efficiency detriment but it also represents an environmental, health, and safety hazard. The unburned fuel can ignite in a location where a flame cannot be tolerated resulting in an explosion or other problem. Also, fuels and partially combusted fuels are typically toxic in nature. As a result of these losses and issues, there must be a sufficient amount of excess air passing through the combustion zone to achieve efficient and safe boiler operation.

Even though excess air is required in the combustion zone to manage the amount of unburned fuel, the amount of excess air must be managed to reduce system losses. Excess air is required in the combustion zone for effective combustion of the fuel resource. In a typical boiler, excess air provided to the combustion zone enters the boiler at ambient temperature and exits the boiler at a significantly elevated temperature—flue gas exhaust temperature. This elevation in temperature is provided by fuel energy, which represents a loss to the system. The temperature rise of the excess air passing through the boiler is often several hundred degrees Fahrenheit. Furthermore, the source of the extra oxygen for the combustion zone is ambient air, which contains 3.76 molecules of nitrogen for every molecule of oxygen that passes through the boiler. This nitrogen does nothing to improve the operations of the boiler; it only serves to receive fuel energy and carry it away from the boiler. Nitrogen represents one of the largest mass flow rates of materials passing through the boiler, absorbing fuel energy. As a result, excess air must be minimized to properly manage the fuel resource. *The management of flue gas oxygen content requires the flue gas oxygen concentration to be managed between an upper and lower limit. The lower limit is established to ensure the majority of the fuel resource is combusted and the upper limit is established to ensure the thermal energy loss is minimized.* It should also be noted that the formation of nitrogen oxides is also dependent on the conditions in the combustion zone. In other words, nitrogen oxides must also be considered in the combustion management process.

The appropriate range within which to manage excess oxygen depends on the fuel type and the method of monitoring and controlling flue gas oxygen content. The following table, *Table 1 – Typical Flue Gas Oxygen Content Control Parameters* provides some general information of the typical control limits for steam boilers. The data represented in this table indicates the *expected* operating range for boilers. There are many factors that may impede an individual boiler from operating within the range specified. One dominant factor is the burner load. Burners operating at the low-range of capacity will typically require more excess air than when operating at the high-range of capacity.

The numerical values in the table represent the amount of oxygen (O_2) in the flue gas as it exits the combustion zone. This is the actual field measurement for most boilers and it is the common control parameter. The amount of oxygen in the exhaust gases can also be expressed as *excess air*. Excess air is the amount of air introduced to the combustion zone in comparison to the theoretical—stoichiometric amount—required for complete combustion with no excess air. The oxygen concentrations noted in the table are “full gas sample” measurements (the typical alternative measurement is “dry basis” measurement). *Full gas sample* is also known as *wet basis*. This terminology arises from the fact that the boiler exhaust gas is a combination of several gases. The exhaust gases from the combustion of a hydrocarbon fuel in air contain nitrogen, carbon dioxide, water-vapor, and several additional chemicals. The measurement distinction of *dry* versus *wet* is based in the manner in which the water-vapor in the sample is managed. A wet based oxygen concentration identifies the amount of oxygen with respect to all of the other flue gas constituents. A dry based oxygen concentration measures the oxygen content of the flue gas sample after the water-vapor has been condensed and removed from the sample. This measurement distinction is important for many reasons and it is critical to note that different instruments provide measurements with one or the other of these bases. The difference between full gas sample and “dry basis” measurements will be discussed in further detail in the *Tools* section of this Guide—the idea is simply introduced here.

Typical Flue Gas Oxygen Content Control Parameters				
Fuel	**Automatic Control Flue Gas O_2 Content**		**Positioning Control Flue Gas O_2 Content**	
	Minimum [% full gas sample]	**Maximum [% full gas sample]**	**Minimum [% full gas sample]**	**Maximum [% full gas sample]**
Natural Gas	1.5	3.0	3.0	7.0
Numb. 2 Fuel Oil	2.0	3.0	3.0	7.0
Numb. 6 Fuel Oil	2.5	3.5	3.5	8.0
Pulverized Coal	2.5	4.0	4.0	7.0
Stoker Coal	3.5	5.0	5.0	8.0

Table 1 – Typical Flue Gas Oxygen Content Control Parameters

The two main designations in *Table 1 – Typical Flue Gas Oxygen Content Control Parameters* are *automatic control* and *positioning control*. *Positioning control* is generally accomplished as part of a boiler control system that is not equipped with continuous flue gas oxygen measurement. Typically, this type of control is based on a pressure controller observing steam pressure, which controls fuel flow into the boiler. As the steam pressure decreases, the controller will increase fuel flow to increase boiler steam output. Combustion air flow will be increased in a preset manner in response to the fuel flow setting. This type of control does not adjust combustion air based on flue gas oxygen content. The position of the fuel control device dictates the position of the air flow control device. Periodically the relationship—*position*—between the combustion air setting and the fuel control setting is verified and adjusted through flue gas oxygen content evaluation (and combustibles evaluation).

The more efficient control is listed in *Table 1 – Typical Flue Gas Oxygen Content Control Parameters* as *automatic control*. *Automatic control* (or *continuous automatic control*) is also based on controlling steam pressure by varying fuel flow into the boiler. However, flue gas oxygen content is measured and controlled as well. Oxygen content is continually monitored and combustion air flow is trimmed to maintain required oxygen limits.

Both forms of control can be accomplished in many different arrangements. However, the fundamental principles are as represented here. Continuous automatic control provides closer excess air control than positioning control. If combustibles monitoring and control is added to continuous automatic control the most efficient combustion management can be achieved. Of course, continuous automatic combustion control requires more equipment and economic investment than positioning control—but efficiency improvement generally results.

It should also be noted that any type of combustion control will probably result in a range of flue gas oxygen content across the load range of the boiler. Most boilers require less excess oxygen at higher loads than at lower loads primarily because of the improved mixing and combustion parameters at higher loads.

2.1.3 Combustibles Loss

Obviously any amount of un-reacted fuel in the exhaust gases represents a loss to the boiler. Under most situations, when the amount of excess air is reduced below a minimum threshold in the combustion zone the concentration of unburned fuel in the exhaust gases will increase. Often, the increase will be dramatic once a minimum point is passed. This dramatic increase in combustibles concentration marks the minimum range of excess air that the burner can effectively combust the fuel. The amount of combustible material in the exhaust gas varies significantly with respect to fuel type. Natural gas will generally have a much lower baseline combustibles concentration than heavy fuel oil combustion. Typically, solid fuels will operate with the highest combustibles concentration baselines. In other words, solid fuels generally require a higher amount of excess air (oxygen) for proper combustion.

It must be pointed out that many factors influence the amount of combustibles in the flue gas. Incomplete combustion occurs when conditions present in the combustion zone do not allow the fuel to fully react. Many factors affect this activity with the main parameters being:

- Reaction time
- Reaction temperature
- Degree of mixing

In other words, for the combustion reaction to proceed to completion fuel and oxygen must have enough time to react, they must be within the proper temperature range, and they must be appropriately mixed. If any component is missing or diminished the reaction will not proceed to completion and combustibles will exit the combustion zone. Babcock and Wilcox describe this as "the three T's of combustion; ***T***ime, ***T***emperature and ***T***urbulence" [7, 10-1].

For most boilers, a combustibles concentration of less than 200 parts per million (ppm) is accepted as "proper operation". However, a baseline concentration should be developed for each boiler because a typical natural gas fired boiler often operates with combustibles in the 10 ppm range as a baseline. A stoker coal-fired boiler may operate with a baseline combustibles concentration of 300 ppm. Deviation from the baseline for a given boiler would indicate a potential combustion problem. An increase in flue gas combustibles generally indicates poor burner performance, deficiency in combustion air, or excessive combustion air. Generally when the combustibles concentration is less than 100 ppm the energy loss associated with combustibles is essentially negligible. When the combustibles concentrations are much greater the loss can be significant and dangerous conditions can result. When nitrogen oxides are controlled the combustibles concentration can be elevated significantly above these reference values indicated here.

It should be reinforced that the presence of significant combustibles in the flue gas can also be indicative of equipment issues. The combustion equipment can experience failures that can result in poor combustion even if significant amounts of excess air are passed through the combustion zone. This point highlights the importance of establishing a baseline combustibles concentration for all boilers.

As an example, if the combustibles concentration of a natural gas fired boiler is nominally 100 ppm then the fuel energy loss is negligible. If the combustibles concentration is on the order of 1,000 ppm the loss will be approximately 0.6% of fuel input energy—the values stated here are only representative because the loss fraction is dependent on excess air amount as well as fuel composition.

2.1.4 Boiler Stack Loss Summary

As mentioned previously determination of the stack loss for combustion operations requires four primary measurements and the use of a stack loss model. Final flue gas temperature is a required measurement in the evaluation along with ambient temperature. Ambient temperature is the temperature of the combustion air entering the boiler operations (entering the forced-draft fan in many cases). The actual measurement of importance is the temperature difference between the flue gas temperature and the ambient temperature. This temperature difference is known as the *net stack temperature*. Net stack temperature is the primary measurement because the inlet air temperature will have an impact on the final flue gas temperature. In other words, a boiler operating with very low inlet air temperature will experience a lower final flue gas temperature than the same boiler operating under similar load with a much higher inlet air temperature.

Flue gas oxygen content is the next measurement required to evaluate the stack loss. Flue gas oxygen content is the field measurement indicating the combustion process has completed and oxygen remains in the flue gas. The location of the flue gas oxygen content measurement must be given careful consideration. This issue is discussed in a following section of this Guidebook (*Measurement Locations*).

Additionally, it is important to note that flue gas oxygen content is commonly measured by two methods. The first method yields a "full gas sample" (also known as "wet gas sample") flue gas oxygen concentration. The second method yields a "dry gas sample". In general in-situ flue gas oxygen sensors measure full gas sample oxygen concentration. Alternately, most portable combustion analyzers measure dry gas sample. Additional information is provided on this subject in the *Tools* section of this Guidebook.

The final field measurement required to determine the stack loss is the flue gas combustibles concentration. Combustibles concentration quantifies the amount of fuel that has not reacted in the combustion process. Generally, unburned fuel has a negligible impact on stack loss if it is less than 100 ppm concentration.

As an example, consider a boiler burning natural gas. The final flue gas temperature has been measured to be 400°F and the ambient temperature has been measured as 70°F. The net stack temperature is 330°F (400°F - 70°F = 330°F). Flue gas oxygen content was measured with a portable combustion analyzer as 8.0% dry gas sample. The flue gas combustibles concentration measured to be ~0 ppm (negligibly small). This information can be used along with a stack loss model for natural gas to determine the stack loss as shown below. In this example the stack loss was determined as 19.7%. If the other boiler losses (blowdown loss, shell loss, miscellaneous loss) were evaluated (or estimated) to be negligible, then the boiler efficiency would be 80.3% (100% - 19.7% = 80.3%).

Stack Loss Table for			**Typical Natural Gas**											
Flue Gas Oxygen Content Wet Basis	**Flue Gas Oxygen Content Dry Basis**	**Comb Con**	**Stack Loss [% of fuel Higher Heating Value input]** **Net Stack Temperature [Δ°F]** **{Difference between flue gas exhaust temperature and ambient temperature}**											
[%]	**[%]**	**[ppm]**	**180**	**205**	**230**	**255**	**280**	**305**	**330**	**355**	**380**	**405**	**430**	**455**
1.0	1.2	0	13.6	14.1	14.7	15.2	15.8	16.3	16.9	17.4	18.0	18.5	19.1	19.6
2.0	2.4	0	13.8	14.3	14.9	15.5	16.1	16.6	17.2	17.8	18.4	18.9	19.5	20.1
3.0	3.6	0	14.0	14.6	15.2	15.8	16.4	17.0	17.6	18.2	18.8	19.4	20.0	20.6
4.0	4.7	0	14.2	14.8	15.5	16.1	16.7	17.4	18.0	18.7	19.3	20.0	20.6	21.2
5.0	5.8	0	14.5	15.1	15.8	16.5	17.2	17.8	18.5	19.2	19.9	20.5	21.2	21.9
6.0	6.9	0	14.8	15.5	16.2	16.9	17.6	18.3	19.1	19.8	20.5	21.2	22.0	22.7
7.0	8.0	0	15.1	15.9	16.6	17.4	18.1	18.9	19.7	20.5	21.2	22.0	22.8	23.6
8.0	9.1	0	15.5	16.3	17.1	17.9	18.8	19.6	20.4	21.2	22.1	22.9	23.7	24.6
9.0	10.1	0	16.0	16.8	17.7	18.6	19.5	20.4	21.2	22.1	23.0	23.9	24.8	25.7
10.0	11.1	0	16.5	17.4	18.4	19.4	20.3	21.3	22.2	23.2	24.2	25.2	26.1	27.1
Actual Exhaust T [°F]			**250**	**275**	**300**	**325**	**350**	**375**	**400**	**425**	**450**	**475**	**500**	**525**
Ambient T [°F]			**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**

Table 2 – Stack Loss Table for Natural Gas

2.2 Blowdown Loss

This subsection is included with regard to completeness and in an effort to identify the magnitude of the blowdown loss. Blowdown is typically a minor boiler loss and it is not associated with the stack loss. Blowdown is essential for continued operation of any boiler; and, it represents a loss to the steam system. It is often very difficult to measure the blowdown flow rate with a conventional flow meter. Blowdown mass fraction (blowdown rate) is typically determined by completing a mass balance on an impurity that is in the feedwater and that is essentially insoluble in steam. The mass balance targeting this component (impurity) is represented in the following equation.

$$\underbrace{\frac{dm_{cv}}{dt}}_{SSSF=0} = \sum_{\text{chemical component}} \dot{m}_{inlet} - \sum_{\text{chemical component}} \dot{m}_{exit}$$

Equation 3

Where the first term ($\frac{dm_{cv}}{dt}$) is the rate of accumulation of mass within the boiler. In order for the analysis to be carried out the boiler must be at steady-state, steady-flow operation (SSSF) with no changes in any of the properties within the boiler. In other words, mass is not accumulating in the boiler—any mass entering the boiler exits the boiler. As a result, this accumulation term is zero. The equation simplifies to the sum of all mass flows entering the boiler equal to the sum of all the mass flows exiting the boiler.

The target chemical component is essentially insoluble in steam. As a result, the chemical enters with the feedwater and exits with the blowdown only. If continuous blowdown is employed and the individual chemical concentration is not changing within the boiler then the mass balance equation can be simplified. The simplification incorporates the chemical concentration measurement in the feedwater stream, $C_{feedwater}$, and the chemical concentration in the blowdown stream, $C_{blowdown}$.

$$C_{feedwater}\, \dot{m}_{feedwater} = C_{blowdown}\, \dot{m}_{blowdown}$$

$$Blowdown = \beta = \frac{\dot{m}_{blowdown}}{\dot{m}_{feedwater}} = \frac{C_{feedwater}}{C_{blowdown}}$$

Equation 4

Blowdown is typically expressed as a percentage of total feedwater flow. A less accurate estimate of blowdown fraction can be attained by determining the ratio of feedwater conductivity to blowdown conductivity. Any analysis must consider the accuracy and precision of the chemical concentration measurements. It is often very difficult to determine the blowdown rate on boilers receiving high quality feedwater because the instruments cannot accurately measure the relatively low concentration of chemicals in the water.

If the blowdown amount is known, the loss associated with blowdown can be estimated. The *classic boiler blowdown loss* equation follows.

$$\lambda_{blowdown} = \frac{Energy\ added\ to\ the\ blowdown\ stream}{Total\ energy\ added\ to\ the\ boiler\ with\ fuel}$$

$$\lambda_{blowdown} = \frac{\dot{m}_{blowdown}\left(h_{blowdown} - h_{feedwater}\right)}{\dot{m}_{fuel}HHV}(100)$$

Equation 5

The blowdown and feedwater properties (h_{steam}, $h_{feedwater}$) required in *Equation 5* are the enthalpies of saturated liquid blowdown and feedwater, respectively. The fuel higher heating value (HHV_{fuel}) is utilized as the energy content of the fuel. The remaining quantities required for the analysis are the mass flow rates of steam ($\dot{m}_{blowdown}$) and fuel ($\dot{m}_{fuel}$). *Equation 5* will provide the loss associated with blowdown as a percent of total energy input with the fuel.

The loss associated with boiler blowdown is generally a relatively minor energy stream. This results from two primary factors. First, the blowdown amount is typically a relatively small fraction of feedwater flow to the boiler. Generally, blowdown ranges from 0.5% of feedwater flow to 10.0% of feedwater flow—this is a broad range that is dependent on many factors. But the energy loss is much less than this range because of the second factor. The second factor is the fact that the blowdown that is discharged from the boiler is saturated liquid, which has much lower energy content than steam. Therefore, a $5.0\%_{mass}$ blowdown rate can translate into a 1.5% energy loss. If blowdown thermal energy recovery components are in-place the energy loss can be virtually eliminated.

Blowdown management and energy recovery can be excellent areas to focus attention for system performance improvement. However, blowdown management is not a focal point of this Guidebook.

2.3 Boiler Shell Loss (Radiation and Convection Loss)

For reasons similar to those of the *Blowdown Loss* section, this subsection is included with regard to completeness, and in an effort to identify the magnitude of the shell loss. The outer surface of a boiler is exposed to the surroundings and provides an avenue for fuel energy to be released to the environment. One of the functions of the boiler shell is to reduce the amount of heat transferred to the ambient from the internal areas of the boiler. The boiler shell insulates and isolates the high-temperature fluids inside the boiler from the ambient surroundings. Heat transfer, primarily in the forms of radiation and convection, occurs from the outer surface of all boilers. Radiation and convection losses from the boiler shell are a function of the physical size of the boiler, the boiler type, and the condition of the insulation and refractory of the boiler.

The type of boiler influences the magnitude of the shell loss. Most *fire-tube* type boilers inherently experience minimal shell loss. This is primarily from the design characteristic that the high-temperature combustion gases are surrounded by the water that is desired to be heated. Most of the outer boiler shell is then required to insulate the relatively medium-temperature boiling water from the low-temperature ambient. Furthermore, typical *fire-tube* boilers are manufactured with a relatively small amount of outer surface area. These factors result in *fire-tube* boilers experiencing relatively minor shell losses—typically less than 0.5% of fuel input energy for moderate boiler load.

Heavy industry *water-tube* boilers generally exhibit greater shell loss than *fire-tube* boilers because of the greater relative outer surface area (shell) of the boiler and an increased number of avenues for high-temperature gases to be exposed directly to the shell of the boiler. However, these issues are generally not overpowering and the shell loss is typically minimal.

It is generally time consuming to measure the shell loss of a boiler. Therefore, estimating techniques have been developed to determine the general range of shell loss for typical boilers. The American Society of Mechanical Engineers (ASME) has developed a calculation technique that can be used to estimate the shell loss associated with any boiler [14]. The method uses the measured outer surface area of the boiler, the measured surface temperatures of the boiler, the ambient temperature surrounding the boiler, and an estimate of the velocity of the ambient air moving at the surface of the boiler. The methodology is defined in the ASME Performance Test Code 4 (PTC-4). It must be stressed that in general shell loss evaluations are estimating techniques and should not be considered rigorous evaluations.

Shell loss is commonly a minor loss with minimal opportunity for significant energy improvement. Shell loss management is not a focal point of this Guidebook.

3) Combustion Control

There are many types of boiler combustion control; however, boiler combustion control can be divided into two broad categories—*positioning combustion control* and *automatic combustion control*. *Automatic combustion control* is identified as any combustion system that actively measures and controls flue gas oxygen content. *Positioning combustion control* is a combustion control system that manages the combustion airflow based on the position of the fuel control device. The combustion air flow control device will have a *position* that is directly related to a specific *position* of the fuel flow control device.

A boiler tune-up activity is focused on ensuring the existing combustion control system achieves the optimum amount of excess air throughout the operating range of the boiler. The optimum amount of excess air will result in the exhaust gases from the combustion process exhibiting minimal unburned fuel and minimal excess oxygen. The combustion control method will significantly influence the minimum airflow for a particular boiler load. The type of fuel burned in the boiler will significantly influence the control parameters for the combustion process. Additionally, environmental controls can have an influence on the minimum airflow for a particular boiler load.

This section of the boiler tune-up Guidebook is intended to describe the typical combustion control methods that become the target for the tune-up effort. These discussions are focused on the combustion management aspects of boiler operations; but it should be noted that the temperature of the exhaust gases and combustion related attributes of the exhaust gases are interrelated—they combine to represent the stack loss of the boiler. Again, the stack loss is typically the dominant loss for the boiler. Stack loss is dependent on the operating characteristics of the boiler, the equipment installed, and the type of fuel burned in the boiler. Stack loss generally ranges from as much as 30% for a green-wood fired boiler, to 18% for a typical natural gas fired boiler, to 12% for an oil-fired boiler, to as low as 9% for a coal fired boiler. It must be pointed out that the stack loss range is wide for a given fuel and is primarily dependent on the amount of thermal energy recovery and the combustion control.

3.1 Principles of Combustion

In order to attain a clear understanding of the combustion control methods we will examine the combustion of a simple fuel, methane (CH_4). The chemical equation of the reaction of methane with oxygen is presented below (*Equation 6*). In a perfect world methane will react with oxygen to release energy and form carbon dioxide and water. In this perfect arrangement, each molecule of fuel would find the exact amount of oxygen in order to cause complete combustion. In the case of methane one molecule of methane must find two molecules of oxygen to produce a complete reaction.

$$CH_4 + 2O_2 \underbrace{\rightarrow}_{Energy\ \mathrm{Re}lease} CO_2 + 2H_2O$$

Equation 6

In the real world, the combustion process does not proceed in a perfect manner. A fuel molecule may encounter less oxygen than is required for complete combustion. The result will be partial combustion—the exhaust gases will then contain some un-reacted fuel and some partially-reacted fuel. Generally, these unburned fuel components are in the form of carbon monoxide (CO), hydrogen (H_2), and other fuel components that may include the fully un-reacted fuel source, which is methane (CH_4) in this case.

When unburned fuel is found as part of the combustion products, then a portion of the fuel energy that was purchased is being discharged from the system unused (thrown away). It is also important to note that unburned fuel can accumulate to the point that a safety hazard can result. Unburned fuel can burn in a part of the boiler not designed for combustion or the materials can even explode under certain conditions. These chemicals are also typically toxic in nature presenting health as well as other environmental hazards.

$$CH_4 + 2O_2 \underbrace{\rightarrow}_{Energy\ \mathrm{Re}lease} \alpha\, CO_2 + \beta\, H_2O + \gamma\, CO + \delta\, H_2 + \varepsilon\, CH_4 + \zeta\, O_2$$

Equation 7

Unburned fuel presents negative safety, health, environmental, and economic impacts to the boiler operations. As a result it is imperative to manage the combustion process to maintain these components to minimum levels. Fortunately, the complex interrelations of the combustion process can be managed with two fairly simple principles.

The *first principle of combustion management* is based in the fact that un-reacted fuel components are undesirable in the exhaust gases of the boiler but the presence of un-reacted oxygen presents minimal (if any) safety, health, and environmental concerns. Furthermore, as long as the burner is appropriately mixing the oxygen and fuel then the presence of extra oxygen in the combustion zone essentially ensures all of the fuel will completely react. Oxygen supplied to a boiler is not without cost; but, generally the fan energy required to move ambient air into the combustion zone is minimal when compared to the cost of fuel. *Combustion Management Principle Number One*, stated simply is; provide more oxygen than you theoretically need to ensure that all the fuel completely reacts.

As a result, when *combustion management principle one* is applied to the example chemical reaction, rather than two molecules of oxygen being supplied for every one molecule of methane, each molecule of methane may be provided four or five molecules of oxygen. This will ensure all of the fuel is burned. However, the extra oxygen added to the combustion zone enters at ambient temperature and exits the boiler at flue gas temperature. The flue gas temperature of a typical boiler could be in the 300°F to 500°F range. For example, the extra oxygen could have entered the boiler at 70°F and exited at 400°F. The extra oxygen gained this temperature by receiving fuel energy; in other words, fuel was purchased to heat this extra oxygen. Additionally, ambient air contains almost four molecules of nitrogen (3.76 for typical atmospheric air) for every one molecule of oxygen. As a result, every amount of excess air brings with it a huge amount of nitrogen. This nitrogen enters at ambient temperature and receives fuel energy to exit the boiler at flue gas temperature.

$$CH_4 + 2O_2 + 2(3.76N_2) \underbrace{\rightarrow}_{\substack{Energy \\ \mathrm{Re}lease}} \alpha\, CO_2 + \beta\, H_2O + \gamma\, CO + \delta\, H_2 + \varepsilon\, CH_4 + \zeta\, O_2 + 2(3.76N_2)$$

Equation 8

This brings us to *Combustion Management Principle Number Two*—do not supply too much oxygen to the boiler. In other words, combustion management requires that extra oxygen be provided to the combustion zone to ensure all the fuel is reacted; but, the amount of extra oxygen must be minimized to reduce energy loss.

The critical measurements required to manage the combustion loss are the flue gas oxygen content and the flue gas combustibles concentration. The flue gas oxygen content is measured to allow the combustion air flow to be controlled to meet a set point. Combustibles concentrations are measured to identify the minimum practical oxygen concentration.

It should be noted that combustibles concentrations can be elevated even though excess oxygen is provided to the combustion zone. This situation is typically indicative of a burner failure. A primary function of a burner is to mix the air and fuel thoroughly to ensure complete combustion. If a burner component has failed or is improperly adjusted the mixing process can be ineffective. This can result in unburned fuel and excess oxygen.

Combustibles concentration values vary based on fuel type, operating conditions, and burner conditions. A typical natural gas fired boiler will operate with combustibles concentrations less than 50 ppm while a coal-fired boiler may operate with combustibles concentrations greater than 200 ppm. Generally, combustibles concentrations less than 100 ppm are considered negligible in terms of efficiency impact. Baseline combustibles concentrations should be established for each boiler over the operating range of the equipment.

3.2 Combustion Control Strategies

The principles and measurements used in combustion management that have been outlined above indicate that combustion control should incorporate flue gas oxygen measurement, combustibles measurement, and active control of combustion airflow. However, many boilers do not incorporate these factors in the control process.

Common boiler control strategies are based primarily on steam pressure control. As the process steam demand increases the steam pressure at the boiler decreases. The boiler steam production controller will measure the difference between the pressure set point and the actual measurement and will increase fuel flow to the boiler accordingly to restore the pressure to set point. In the case of a natural gas fired boiler the controller will proportionally open the fuel control valve. As the fuel flow is increased the combustion air flow must also increase to maintain safe and efficient combustion. A very common and very simple method of accomplishing the control of combustion air flow is to mechanically link the air flow control device to the fuel flow control device. This is commonly called *positioning control* because the air flow control device will have a position that is based solely on the position of the fuel flow control device. Positioning control is represented in the following schematic.

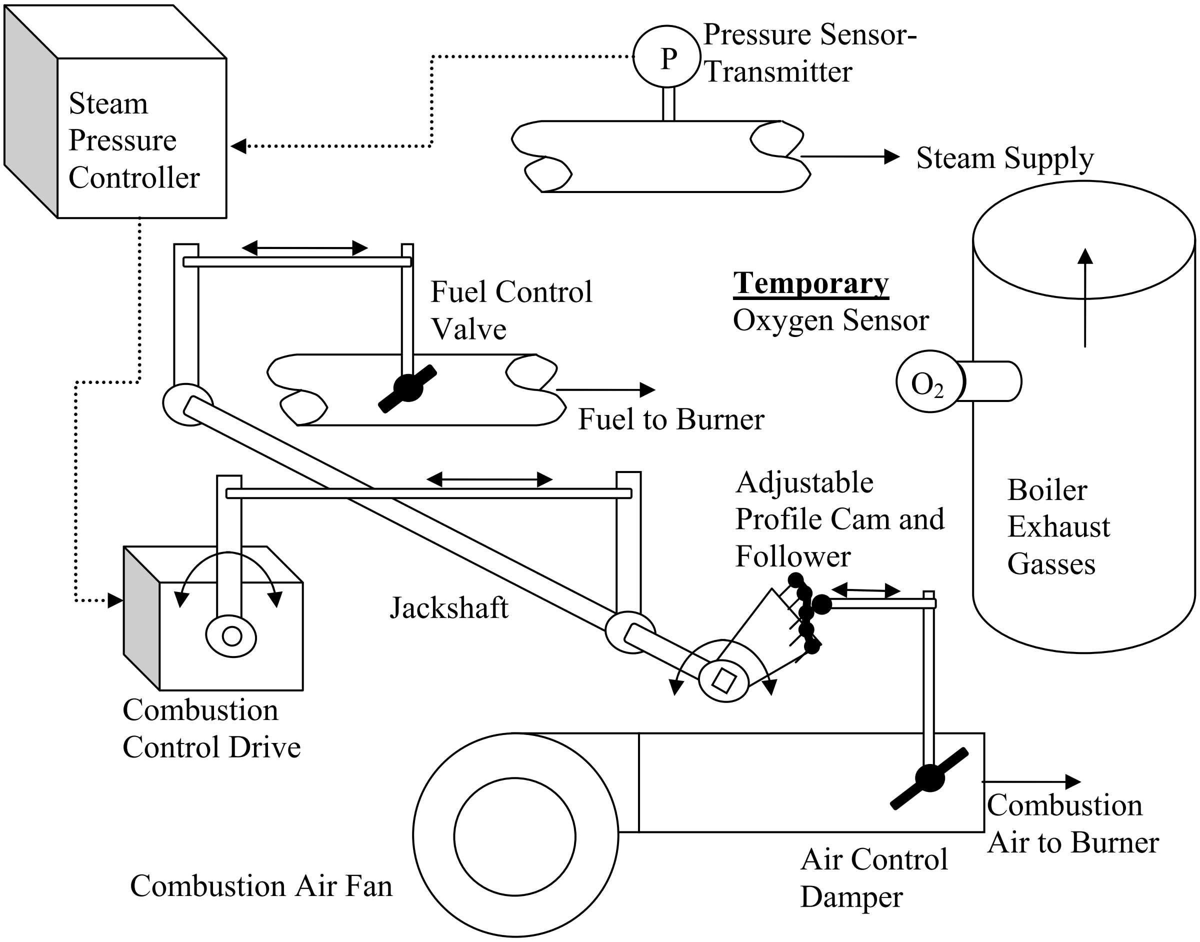

Figure 1 – Simple Positioning Control Schematic

It should be noted that positioning control does not incorporate continuous oxygen or combustibles measurement. Oxygen and combustibles measurements are taken periodically to determine if the position relationships between the fuel controller and the air controller remains appropriate—typical operation does not incorporate oxygen or combustibles measurement.

Tuning the boiler is the act of reestablishing the position relationship between the air and fuel. This tuning activity is completed by operating the boiler at a stable load, 100% of design fuel input flow for example. At this point, the position of the air flow controller is adjusted until an appropriate flue gas oxygen content is attained. Combustibles concentrations are also measured to ensure proper burner operation.

The oxygen content must not be set too low because changes in ambient conditions must be considered. Ambient temperature is a concern because the combustion air fan is basically a constant volume flow device (for a given controller set point). If the position relationship is established for a relatively cool inlet air temperature, then the mass flow of air into the combustion zone could be dangerously low as the ambient temperature increases. As a result, safe positioning control can only attain moderate efficiency. The position relationship exercise is repeated over the operating range of the boiler (95% load, 90% load, down to minimum load).

Figure 1 – Simple Positioning Control Schematic represents simple positioning control with mechanical linkages. Mechanical linkages have been represented to identify the functionality of the control system. There are positioning control units that utilize electronic linkage between the air and fuel. These systems eliminate the possibility of the alignment of many of the linkage components changing inadvertently. However, from the standpoint of this Guidebook the principles of operation are the same as outlined here.

Additionally, *Figure 1 – Simple Positioning Control Schematic* represents the variable position component on the air flow control device. Many positioning control systems (in fact, most) incorporate the variable position component on the fuel flow control device. The tuning philosophy remains the same. The primary differences are associated with establishing high-fire and low-fire conditions. *Figure 2 – Simple Positioning Control Schematic with Adjustable Fuel Controller* represents the fuel control device with the variable position component.

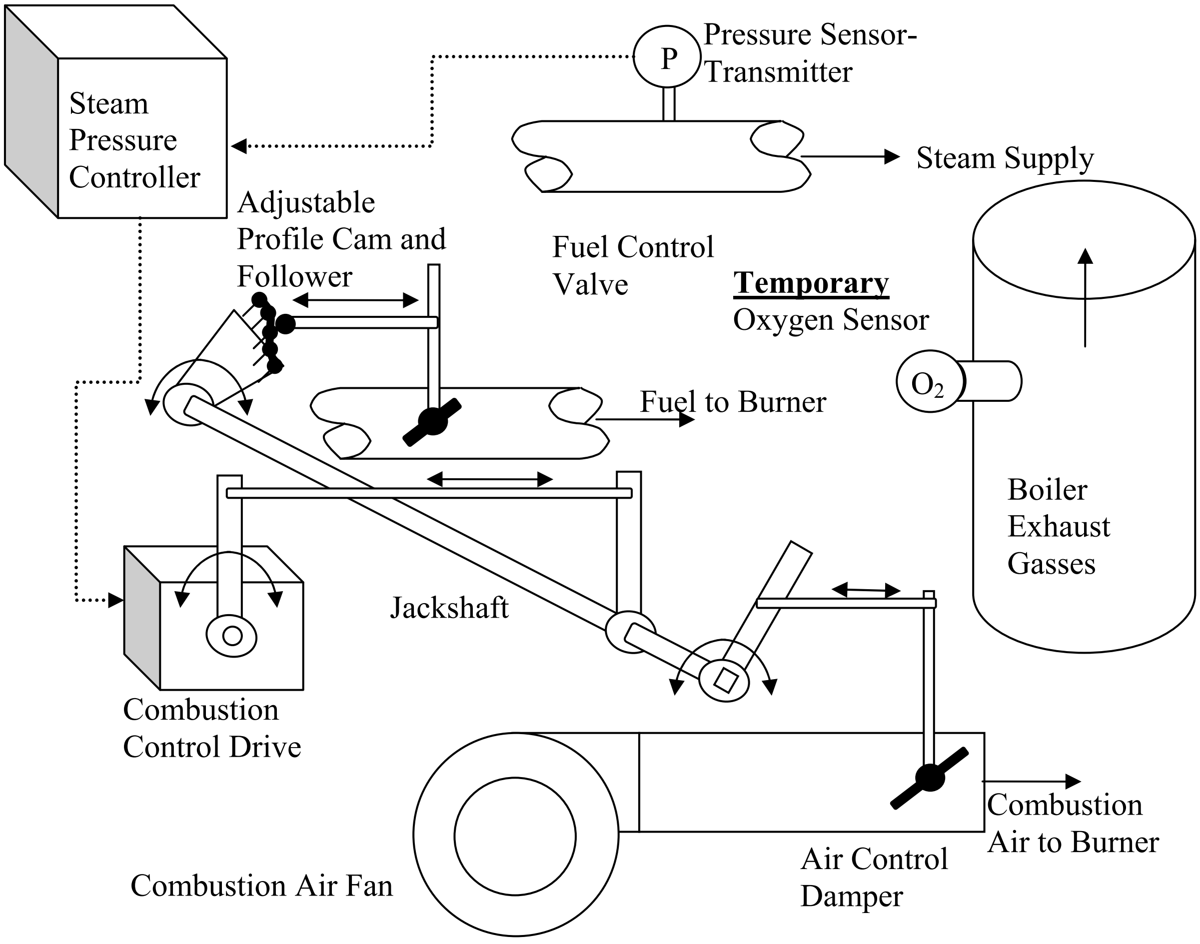

Figure 2 – Simple Positioning Control Schematic with Adjustable Fuel Controller

These schematics represent the combustion air flow control device as a fan outlet damper (fan outlet throttling control). The discussion points are equally applicable to fan Inlet Guide Vane (IGV) control and variable speed control.

Combustion control can be improved through the use of an *automatic oxygen trim system (continuous oxygen control)*. This type of system (shown as *Figure 3 – Continuous Combustion Control Schematic*) continuously measures flue gas oxygen content and adjusts the combustion air flow to maintain a set point. This type of control can be more precise and efficient than positioning control. Combustibles measurement and control can be added to allow the oxygen set point to be minimized.

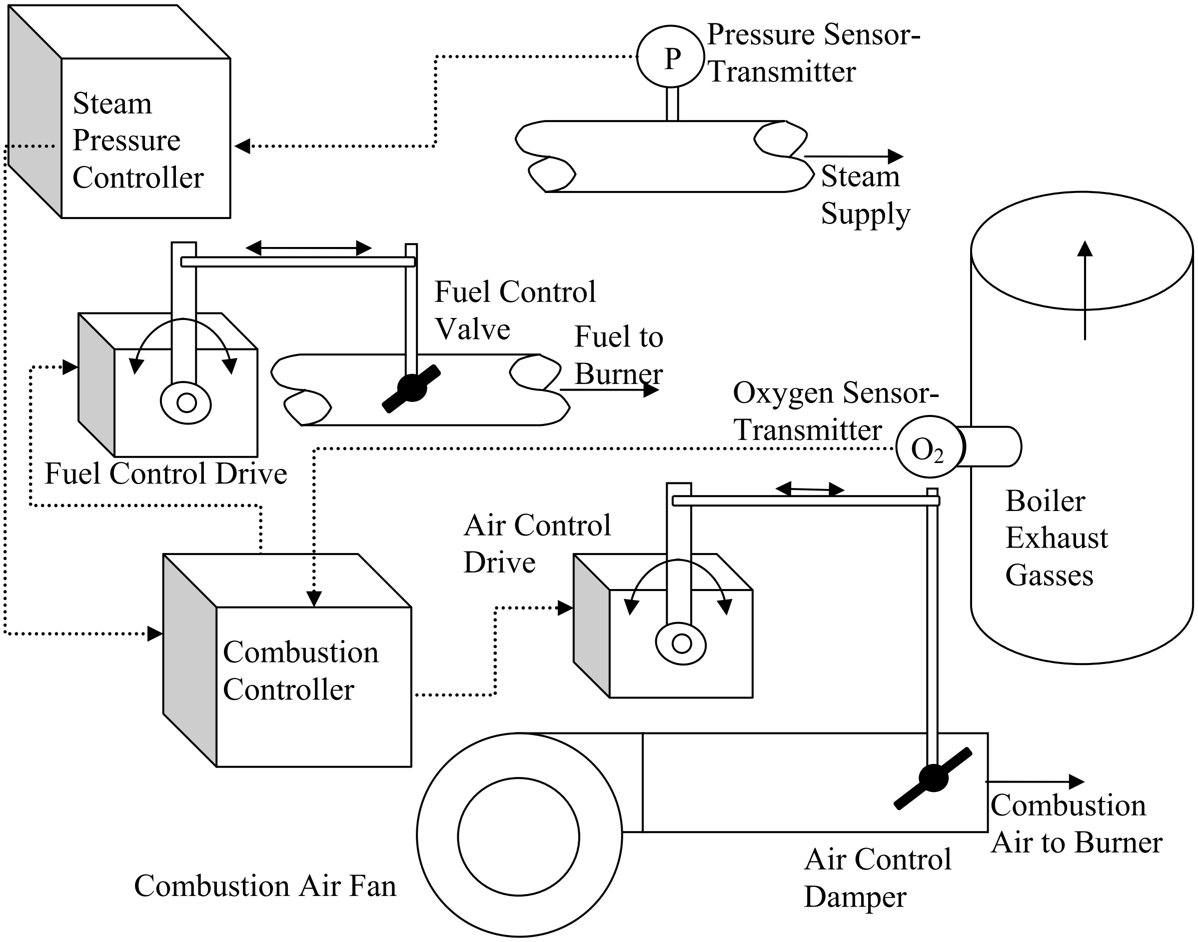

Figure 3 – Continuous Combustion Control Schematic

Often automatic oxygen trim control is applied directly to positioning control. In a jackshaft type of arrangement the principal change is to add a variable adjustment link to the airflow control mechanism. This variable link is adjusted based on the flue gas oxygen content. The jackshaft arrangement is setup to manage the general fuel and air flows over the operating range of the burner, then the variable link is adjusted to maintain the oxygen content to a set point. The trim adjustment can be thought of as a "slow" control link, basically fine tuning the oxygen content as the boiler load settles to a steady position. It should be noted that continuous automatic oxygen control responds to very small changes in oxygen. For that reason it is sometimes referred to as *oxygen trim control*. As such, it is not capable of effecting large changes to air flow. During changes to the boiler steam production initiated by a steam pressure change, the control scheme must manage air flow through other algorithmic means. *Figure 4 – Jackshaft Control with Oxygen Trim* represents this arrangement.

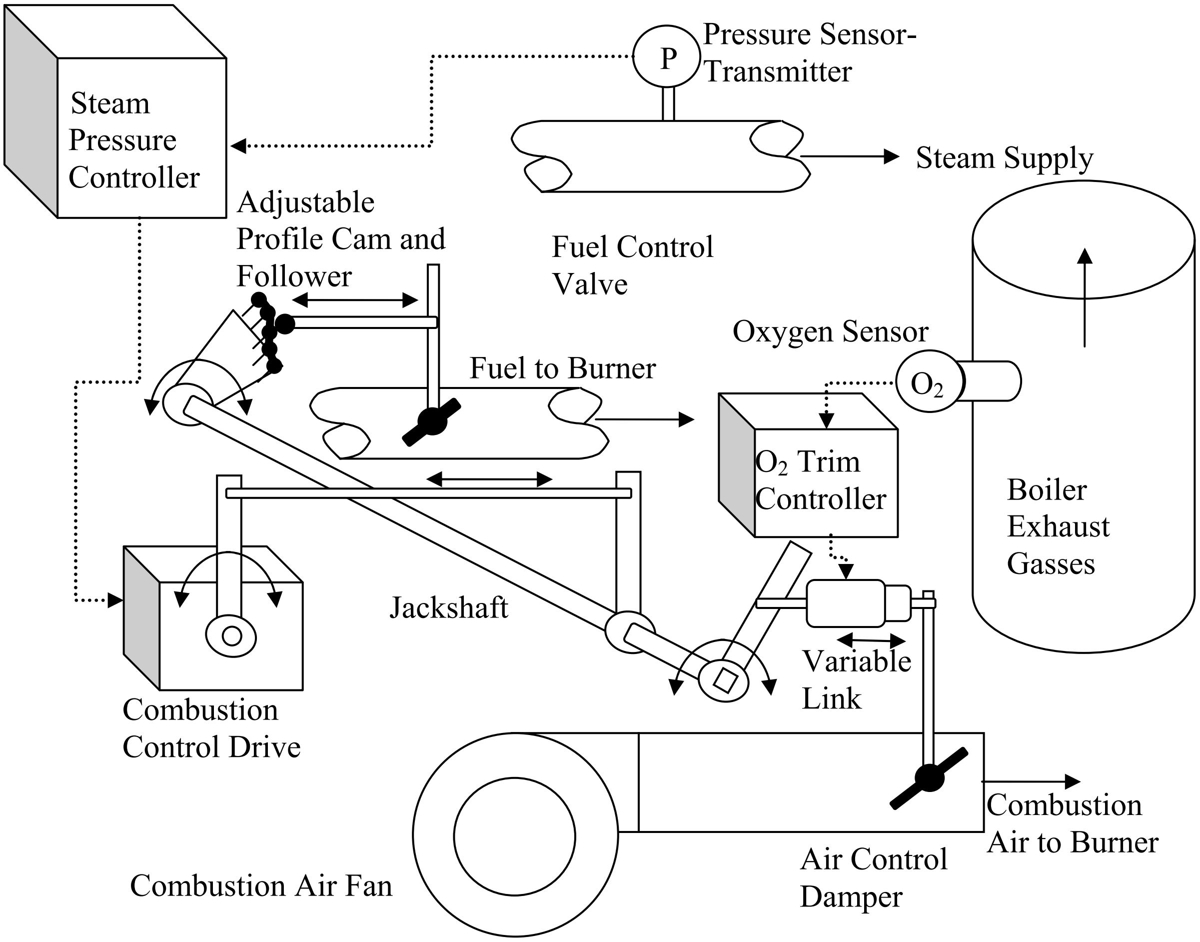

Figure 4 – Jackshaft Control with Oxygen Trim

Another common control arrangement is identified as *metered combustion control*. Simple metered combustion control operates with a similar philosophy to simple positioning control—combustion air flow is based on the fuel flow without flue gas oxygen content feedback. Metered combustion control incorporates a flow meter in the fuel flow and a flow meter in the combustion air flow. The controller takes the fuel flow rate measurement and controls the air flow rate based on an air-fuel ratio set point. The air-fuel ratio set point is generally varied with respect to boiler load to allow additional excess air at low loads. This control method generally provides more precise control than simple positioning control and it eliminates some of the ambient effects that can impact the combustion air mass flow. However, this form of combustion control is approached in a tune-up scenario with exactly the same philosophy as simple positioning control. Additionally, oxygen trim control is added to simple metering control in the same manner as it is added to simple positioning control (jackshaft control).

These control strategies take many forms and there are many variations of each but this description outlines the primary composition of the control. Below is a table containing the expected flue gas oxygen content for common fuels. This table (*Table 3 – Typical Flue Gas Oxygen Content Control Parameters*) has been developed from field observations of hundreds of boilers and should be taken as a simple representation of typical. It should be noted that most boilers require higher flue gas oxygen content at lower loads. This generally results from the fact that mixing is compromised in the burner at low loads. The oxygen concentrations are presented as "full gas sample" analysis and "dry gas sample" analysis. These designations are explained in the *Tools* section of this Guidebook.

Additionally, it should be noted that flue gas oxygen content targets may be influenced by environmental controls; such as, nitrogen oxides (NO_x) control. When a boiler is equipped with NO_x control the minimum oxygen concentrations are sometimes higher than if the boiler was equipped with a standard burner without NO_x control.

Typical Flue Gas Oxygen Content Control Parameters								
Fuel	**Automatic Control Flue Gas O_2 Content**				**Positioning Control Flue Gas O_2 Content**			
	Minimum		**Maximum**		**Minimum**		**Maximum**	
	Full Gas Sample [%]	**Dry Gas Sample [%]**	**Full Gas Sample [%]**	**Dry Gas Sample [%]**	**Full Gas Sample [%]**	**Dry Gas Sample [%]**	**Full Gas Sample [%]**	**Dry Gas Sample [%]**
Natural Gas	1.5	1.8	3.0	3.6	3.0	3.6	7.0	8.0
Numb. 2 Fuel Oil	2.0	2.2	3.0	3.3	3.0	3.3	7.0	7.6
Numb. 6 Fuel Oil	2.5	2.8	3.5	3.8	3.5	3.8	8.0	8.5
Pulverized Coal	2.5	2.7	4.0	4.3	4.0	4.3	7.0	7.4
Stoker Coal	3.5	3.7	5.0	5.3	5.0	5.3	8.0	8.4
Stoker Biomass-Wet	4.0	5.2	8.0	9.7	5.0	6.4	8.0	9.7
Stoker Biomass-Dry	4.0	4.4	8.0	8.6	5.0	5.5	8.0	8.6

Table 3 – Typical Flue Gas Oxygen Content Control Parameters

A primary function of boiler combustion control is to maintain safe operations of the combustion reaction. In order to accomplish this it is essential for the combustion controller to ensure that when the burner load is required to increase that the combustion air flow is increased first and the fuel flow follows. Similarly, when the burner load is required to decrease the fuel flow decreases first and is followed by a decrease in air flow. This control arrangement ensures the combustion zone will always have excess air.

4) Boiler Combustion Tune-Up

For a typical boiler with positioning control a tuning event will entail many activities with the primary focal point being the reestablishment of the relationship between fuel flow and air flow. The discussions that follow focus attention on improving the performance of simple positioning combustion control. Natural gas and light fuel oil are the principal discussion theme. However, it should be noted that the principles outlined are appropriate for any type of combustion control and any fuel. The example and discussion focus on simple positioning control is intended to present the basic philosophies associated with a boiler tune-up. These philosophies can be directly extended to all types of combustion control and all fuel types. *The primary philosophy applied is to challenge the existing equipment to provide the best practical performance with respect to energy efficiency and environmental emissions. After this, the challenge should be to explore improving, modifying, or replacing the equipment that is in-place to achieve the best practical performance.*

It must be reinforced that boiler operations in general and tune-up activities in particular are hazardous and require the skill and knowledge of experienced technicians. This Guidebook is in no way intended to advise a departure from the boiler or burner manufacturer's instructions and recommendations. Only qualified, experienced, knowledgeable personnel should be employed to complete a boiler tune-up.

The overarching mindset of this tune-up Guidebook is continuous improvement of the combustion management process to the point that best practice status is sustained. As a result, the recommended strategy for proper boiler tune-up is to identify and record the existing (as-found) performance conditions and to adjust the boiler to the most appropriate performance conditions. This should also entail recording the post tune-up operating parameters along with the adjustment that were required to attain the new operating conditions. Any failed components or control systems should be noted to ensure systemic problems are identified and eliminated. This method of record keeping will identify the improvement achieved and allow the tune-up frequency to be more confidently established. In other words, if the as-found conditions are significantly different than the post tune-up conditions then the tune-up frequency should be increased and the offending parts of the system should be revised, replaced, or eliminated.

There are many measurements required to complete a boiler tune-up. There are several critical measurements without which the tune-up activity cannot proceed. The critical measurements are flue gas oxygen concentration and flue gas combustibles concentration. These measurements are typically obtained with a portable combustion analyzer. The location of these measurements is a critical aspect of the tuning operation. This will be discussed in the *Measurement Locations* section of this Guidebook.

Additional flue gas component analysis is required when the environmental permit specifies limits on emission components. A common regulated emission component is nitrogen oxides (NOx). Often when nitrogen oxides are regulated combustibles will be regulated because the control of one affects the formation of the other.

Additional measurements can support the tune-up activity. Fuel flow rate and steam flow rate aid in the establishment of the operating range of the boiler. These measurements also support the establishment of the performance improvement opportunities associated with tuning the boiler.

Fuel supply measurements are essential to ensure external factors are not affecting the combustion process. A natural gas fired boiler will be equipped with a natural gas pressure regulator that is designed to maintain a constant pressure upstream of the natural gas flow control valve controlling the burner. If the natural gas supply pressure regulator is not maintaining a consistent pressure then the boiler tuning will be inconsistent—safety concerns will more importantly arise as well. As a result, it is important to measure the fuel supply pressure both upstream and downstream of the burner fuel control valve. In a similar manner the combustion air pressure (windbox pressure) should be measured.

4.1 Preparation

A boiler tune-up activity will require the boiler to operate at all points of its capacity range. This will require the boiler to operate an extended period of time (many minutes) at full-load, at minimum-load, and at several loading points in-between. This can present significant problems for single boiler facilities and for facilities with minimal steam production flexibility. As an example, a single boiler facility may be attempting a tune-up activity while the steam demand is relatively low. This situation could require steam venting to allow stable operation of the boiler while setting the tune-up parameters. Provisions must be made available to allow the tune-up process to safely and effectively progress through all of the loading stages of the boiler. These issues often significantly extend the amount of time required to accomplish a tune-up.

Often a steam vent must be equipped with a silencer to eliminate excessive noise. The vent may require the addition of an automatic control valve to ensure steam pressure remains within appropriate tolerances. The steam pressure tolerances are required not only for the general site operations but also to maintain consistent and repeatable boiler operations for the tune-up activities.

It is best to assemble design information for the boiler, burner, and combustion control equipment. Drawings and design specifications are key elements in understanding the characteristics and capabilities of the equipment. A review of the most recent and past tuning or repair reports can provide insights to the operating characteristics of the equipment. Photographs serve as excellent tools that clearly identify the conditions and components of the tune-up activities.

The environmental permit should be examined to identify the emissions constraints under which the boiler must operate. Typically nitrogen oxides (NOx) and combustible material (often identified as CO) are specifically addressed in the emission limits.

The boiler and steam system should be examined to ensure all components can safely operate during the tune-up process. The fuel delivery train and combustion air system should be inspected to ensure they are functioning properly with appropriate safeguards. All of these activities are essential; but, in-depth discussions in this area are considered beyond the focus of this text.

Support personnel requirements should be clearly identified along with the expected timeframe of the tune-up process. Personnel will be required to ensure the boiler is operating properly and safely during all aspects of the tune-up process. During this time the boiler must satisfy the site steam demands and maintain load conditions for the tune-up process. General support personnel may be required to aid in the tuning process. These personnel requirements should be clearly identified.

4.2 Measurement Locations

The schematic below is a simple representation of an example boiler burning a simple fuel such as natural gas. The locations of the flue gas measurements are an important factor in all boiler tune-up activities. In theory, the flue gas composition should be measured at the point the gases exit the combustion zone. However, this location is not a practical measurement site because access is limited and the temperature of the gas is elevated. As a result, the most common flue gas measurement location is immediately downstream of the steam generation section of a water-tube type boiler. For a fire-tube type boiler the flue gas sample is most commonly taken as the exhaust gases exit the boiler proper.

A point of concern is the variation of flue gas properties (composition, temperature, velocity) across the flow area. Flue gas samples should be taken at multiple locations across the flow field. If variation in the measured values is significant across the flow field then an appropriate strategy must be developed to accommodate the situation. The measurement location can be changed or the information can be compiled for the specific location. This situation can present significant tune-up difficulties.

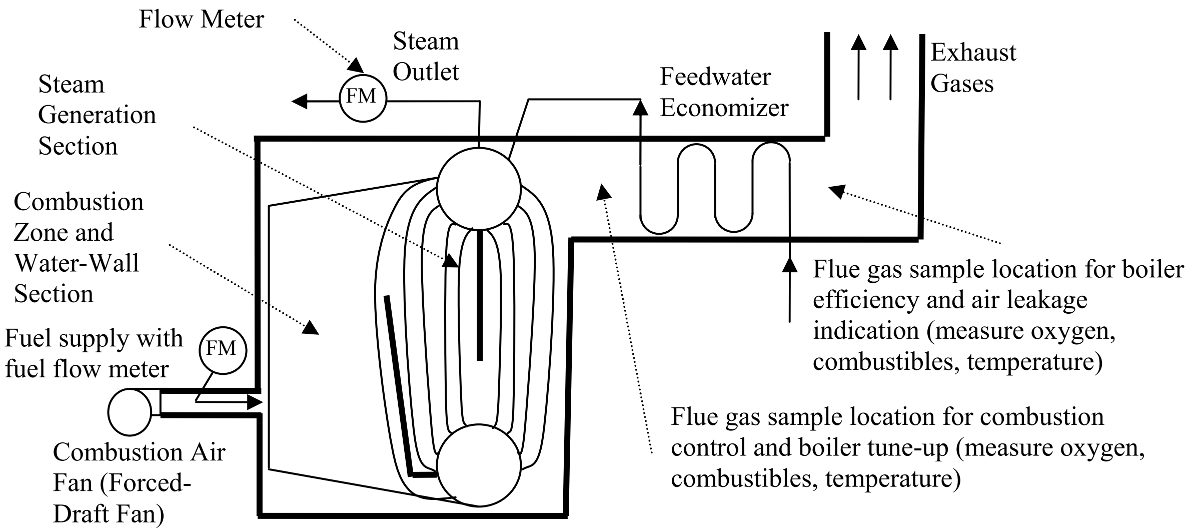

Figure 5 – Target Measurement Locations

The primary point of concern is to measure the flue gas component concentrations as they exit the combustion zone. Ambient air leaking into the exhaust gases can significantly change the flue gas composition. A boiler operating with a flue gas pressure that is less than ambient pressure will allow any opening to leak ambient air into the flue gas. This will; of course, impact the flue gas oxygen concentration. If the air leaks into the boiler outside the combustion zone then the air will not influence the combustion reaction. However, the air leakage has the potential to impact boiler efficiency. In fact, if the air leaks into the flue gas upstream of the last point of heat recovery then the boiler efficiency will be reduced. If the air leaks into the boiler downstream of the last point of heat recovery the primary impact will be an increase in fan energy, which is a loss but a minor loss.

The example boiler is equipped with a Forced Draft (FD) fan only and the flue gas passes through the boiler with a pressure greater than ambient pressure throughout. As a result, the location of the flue gas oxygen and flue gas combustibles measurements are not as critical as if the boiler were equipped with an Induced Draft (ID) fan or a significant stack effect that would reduce the pressure of the flue gas. In general it is good practice to obtain the flue gas samples as near to the combustion zone as practical. Because of access and instrumentation limitations the best practical location for sampling is most commonly found in the breeching as the flue gas exits the steam generation section.

Air leakage into the exhaust gases can significantly complicate combustion control and can mask boiler inefficiencies by quenching the final flue gas temperature. If air in-leakage is not considered, then unsafe conditions can result in the combustion zone when flue gas oxygen content is reduced. Boiler casing leaks and air heater leaks are probably the most common leak issues. Air leakage is much more of a problem in balanced draft boiler designs than in forced draft boiler designs; however, forced draft boilers can operate with flue gas pressures that are less than ambient pressure (this can result from the stack effect).

The exhaust gas composition and other properties will most probably vary across the flow stream. This should be given careful investigation because significant energy, environmental, safety issues can arise from poor or improper gas sampling. As stated previously, a traverse of the flue gas cross-section should be conducted to determine the degree of variation across the flow path. Significant variation will require multiple sampling positions or possibly a sampling technique that allows a combined sample to be taken. The sampling procedure used should be clearly noted to allow it to be used in the future to ensure consistent strategies are followed.

Combustion air heating is a common form of boiler efficiency improvement—these components can significantly impact the acceptable location of flue gas measurements for tune-up activities. Combustion air heaters commonly experience leaks. The leaks are most commonly combustion air leaking into the exhaust gases because the combustion air is typically at a higher pressure than the flue gas. Air heater leakage is typically more of a problem in rotating regenerative air heater units. Recuperative units are most commonly shell-and-tube designs, which greatly reduce the potential for leaks.

Regenerative air heaters are designed with moving and stationary components. Rotating regenerative air heaters are equipped with seals that are designed to leak a certain amount. Typically the rotary air heaters will leak combustion air into the flue gas stream because the combustion air is usually at higher pressure than that of the flue gas. Rotary regenerative air heaters leak by two primary methods—carryover and seal leakage. Carryover occurs as air is trapped in the volume between the plates of the rotating elements. This air will be discharged into the combustion gas stream. Likewise, combustion gas will carryover into the combustion air stream as the air heater segments move from the air side to the flue gas side. Typical designs will leak 5% to 15% of the total airflow to the combustion gas side. The design leakage rate will increase with wear. This can be diminished through the use of automatically adjusting seals. A problem with stationary seals is that they are set cold and the gap changes as the unit gains temperature.

The point of this combustion air heater discussion is that boilers that contain combustion air heaters, and especially regenerative air heaters, selection of the flue gas sample location is critical. The flue gas measurements used for the tune-up process must be taken upstream of the air heater. Tune-up activities on all boilers must consider air leakage.

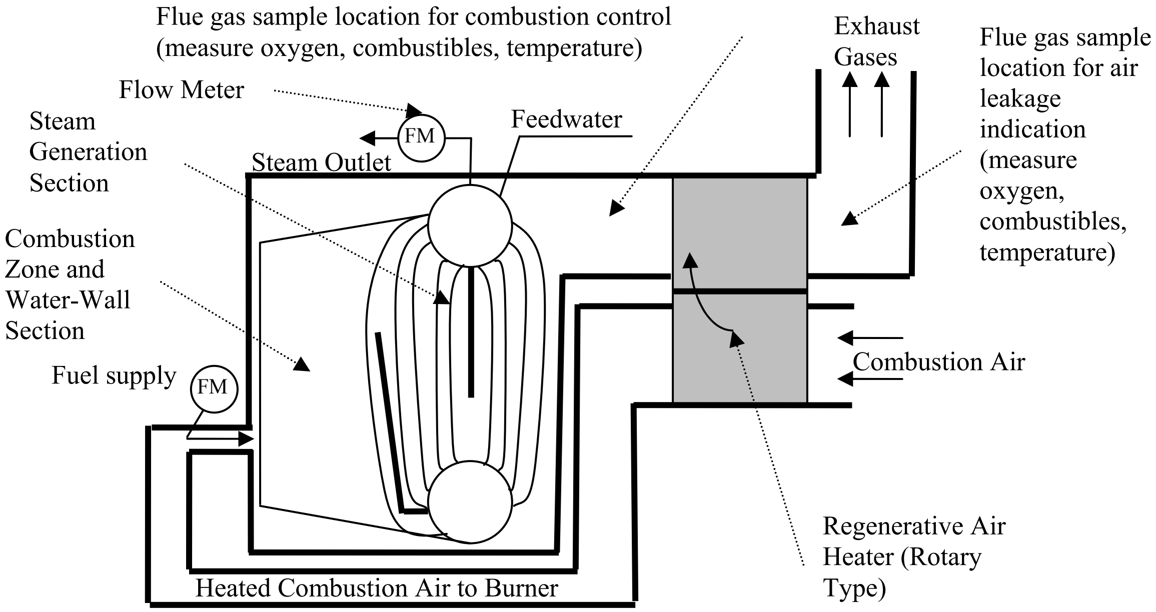

Figure 6 – Boiler and Regenerative Air Heater Measurement Locations

It should be noted that flue gas measurements must be considered average or nominal measurements. This generalization results from the fact that the flue gas component concentrations vary across the cross section of the duct through which the flue gas flows.

4.3 Tools

The primary tool required to complete a boiler combustion tune-up is a flue gas analyzer. The required measurements for an appropriate flue gas analysis are flue gas oxygen content, flue gas combustibles concentration, flue gas temperature, and ambient temperature. In many instances nitrogen oxides concentrations (NOx) are a required measurement. Even though all of the measurements are important, the principal measurements are flue gas oxygen content, combustibles content, and any components that are managed as a part of environmental compliance (NOx for example).

It should be noted that flue gas oxygen content is only an indication of excess oxygen. This point is important when considering burner functionality. A primary purpose of a burner is to mix the air and fuel to support combustion. Failure of burner components can allow oxygen and fuel to pass through the combustion zone without mixing and reacting. This will result in un-reacted oxygen measured in the exhaust gas and unburned fuel. As a result combustible concentration is also a critical measurement.

Oxygen measurements are generally provided from two types of instruments. It is important to note that the two types of instruments present different oxygen concentrations. The two most common field instruments used to measure flue gas oxygen concentration are zirconium oxide sensors and electrochemical sensors. A third type of sensor is a paramagnetic sensor; however, it is not typically used in industrial applications because of the rather delicate nature of the instrument.

Zirconium oxide type sensors measure the concentration of oxygen remaining after all combustible material has reacted in the complete gas sample. There are two important distinctions in this description. First, the zirconium oxide sensor operates at elevated temperature resulting in any combustible material in the gas sample reacting with the oxygen in the gas sample. This serves to reduce the measured flue gas oxygen content. However, the change in oxygen content is generally very small because the concentration of unburned fuel is very small in comparison to the amount of oxygen in the glue gas. Second, the zirconium oxide sensor measures the concentration of oxygen remaining in the entire gas sample. In particular, the oxygen concentration is measured with respect to the amount of water and all other components of the flue gas.

Conversely, electrochemical sensors measure the concentration of oxygen in the flue gas with the liquid water removed from the gas sample. The flue gas sample is drawn from the boiler exhaust and is then cooled. The water-vapor in the exhaust gas condenses and is removed as liquid water prior to the sample passing across the sensor. As a result, the oxygen concentration is measured on a dry-basis. Any combustible materials in the flue gas sample remain in the analysis.

Dry analysis and full gas sample (wet) analysis present different results for the same gas sample. As an example, consider a flue gas composed of oxygen, water-vapor, carbon dioxide, and nitrogen. If the sample is composed of 5.0% oxygen, 15.0% water-vapor, 10.0% carbon dioxide, and 70.0% nitrogen, then the wet-basis (full gas sample) oxygen concentration is 5.0%. However, if the gas concentration is measured with an electrochemical sensor then the water-vapor is removed from the sample. As a result, the dry-basis oxygen measurement will be 5.9%. The table below presents the example information.

Flue Gas Component	**Full Gas Sample Concentration [% Volume]**	**Dry-Basis Sample Concentration [% Volume]**
O_2	5.0	5.9
H_2O	15.0	0.0
CO_2	10.0	11.8
N_2	70.0	82.4

Table 4 – Wet-Basis versus Dry-Basis Example

It is important to understand the differences in the sensor technologies; however, it is most important to complete any analysis with consistent data. It is also good to note that the zirconium oxide technology is the most common technology employed for permanently installed (in-situ) continuous monitoring of flue gases. Zirconium oxide sensors have the advantage of quick response time because the sensor does not require the gas sample to be cooled (only filtered). Also, the sensor has an almost unlimited shelf-life. Alternately, the electrochemical sensor will become depleted as the cell materials react with the flue gas components. As a result, frequent cell replacement is required. Electrochemical sensors are the dominant technology used in portable combustion analyzers [18]. If the boiler is equipped with automatic oxygen control, and if the tune-up measurement tool is of a different type than the in-situ measurement device, then the differences in readings between the two should be taken into account when establishing excess air safety factors—all measured values should be recorded during the tuning process.

Similarly, combustibles measurements are completed with various instruments. The three prevalent methods for measuring combustibles in flue gas are with a catalytic element, electrochemical cell, and non-dispersive infrared absorption. As with oxygen measurement the electrochemical sensor must receive a dry sample. Electrochemical sensors are the dominant technology used in portable combustion analyzers. Electrochemical sensors and infrared technologies measure only carbon monoxide. Carbon monoxide is generally the dominant component of combustible material; however, it is common to assume total combustible material is composed of ⅔ carbon monoxide and ⅓ hydrogen.

Gas analysis equipment along with all of the other measurement tools used in the boiler tune-up process must be properly calibrated prior to use. The instruments should be maintained in proper operating condition and tested to ensure accurate performance.

As a point of note, observing and evaluating flame appearance is a vital part of the tune-up process. Flame characteristics can provide very useful information about the burner condition and operating characteristics in the combustion zone. However, flame characteristics are not a reliable tool for tuning the combustion process—flue gas analyzers are the primary tool required to complete the tuning process. Flames will exhibit a wide array of characteristics based on many factors some of which are not related to combustion chemistry performance.

4.4 Identification of As-Found Conditions

Clearly identifying the as-found conditions along with the post tune-up conditions allow the boiler owner to evaluate the requirements and effectiveness of the tune-up process. In other words, if the tune-up activity resulted in significant changes to the control positions then tune-ups should be completed on a more frequent basis. Additionally, a comparison of as-found to post tune-up information can point out shortcomings in the system equipment. This comparison is also an indication of the effectiveness of the tune-up technician. In order to accomplish this before-and-after comparison a clear identification of the as-found conditions must be developed.

Identification of the as-found conditions centers on measurement of the operating parameters of the combustion process that will be modified during the tune-up process. The boiler will have to be operated through the full range of operating conditions and system measurements will be recorded for all applicable operating conditions. This includes all firing positions from minimum-fire to maximum-fire. The primary measurements are as noted before—flue gas oxygen content, flue gas combustibles content, specific environmental emissions components, fuel flow rate (or steam flow rate), and various additional informative measurements.

As mentioned previously, prior to initiating a tune-up activity the operation and function of all of the combustion control components must be understood and verified to be performing properly. The fuel safety and control components must ensure that fuel is being presented to the fuel control valve with appropriate fuel pressure for all load conditions.

Visual observations of the flame are also indicative of performance. Flame color, flame intensity, combustion zone impingement, pulsations, smoke, and flame detachment are all indicators of needed corrective actions. All fuel injection points should demonstrate combustion—areas with no flame generally indicate plugged fuel nozzles. Fuel nozzles can become misaligned and can be discharging fuel away from the combustion zone. Poorly atomized liquid fuels can spray large droplets of fuel far into the combustion chamber or onto the walls of the boiler. Photographs can be a very useful tool in the flame condition evaluation process.

The table that follows represents as-found field information for an example boiler. In the example, the positioning combustion controller is equipped with 10 adjustment pins. Measurements are recorded for operations “at each pin”.

Boiler Tune-Up Field Data	
Location	Example
Boiler Designation	Boiler Number 1
Date	Sep-2-2011

General Description and Observations:

The table below indicates typical data for common positioning control with natural gas as the fuel.

The data represents before the positioning control was tuned (as-found).

Boiler steam generation capacity is 25,000 lbm/hr saturated steam at 125 psig.

Fuel:	Natural Gas
Flue Gas Oxygen Measurement:	Dry Basis
Fuel Atomization:	Not Required

Data	**Units**	**Firing Position 1-Low Fire**	**Firing Position 2**	**Firing Position 3**	**Firing Position 4**	**Firing Position 5**	**Firing Position 6**	**Firing Position 7**	**Firing Position 8**	**Firing Position 9**	**Firing Position 10-High Fire**
Flue Gas O_2	[%Dry]	6.9	6.6	4.9	5.6	7.6	8.4	8.5	8.7	8.8	9.1
Final Flue T	[°F]	350	364	390	399	424	432	439	446	446	450
Ambient T	[°F]	70	70	70	70	70	70	70	70	70	70
Combustibles	[ppm]	5	5	8	9	6	9	5	2	1	1
Fuel P to Cont V	[psig]	50	50	50	50	50	50	50	50	50	50
Fuel P to Brnr	[in H_2O]	2.3	4.1	6.5	9.4	12.8	16.9	19.1	21.5	24.0	26.8
Atomizing P	[psig]	0	0	0	0	0	0	0	0	0	0
Fuel T	[°F]	70	70	70	70	70	70	70	70	70	70
Steam Pressure	[psig]	125	125	125	125	125	125	125	125	125	125
Steam Temp	[°F]	353	353	353	353	353	353	353	353	353	353
Steam Flow	[lbm/hr]	8,100	10,700	13,400	16,000	18,300	20,700	21,900	23,100	24,300	25,500
Fuel Flow	[sft^3/h]	400	550	700	850	1,000	1,100	1,200	1,250	1,350	1,400
Windbox Press	[in H_2O]	0.5	0.9	1.1	2.5	4.4	6.5	9.0	11.0	12.0	12.5
Flame Notes		Blue w/yellow	Blue	Blue	Blue	Blue	Blue	Blue	Small w/yellow	Small w/yellow	Small w/yellow
Flue Gas NOx	[ppm]	3	3	3	5	5	5	6	5	7	6

Table 5 – Boiler Field Data As-Found

Part of the as-found investigation should be a visual inspection of the burner internal components as well as the combustion control components. Most burners have minimal opportunity for adjustments and modifications; however, an evaluation should be made to ensure all of the components are properly installed and are not damaged. Many burner designs require somewhat precise alignment between mixing diffusers and fuel injection components. Photographs are useful in documenting the condition of the burner and burner throat areas.

The as-found data should be evaluated to determine the performance characteristics of the boiler. Deficiencies in the combustion characteristics will aid in defining the tune-up strategy. For example, if the flue gas oxygen content is considered appropriate for the firing rate but the concentration of combustibles is excessive then the physical components of the burner will be a critical part of the investigation. The combustibles concentrations are expected to remain low throughout the operating range of the boiler for properly tuned performance. It is also expected that the flue gas oxygen content should decrease smoothly as the firing rate is increased from low-fire to high-fire. The control component profiles (adjustable cam or control equation) should present as smooth contours—sharp bends are indicative of potential problems.

The example as-found data in *Table 5 – Boiler Field Data As-Found* indicates the amount of excess air is excessive at elevated firing rates. This is seen as flue gas oxygen content is significantly greater than the expected values (*Table 3 – Typical Flue Gas Oxygen Content Control Parameters*). Additionally, the combustibles concentration presents a baseline that is very low. This indicates the burner is capable of mixing the air and fuel to provide excellent combustion with lower flue gas oxygen content. In other words, this example data is indicative of a boiler that has a high probability of benefiting from a tune-up. In some cases, the as-found data might suggest the need for an internal inspection prior to proceeding with the tune-up.

4.5 Tune-up

The tune-up activity is the act of ensuring the burners are properly mixing the air and fuel and of reestablishing the most appropriate amount of excess air throughout the operating range of the boiler. The description in this section will focus on the tuning process for a boiler operating with simple positioning control. This control method was introduced in the *Combustion Control Strategies* section of this Guidebook and the component schematic is reproduced below. The positioning control system in this example is equipped with a variable adjustment cam on the fuel control valve positioner.

Even though this tune-up discussion is based on simple positioning control the philosophy and strategies are equally applicable to all combustion control types. The primary strategy is to identify the as-found operating conditions, challenge the existing equipment to perform at a level that is as good as practical, and to evaluate if additional modifications are warranted. In many arrangements the physical components of the *adjustable profile cam and follower* are replaced with control logic within an electronic controller.

It is assumed in this Guidebook that the boiler has been in operation and that major modifications to the combustion train are not needed. It should be noted that if these modifications are necessary then the manufacturer's recommendations should be followed to establish the general operating conditions of the boiler. The combustion air flow should vary linearly with respect to the combustion control scheme. The final control device (damper, Inlet Guide Vanes, variable speed, or other) may operate in a pre-defined nonlinear fashion. But, if the actual air flow does not vary linearly as required, then adjustments may need to be made to the control device or other system component (in accordance with the manufacturer's recommendations) to reestablish linear air flow response characteristics.

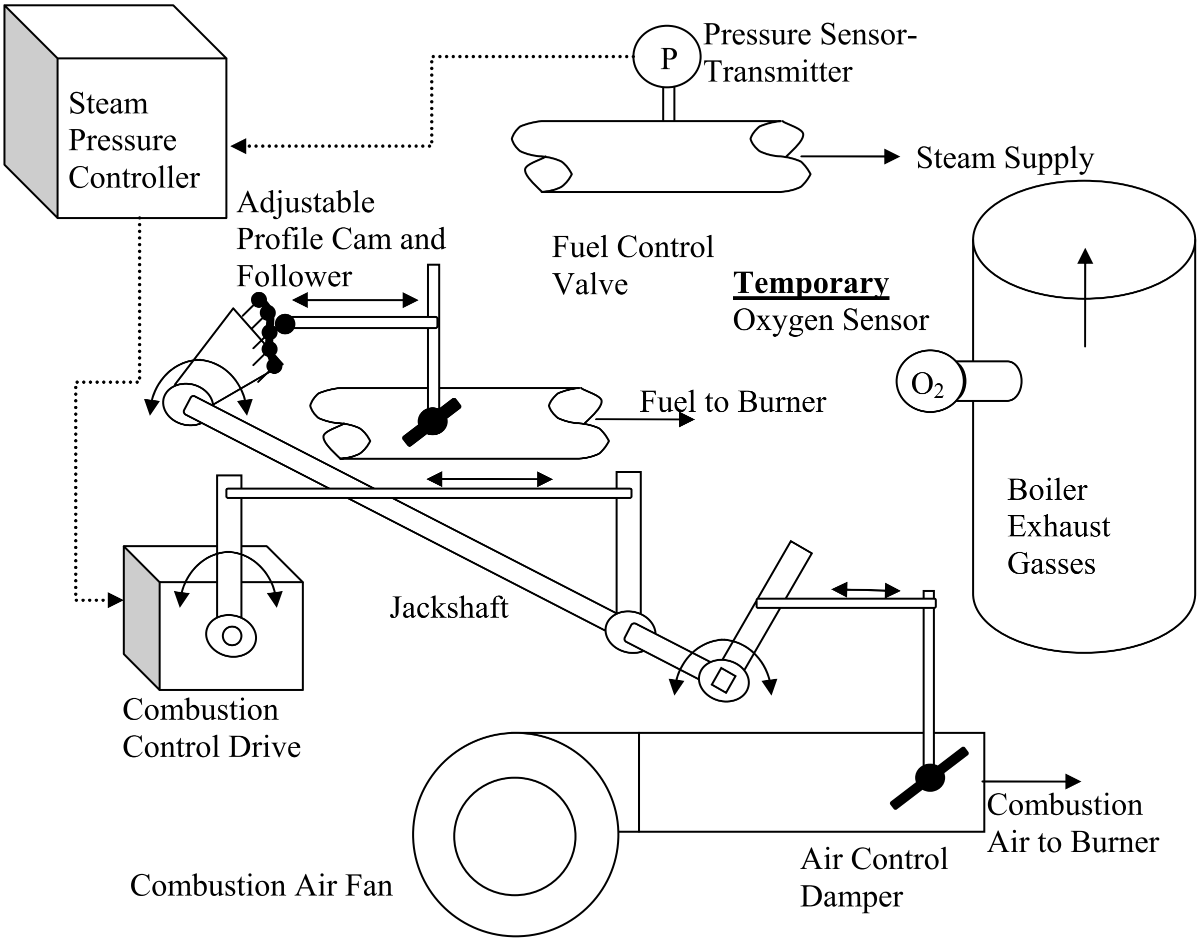

Figure 7 – Simple Positioning Control Schematic

As a point of note, all adjustments made during the tuning process should be relatively small. All adjustments should be made by trained competent technicians. The tune-up technician should be skilled in the evaluation and adjustment of the specific boiler and burner equipment in use. Boiler operating conditions should be monitored to ensure the combustion zone conditions are not becoming fuel-rich, which can lead to an explosion. The flame condition should be observed to ensure that flame intensity is appropriate and that there is no flame impingement. The boiler should be allowed to stabilize at each firing point before operating data is recorded and before the adjustment process is initiated.

The primary adjustment made in this boiler tune-up is to the position of the combustion control adjustable cam. Boilers with other control types will require a different form of adjustment but the adjustment strategy and investigation techniques are the same. Typically, this device is mounted on the control jack-shaft and is a rotating element. The jackshaft will generally rotate approximately 90 degrees from low-fire through high-fire. The cam is typically composed of several pins that can be adjusted to change the profile of the cam—10 to 15 pins are common.

Figure 8 – Adjustable Profile Cam and Follower at Low-Fire Position is a schematic representation of the fuel positioner cam in the low-fire position. The jackshaft is rotated by the primary control motor through about 90° to the high-fire position noted in *Figure 9 – Adjustable Profile Cam and*

<u>*Follower at High-Fire Position*</u>. There are usually several pins on the cam between low-fire and high-fire that allow the profile to be adjusted during the tuning process. In the example 10 pin cam, pin 1 represents the low-fire position relationship and pin 10 represents the high-fire position relationship. The tuning activity will establish the height of each pin in the profile that appropriately positions the fuel flow control device for the corresponding air control device position.

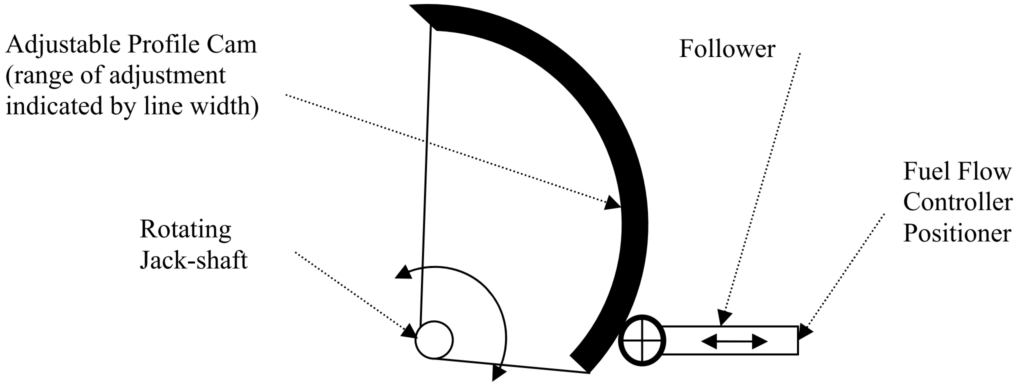

Figure 8 – Adjustable Profile Cam and Follower at Low-Fire Position

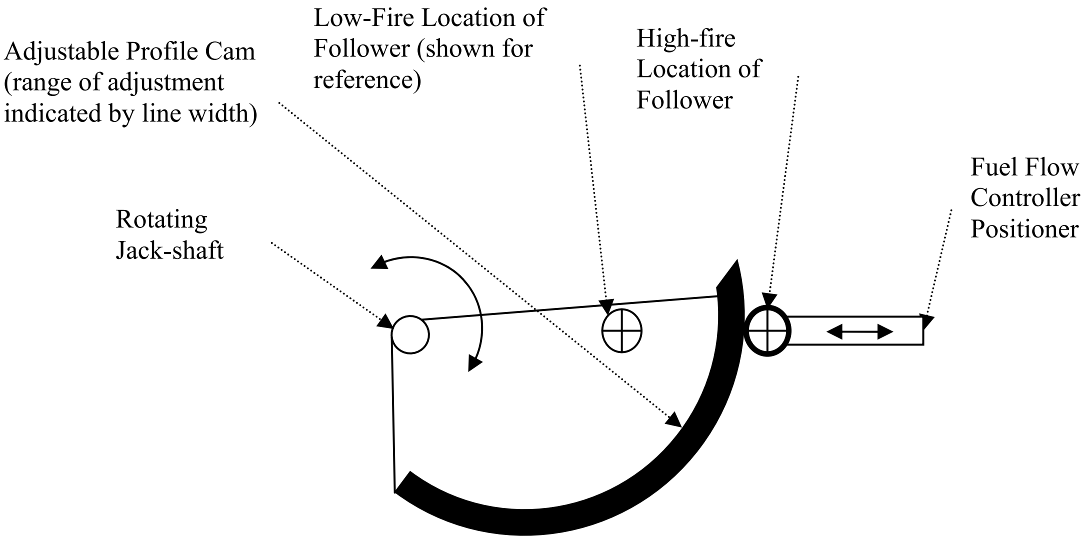

Figure 9 – Adjustable Profile Cam and Follower at High-Fire Position

The tune-up will attack each position of the combustion controller individually (each pin in this example). In the example of this text the combustion controller holds the position of the air flow control device fixed and allows adjustments to be made to the fuel flow. This is probably the most common positioning control arrangement in-use today.

The tune-up strategy for each firing position should be composed of three steps. The tuning process initiates with the air flow held constant; in other words, the jackshaft position is manually held constant, which holds the air flow control position constant. Flue gas measurements are taken to establish the operating conditions of this firing position. Immediate adjustments may be required if the combustion is occurring with minimal excess air and unburned fuel concentrations are elevated. In this case the fuel control position should be adjusted to reduce fuel flow and achieve elevated excess air.

The second step is to increase the fuel flow at fixed air flow until the combustibles concentration begins to increase appreciably. This establishes the minimum air-fuel requirements for the firing position. Third, the fuel flow rate should be decreased (at fixed air flow) to apply an appropriate excess air safety factor. These three steps set the position relationship between air and fuel for one firing position. This process is repeated for each firing position. Operational data should be recorded for each firing position.

The excess air safety factor is required because of many reasons (especially for positioning control). Probably the most common and critical reasons for the safety factor are related to changes in combustion air mass flow. It is interesting to note that the combustion air fan is basically a constant volume flow device when operating at a set control position. If the air temperature entering the fan increases significantly then the volume flow of air entering the burner will remain essentially constant; but, the mass flow of air will decrease. This situation can result in insufficient oxygen in the combustion zone and a potentially explosive arrangement. This ambient air temperature effect is also a reason that seasonal tune-ups are recommended.

Alternately, if the tune-up process is completed with the boiler room open to the ambient surroundings, then the combustion air flow can be significantly reduced if the boiler room is closed. In other words, the tune-up process can take place during a time when the boiler room doors and windows are open. The boiler may be required to operate when the boiler room doors and windows are closed. This will result in a drop in the combustion air pressure entering the fan, which will decrease the air flow for a given air control position.

Generally, positioning control will require a minimum of 1.0% added to the oxygen value as a safety factor. Commonly 2.0% and even 3.0% safety factor values are used. As an example the oxygen content may be reduced to $2.0\%_{dry}$ before a significant increase in combustibles concentration occurs. A safety factor of 2.0% is applied to the minimum value. The result would be the final flue gas measurement of $4.0\%_{dry}$ for the position in focus.

The tuning process typically begins with the high-fire condition. The combustion controller is manually adjusted to the full-load pin. The most appropriate method available to ensure the full-load condition of the boiler is suitably set is to incorporate a properly calibrated fuel flow meter for the burner. A steam flow meter can provide acceptable information if a fuel flow meter is not available. However, it should be noted that output steam energy is not a direct indication of input fuel energy. Steam output energy is indicative of fuel input energy multiplied by boiler efficiency (*Equation 1*).

Tuning methods that do not incorporate fuel flow measurement or steam flow measurement must carefully investigate all operating characteristics to ensure the boiler is not operating above rated capacity and that the boiler is capable of meeting rated capacity. Manufacturer’s information, fuel control device characteristics, flue gas temperatures, and flame appearance are all indicators that must be considered.

Once the high-fire position relationship has been established then the individual high-fire pin position will be locked into place (pin 10 in this example). This typically occurs by setting a setscrew, locking the position relationship of the mechanical components. This single point position establishment procedure will require several minutes to complete the measurements, adjustments, and positioning.

Next, the combustion control position will be manually adjusted to the next adjustment pin and air flow control position. Once the boiler operations have stabilized at this new fuel load the position relationship establishment technique is repeated. The procedure is repeated through the full range of boiler operations. The adjustable profile cam should present a smooth transition profile throughout the operating range of the boiler.

It is very important to note that as the fuel supply decreases the excess air requirement for proper combustion increases. This results from the fact that the mixing of air and fuel occurring in the burner diminishes as the fuel and air flows decrease. As a result, additional excess air must be added to the combustion zone. Low-fire operations may require $6.0\%_{dry}$ to $7.0\%_{dry}$ oxygen in the flue gas for proper combustion. The data below (*Table 6 – Boiler Field Data Post Tune-Up*) represents the post-tune-up data for the example boiler. This data is considered typical for a boiler operating with positioning control. However, it should be noted that all equipment has limitations and varying operating characteristics that may preclude excellent performance throughout the control range. If there are operating positions that result in significant deviation from expected values then the root-cause of the problem should be identified and eliminated.

Generally environmental regulations require the flue gas combustibles concentration for natural gas combustion to be less than 200 ppm (at $3\%_{dry}$ O_2). Some regulations allow natural gas combustibles to be less than 400 ppm (at $3\%_{dry}$ O_2). However, for natural gas and light fuel oil combustion these limits are often relatively high. It is best to establish the baseline combustibles concentration for the individual combustion equipment and the fuel being burned. Then the combustibles baseline can be used as an indicator of deviation from baseline during the tuning process. Deviation might point to an equipment problem, or the opportunity to safely improve the boiler efficiency and reduce fuel cost.

Boiler Tune-Up Field Data

Location	Example
Boiler Designation	Boiler Number 1
Date	Sep-2-2011

General Description and Observations:

The table below indicates typical data for common positioning control with natural gas as the fuel.

The data represents after the positioning control was tuned (post-tune-up).

Boiler steam generation capacity is 25,000 lbm/hr saturated steam at 125 psig.

Fuel:	Natural Gas
Flue Gas Oxygen Measurement:	Dry Basis
Fuel Atomization:	Not Required

Data	**Units**	**Firing Position 1-Low Fire**	**Firing Position 2**	**Firing Position 3**	**Firing Position 4**	**Firing Position 5**	**Firing Position 6**	**Firing Position 7**	**Firing Position 8**	**Firing Position 9**	**Firing Position 10-High Fire**
Flue Gas O_2	[%Dry]	5.8	5.7	5.6	5.5	4.9	4.5	4.0	3.8	3.5	3.6
Final Flue T	[°F]	350	362	389	398	424	432	439	445	446	450
Ambient T	[°F]	70	70	70	70	70	70	70	70	70	70
Combustibles	[ppm]	2	2	2	2	2	2	2	2	2	2
Fuel P to Cont V	[psig]	50	50	50	50	50	50	50	50	50	50
Fuel P to Brnr	[in H_2O]	2.3	4.1	6.6	9.3	12.4	15.9	17.7	19.7	21.7	24.1
Atomizing P	[psig]	0	0	0	0	0	0	0	0	0	0
Fuel T	[°F]	70	70	70	70	70	70	70	70	70	70
Steam Pressure	[psig]	125	125	125	125	125	125	125	125	125	125
Steam Temp	[°F]	353	353	353	353	353	353	353	353	353	353
Steam Flow	[lbm/hr]	8,100	10,700	13,400	16,000	18,300	20,700	21,900	23,100	24,300	25,500
Fuel Flow	[sft^3/h]	400	550	700	850	950	1,100	1,150	1,200	1,300	1,350
Windbox Press	[in H_2O]	0.5	0.9	1.1	2.5	4.4	6.5	9.0	11.0	12.0	12.5
Flame Notes		Blue Yellow Tip	Blue Flame Yellow at Tip	Agitated Blue	Agitated Blue	Agitated Blue	Agitated Blue	Agitated Blue	Agitated Blue	Agitated Blue	Agitated Blue
Flue Gas NOx	[ppm]	5	5	5	6	7	7	8	8	8	8

Table 6 – Boiler Field Data Post Tune-Up

Caution should be exercised in minimizing low-fire flue gas oxygen content. National Fire Protection Association (NFPA) regulations require the minimum combustion air flow to exceed 25% of full-load airflow at all times under all operating conditions [20].

Burners that incorporate low NOx combustion control components will require additional tuning effort and measurements. Nitrogen oxides control commonly takes the form of Flue Gas Recirculation (FGR), staged combustion, or other control mechanism. The physical activities associated with these tuning events will be more involved than the simple description noted here; however, the philosophy is the same.

After all points of the positioning controller have been properly tuned the operational characteristics must be verified. This is accomplished by returning the control to each point in the control range. Operational data should be recorded for each point to verify proper functionality. If the combustion control system is a jackshaft arrangement then the components should be secured in their tuned locations to ensure the position relationships are maintained.

Tuning event timing should, at a minimum, conform to a schedule that is set to anticipate the need for a tune-up, such as seasonal changes. Additional tune-ups may be triggered by a significant change in the operating characteristics of the boiler. An excellent strategy is to utilize a portable combustion analyzer to check the performance characteristics of the boiler frequently—the frequency is based on the amount of change observed in the operating data. These frequent (yet simple) checks will identify problems and trigger a tuning event.

This discussion has assumed the combustion air fan is equipped with a flow control damper that utilizes friction to manage air flow to the burner. There are other common air flow control mechanisms; such as, fan Inlet Guide Vane dampers and variable speed control. These control mechanisms generally present fan energy efficiency improvements when compared to frictional damper control. The tuning activities follow exactly the same strategy as outlined here regardless of the air flow control mechanism.

Many boilers do not operate with modulating control—control that modulates the fuel and air input to the boiler ranging from low-fire up to high-fire. Many boilers operate with high-fire, low-fire, off control. With this type of control the primary points of concern are high-fire and low-fire; however, the boiler must transition safely between these two operating points. As a result, the tune-up process must consider all points of the controller (with special efficiency focus on high-fire and low-fire).

There are many different types of combustion control arrangements, as has been pointed out in this Guidebook. Electronic combustion controllers are available that accomplish positioning control without the jackshaft arrangement. The position of the fuel control device is set electronically for a given position of the air flow control device. Metered positioning control is available along with many forms of oxygen trim control. These control systems are tuned according to the same philosophy as described here—most of these control systems provide more flexibility than simple jackshaft control—but the tune-up philosophy is the same as simple positioning control.

4.6 Tune-up Checklist

The following is a simple checklist that highlights the basic activities and requirements associated with a boiler tune-up. The checklist is intended to be a time ordered tool to aid in planning and conducting boiler tune-ups.

1) Preparation
    a) Clearly identify the target equipment along with the intent and goals of the tune-up.
    b) Assemble boiler drawings and data sheets.
    c) Assemble burner drawings and data sheets.
    d) Assemble combustion control information.
    e) Identify environmental regulations and limitations.
    f) Become familiar with the target boiler and the general steam system.
    g) Identify steam production control strategy that will be used during the tune-up.
        i) Boiler and steam system operation support.
        ii) Steam demand control will be managed by a secondary boiler or steam venting will be used.
    h) Identify in-situ instrumentation and verify calibration.

- i) Identify measurement locations, verify access, and acquire instrumentation.
- j) Establish tune-up timeframe.

2) As-found observation
    - a) Examine the combustion control components and identify any defects.
    - b) Examine the burner internal components and identify any defects.
    - c) Examine the general boiler conditions and identify any defects.
    - d) Measure and record the following for each operating position of the combustion control system.
        - i) Observe flame pattern, flame dimensions, and burner condition.
        - ii) Flue gas oxygen content.
        - iii) Flue gas combustibles content.
        - iv) Flue gas emissions content (NOx and others).
        - v) Emissions control settings.
            - (1) Flue Gas Recirculation flow settings (if applicable).
        - vi) Fuel flow rate.
        - vii) Windbox pressure.
        - viii) Fuel pressure supplied to combustion control valve.
        - ix) Fuel pressure supplied to the burner.
        - x) Fuel atomizing media pressure (if applicable).
        - xi) Fuel supply temperature.
        - xii) Final flue gas temperature.
        - xiii) Ambient temperature.
        - xiv) Steam conditions (pressure and temperature).
        - xv) Steam flow rate.
    - e) Finalize the tune-up strategy.
    - f) Document any modifications completed at this point.

3) Tune-up
    - a) Tune-up each operating position of the combustion control system (from high-fire through low-fire).
        - i) Establish steady operation for the target operating point.
        - ii) Adjust combustion control position relationship to achieve desired combustion characteristics.

        - (1) Flue gas oxygen content target will generally vary with respect to load.
            - (a) Oxygen target safety factor must be applied to allow for changes in ambient conditions and equipment.
        - (2) Combustibles content.
        - (3) NOx content.
            - (a) Adjustments for emissions control are generally completed after combustion adjustments are established.
        - (4) Additional emissions component adjustments are completed if required.
    - iii) Measure and record the following for each operating position of the combustion control system.
        - (1) Observe flame pattern, flame dimensions, and burner condition.
        - (2) Flue gas oxygen content.
        - (3) Flue gas combustibles content.
        - (4) Flue gas emissions content (NOx and others).
        - (5) Emissions control settings.
        - (6) Fuel flow rate.
        - (7) Windbox pressure.
        - (8) Fuel pressure supplied to combustion control valve.
        - (9) Fuel pressure supplied to the burner.
        - (10) Fuel atomizing media pressure (if applicable).
        - (11) Fuel supply temperature.
        - (12) Final flue gas temperature.
        - (13) Ambient temperature.
        - (14) Steam conditions (pressure and temperature).
        - (15) Steam flow rate.
    - iv) Document any modifications completed at each point.

4) Post tune-up confirmation
    - a) Operate the boiler at each combustion control position, measure and record all data to verify the combustion control system is stable and robust.
        - i) Measure and record the following for each operating position of the combustion control system.
            - (1) Observe flame pattern, flame dimensions, and burner condition.

(2) Flue gas oxygen content.

(3) Flue gas combustibles content.

(4) Flue gas emissions content (NOx and others).

(5) Emissions control settings.

(6) Fuel flow rate.

(7) Windbox pressure.

(8) Fuel pressure supplied to combustion control valve.

(9) Fuel pressure supplied to the burner.

(10) Fuel atomizing media pressure (if applicable).

(11) Fuel supply temperature.

(12) Final flue gas temperature.

(13) Ambient temperature.

(14) Steam conditions (pressure and temperature).

(15) Steam flow rate.

5) Impact evaluation

a) Evaluate the economic impact of the tune-up.

b) Evaluate the environmental impact of the tune-up.

c) Challenge the potential to upgrade the combustion control system.

6) Document tune-up.

a) Document the tune-up including the following.

i) As-found conditions.

ii) Post tune-up conditions.

iii) Modifications and repairs completed.

iv) Recommended investigations and modifications.

v) Identified shortcomings of the equipment.

5) Boiler Efficiency Improvement Impacts

The effectiveness of a boiler tune-up is represented in the control of excess air throughout the boiler operating range. In other words, the performance of a boiler tune-up is identified by the flue gas oxygen content, the unburned fuel concentration, and the environmental emissions parameters. However, it is often required to identify the impact that the tuning event had on boiler energy consumption.

In theory, a comparison of fuel consumption at constant steam production will identify the boiler energy impact. However, it is very common for a direct fuel measurement to not present a viable measurement solution. There are many reasons for this situation. Often the reason is that fuel flow measurement is not in-place on the individual boiler. Even if fuel measurement is in-place the change in fuel flow rate as a result of a boiler tune-up is often less than 1%, which is very difficult to discern using industrial metering arrangements. The number of variables associated with boiler operation along with the variation in boiler conditions commonly makes a direct measurement of the fuel consumption impact impractical. However, it should be noted that if direct fuel flow measurement can be accomplished accurately then the direct fuel flow measurement analysis can be effective.

An indirect efficiency impact evaluation technique is outlined here. This evaluation method is useful in evaluating boiler performance impacts even when fuel flow measurement and steam flow measurement are not in-place on the boiler. It must be noted that more direct measurements result in a higher probability of obtaining accurate results. But, it is also good to note that this method can be used with minimal data to provide a general estimate of the impact of a tune-up to boiler operations.

The indirect efficiency impact analysis outlined here can be accomplished with simple and robust measurements. This analysis technique is capable of providing accurate and repeatable results. The efficiency impact evaluation is accomplished by applying the stack loss analysis techniques introduced in the *Boiler Stack Loss* section of this Guidebook.

This section of the Guidebook is not intended to be an exhaustive treatment of boiler efficiency analysis. The intent is to identify a simple method to provide excellent estimates of the efficiency impact associated with a boiler tune-up. The analysis method presented is thermodynamically rigorous; but, it is presented in a simplified manner.

While the discussion to this point has been focused on boiler efficiency improvement, it is of critical importance to also identify the economic impact associated with a boiler tune-up. As a result, this discussion of boiler efficiency impact will also identify the impact on fuel purchases, which represents the economic impact of a boiler tune-up. This type of analysis can also be used to identify the potential impact associated with changing the boiler combustion control—such as, upgrading from positioning control to oxygen trim control.

In order to appropriately identify the energy and economics impacts associated with a boiler tune-up an analysis must be completed that accurately reflects the as-found and post tune-up conditions. The analysis is required to determine the amount of fuel required to produce a specific amount of steam. The direct comparison is the amount of fuel required to produce steam in the as-found conditions versus the amount of fuel required to produce the same amount of steam in the post tune-up conditions.

In most real-world tune-up examples many parameters change from the as-found conditions to the post tune-up conditions. In the previous sections of this Guidebook (*Tune-up*) an example was presented of a boiler with simple positioning control. The positioning control was accomplished with the familiar jack-shaft arrangement with the adjustable cam on the fuel control valve positioner. In this type of arrangement it is possible for a tune-up activity to result in the airflow for each position of the cam to remain constant. This results from the fact that the airflow control position remains constant for a firing position from as-found to post-tune-up. In other words, at high-fire the as-found airflow could be 8,900 sft³/min and the post tune-up high-fire airflow could be the same (8,900 sft³/min). However, it should be noted that even though the airflow remains constant the fuel flow rate for the high-fire condition will change. Additionally, the steam production rate at the high-fire condition will change.

In fact, the example presented in this Guidebook represents a positioning control system that is significantly out of tune. As a result, the airflow damper position was adjusted during the tuning process to allow the proper control to be reestablished. This reflects a common condition in boiler tune-up activities. In most of these instances nothing remains constant as the boiler transitions from as-found to post tune-up. It is common for a given jackshaft position that fuel flow changes, steam flow changes, and airflow changes.

It should be noted that the example in this Guidebook has been simplified for presentation purposes resulting in some of the parameters remaining constant. In fact, this section presents the indirect efficiency evaluation in two stages to introduce the complexity of real-world analyses. The first stage of the presentation is an idealized single operating point analysis with constant steam production. The second stage introduces a simple mechanism that will allow the real-world variations to be incorporated into the analysis.

At this point the general analysis procedure is presented. In any of the analyses the total steam produced during the period of the analysis must be the same. This requirement is true for the indirect efficiency analysis outlined her and for any other type of analysis used (direct fuel measurement, for example). The analysis outlined here is designed to identify the amount of fuel required to provide a constant amount of steam input energy in the as-found and post tune-up conditions. The tune-up process will simply allow the boiler to supply the same amount of steam with less fuel consumption. It is assumed in the analysis that the boiler will operate with constant feedwater properties, steam properties, and blowdown requirements. Therefore, for the analysis, the steam flow and energy added to the steam remain constant. Energy input to the steam ($\dot{E}_{steam}$) is defined by the following equation.

$$\dot{E}_{steam} = \dot{m}_{steam}\left(h_{steam} - h_{fw}\right)$$

Equation 9

The steam and feedwater properties (h_{steam}, h_{fw}) required are the enthalpies of steam and feedwater, respectively. Enthalpy values are commonly obtained by field measurements of fluid temperature and pressure. The field measurements are used in conjunction with thermo-physical property databases to identify the enthalpy values [10], [11], [12]. The mass flow rate of steam ($\dot{m}_{steam}$) is the other factor in the analysis.

As pointed out previously in *Equation 1*, fuel energy input to the boiler is related to steam energy through the definition of boiler efficiency. The fuel input energy ($\dot{E}_{fuel}$) is simply fuel mass flow rate multiplied by the fuel Higher Heating Value ($\dot{m}_{fuel}HHV_{fuel}$). *Equation 1* can be solved for the fuel input energy. When boiler efficiency is known along with the energy added to the steam then the fuel input energy can be calculated rather than measuring fuel input energy directly. This can be a useful tool as will be shown in the following analysis description.

$$\dot{E}_{fuel} = \frac{\dot{m}_{steam}\left(h_{steam} - h_{fw}\right)}{\eta_{boiler}}$$

Equation 10

In this simplified example the boiler efficiency is improved by reducing stack loss while the steam production rate remains constant. The *change in fuel input energy* (χ in Equation 11) is simply the difference in the as-found fuel consumption and the post tune-up fuel consumption. However as shown in

Equation 10 the fuel input energy can be expressed in terms of *boiler efficiency* and *energy added to the steam*.

$$\chi = \dot{E}_{fuel\ initial} - \dot{E}_{fuel\ final}$$

$$\chi = \frac{\dot{E}_{steam}}{\eta_{initial}} - \frac{\dot{E}_{steam}}{\eta_{final}}$$

Equation 11

Recall, in this simplified example the energy added to the steam remains constant. As a result, this equation can be rearranged to provide a more useful form.

$$\chi = \frac{\eta_i}{\eta_i}\frac{\dot{E}_{steam}}{\eta_i} - \frac{\eta_i}{\eta_i}\frac{\dot{E}_{steam}}{\eta_f}$$

$$\chi = \frac{\dot{E}_{steam}}{\eta_i}\left(\frac{\eta_i}{\eta_i} - \frac{\eta_i}{\eta_f}\right)$$

$$\chi = \dot{E}_{fuel\ \ initial}\left(1 - \frac{\eta_i}{\eta_f}\right)$$

Equation 12

Boiler efficiency can be estimated by using the stack loss evaluated from boiler tune-up measurements as identified in *Equation 2*. In this simplified analysis only the stack loss (λ_{stack}) is considered. As a result, boiler efficiency is estimated by simply considering the stack loss.

$$\eta_{estimate} = 100\% - \lambda_{stack} - \underbrace{\lambda_{blowdown} - \lambda_{shell} - \lambda_{auxiliary} - \lambda_{misc}}_{considered\ \ negligible}$$

$$\eta_{estimate} = 100\% - \lambda_{stack}$$

Equation 13

The other losses identified in the equation can be considered if they are properly evaluated, which will improve the accuracy of the evaluation. It should be remembered that the stack loss is the dominant loss for most boiler operations—typically an order-of-magnitude greater than the other individual losses.

The *change in operating cost* (σ in *Equation 14*) is merely the difference in the initial operating cost ($\dot{K}_{initial}$) and the final operating cost ($\dot{K}_{final}$). Where the operating cost is simply the *fuel input energy* multiplied by the *fuel unit cost* (κ_{fuel}).

$$\sigma = \dot{\mathrm{K}}_{initial} - \dot{\mathrm{K}}_{final}$$

$$\sigma = \dot{E}_{fuel\ initial}\,\kappa_{fuel} - \dot{E}_{fuel\ final}\,\kappa_{fuel}$$

$$\sigma = \frac{\dot{E}_{steam}}{\eta_i}\kappa_{fuel} - \frac{\dot{E}_{steam}}{\eta_f}\kappa_{fuel}$$

Equation 14

This equation can be rearranged like the fuel input energy impact equation (*Equation 12*) to provide a more useful form.

$$\sigma = \frac{\eta_i}{\eta_i}\frac{\dot{E}_{steam}}{\eta_i}\kappa_{fuel} - \frac{\eta_i}{\eta_i}\frac{\dot{E}_{steam}}{\eta_f}\kappa_{fuel}$$

$$\sigma = \frac{\dot{E}_{steam}}{\eta_i}\kappa_{fuel}\left(\frac{\eta_i}{\eta_i} - \frac{\eta_i}{\eta_f}\right)$$

$$\sigma = \dot{\mathrm{K}}_{initial}\left(1 - \frac{\eta_i}{\eta_f}\right)$$

Equation 15

This simplified example can be thought of as a boiler operating continuously at only one firing position (high-fire, for example). Further simplifying the example, the boiler produces the same steam flow rate for the post tune-up condition as it did in the as-found condition. These are obvious simplifications to allow the calculation methodology to be presented in a clear manner. The complexities of the real-world will be introduced later in this example. This simplified operating condition experiences a tune-up and the following initial and adjusted conditions result.

Fuel:		Typical Natural Gas	
Flue Gas Oxygen Measurement:		Dry Basis	
Fuel Atomization:		Not Required	
Data	**Units**	**As-Found Single-Position Condition**	**Post Tune-Up Single-Position Condition**
Flue Gas Oxygen (Dry basis)	[%]	9.1	3.6
Final Flue Gas Temp	[°F]	450	450
Ambient Temperature	[°F]	70	70
Flue Gas Combustibles	[ppm]	1	2
Fuel P to Control Valve	[in of water]	50	50
Fuel P to Burner	[in of water]	26.8	24.1
Atomizing Pressure	[psig]	Not required	Not required
Fuel Temperature	[°F]	70	70
Steam Pressure	[psig]	125	125
Steam Temperature	[°F]	353	353
Steam Flow	[lbm/hr]	25,500	25,500
Fuel Flow	[lbm/hr]	1,400	1,350
Windbox Pressure	[in of water]	12.5	12.5
Flame Notes		Blue center-yellow tips	Agitated blue
Flue Gas NOx	[ppm]	6	8
Flue Gas Oxygen (Wet Basis)	[%]	8.0	3.0

Table 7 – Example Operating Data

The data above can be used along with *Table 8 – Stack Loss Table for Natural Gas* to estimate boiler efficiency. Specifically, flue gas oxygen content, flue gas combustibles concentration, flue gas temperature, and ambient temperature are used to obtain the stack loss information. In this example the combustibles concentrations are very low and do not contribute measurably to boiler efficiency. As a result, the combustibles concentrations are considered negligible.

Stack Loss Table for			**Typical Natural Gas**											
Flue Gas Oxygen Content Wet Basis [%]	**Flue Gas Oxygen Content Dry Basis [%]**	**Comb Con [ppm]**	**Stack Loss [% of fuel Higher Heating Value input]**											
			Net Stack Temperature [Δ°F] **{Difference between flue gas exhaust temperature and ambient temperature}**											
			180	**205**	**230**	**255**	**280**	**305**	**330**	**355**	**380**	**405**	**430**	**455**
1.0	1.2	0	13.6	14.1	14.7	15.2	15.8	16.3	16.9	17.4	18.0	18.5	19.1	19.6
2.0	2.4	0	13.8	14.3	14.9	15.5	16.1	16.6	17.2	17.8	18.4	18.9	19.5	20.1
3.0	3.6	0	14.0	14.6	15.2	15.8	16.4	17.0	17.6	18.2	18.8	19.4	20.0	20.6
4.0	4.7	0	14.2	14.8	15.5	16.1	16.7	17.4	18.0	18.7	19.3	20.0	20.6	21.2
5.0	5.8	0	14.5	15.1	15.8	16.5	17.2	17.8	18.5	19.2	19.9	20.5	21.2	21.9
6.0	6.9	0	14.8	15.5	16.2	16.9	17.6	18.3	19.1	19.8	20.5	21.2	22.0	22.7
7.0	8.0	0	15.1	15.9	16.6	17.4	18.1	18.9	19.7	20.5	21.2	22.0	22.8	23.6
8.0	9.1	0	15.5	16.3	17.1	17.9	18.8	19.6	20.4	21.2	22.1	22.9	23.7	24.6
9.0	10.1	0	16.0	16.8	17.7	18.6	19.5	20.4	21.2	22.1	23.0	23.9	24.8	25.7
10.0	11.1	0	16.5	17.4	18.4	19.4	20.3	21.3	22.2	23.2	24.2	25.2	26.1	27.1
Actual Exhaust T [°F]			**250**	**275**	**300**	**325**	**350**	**375**	**400**	**425**	**450**	**475**	**500**	**525**
Ambient T [°F]			**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**

Table 8 – Stack Loss Table for Natural Gas

The stack loss table indicates the initial operating conditions exhibit a 22.1% stack loss and the adjusted operating conditions exhibit an 18.8% stack loss. The initial fuel consumption is 1,400 lbm/hr (based on the fuel flow meter). The example boiler efficiency estimate calculations follow.

$$\eta_{initial \quad condition \quad estimate} = 100\% - \lambda_{stack}$$

$$\eta_i = 100\% - 22.1\% = 77.9\%$$

Equation 16

$$\eta_{final\,condition\,estimate} = 100\% - \lambda_{stack}$$

$$\eta_f = 100\% - 18.8\% = 81.2\%$$

Equation 17

Following the establishment of the boiler efficiency impact estimates**,** the fuel energy impact estimate can be developed. First, the initial fuel input energy is determined. Natural gas is the fuel consumed in the boiler. Laboratory information indicates the fuel Higher Heating Value is 23,311 Btu/lbm.

$$\dot{E}_{fuel} = \dot{m}_{fuel}\, HHV_{fuel}$$

$$\dot{E}_{fuel} = 1{,}400\,\tfrac{lbm}{hr}\left(23{,}311\,\tfrac{Btu}{lbm}\right)$$

$$\dot{E}_{fuel} = 32{,}635{,}400\,\tfrac{Btu}{hr}$$

Equation 18

This basic information allows the fuel impact to be estimated. The calculations are straightforward and as is shown below the fuel impact can be significant.

$$\chi = \dot{E}_{fuel\ initial}\left(1 - \frac{\eta_i}{\eta_f}\right)$$

$$\chi = 32{,}635{,}400\,\tfrac{Btu}{hr}\left(1 - \frac{77.9\%}{81.2\%}\right)$$

$$\chi = 1{,}326{,}300\,\tfrac{Btu}{hr}$$

Equation 19

Generally the economic implication of the tune-up activity is very important because it represents the savings associated with the tune-up effort. The economic impact can be determined through a similar calculation as the fuel energy impact above. Alternately, the economic impact can be determined by multiplying the fuel energy impact by the fuel unit cost. In this example the natural gas unit cost is $\$5.00/10^6$Btu. This results in the following fuel cost impact.

$$\sigma = \chi\ \kappa_{fuel}$$

$$\sigma = 1{,}326{,}300\,\tfrac{Btu}{hr}\left(5.00\,\frac{\$}{10^6\,Btu}\right)$$

$$\sigma = 6.63\,\tfrac{\$}{hr}$$

Equation 20

If the boiler were to operate continuously under these conditions then the impact could be evaluated on an annual basis. Continuous operation implies 24 hr/dy, 365 dy/yr. This results in a fuel purchase impact as indicated below.

$$\sigma = 6.63 \tfrac{\$}{hr} \left(8{,}760 \tfrac{hr}{yr}\right)$$

$$\sigma = 58{,}000 \tfrac{\$}{yr}$$

Equation 21

In this example the efficiency of the boiler improved; but, the steam output energy remained constant. In other words, the boiler continues to produce the same amount of steam with the same properties throughout the operational adjustments. In many direct measurement investigations this condition is not satisfied. As an example it may be desired to measure the performance improvement of a boiler tune-up activity by comparing fuel flow meter measurements. In order to complete an accurate comparison the boiler will have to be operated at constant steam production or an alternate analysis technique will be required. It is extremely difficult to maintain constant steam production for each firing position and the precision of the fuel and steam measurements may not result in acceptable accuracy. The indirect analysis method presented here can be accomplished with minimal instrumentation, it measures the critical efficiency impact parameters, and provides repeatable results. Furthermore simple analysis techniques can be employed to appropriately account for the variations in steam production as the tune-up process continues.

It is interesting to note that in the above simplified single operating point, constant steam production example the analysis could be completed using the fuel flow measurements if the fuel flow meter had sufficient precision and accuracy. However, recall this is a simplified example where the steam production is constant—this will normally not be the case in the real-world. Additionally, in this example the fuel flow measurement has a precision of ±25 lbm/hr. The actual variation in fuel flow from as-found to post tune-up is 57 lbm/hr. As a result, it is easy to identify that using the variation in fuel flow measurement to express the energy savings can be problematic. On the other hand, it should also be noted that more accurate and precise fuel flow measurement can provide excellent impact analysis.

In a real-world analysis a boiler will have a full-range of operating points—typically not just one operating point as was portrayed in the above example. This example has only identified one operating point for simplicity. In order to properly analyze the impact of a boiler tune-up the full range of operating conditions must be considered. It is good to note that often estimates of the impact are desired rather than detailed analyses. Usually what is desired is an accurate indication of the impact the tune-up activity. An excellent analysis method to accomplish this type of evaluation is noted as a *bin analysis*. A *bin analysis* is a simple analysis approach that assumes the boiler operates at several discrete points. Each operating point is analyzed individually identifying the impact observed for that particular condition.

In this type of analysis an estimate of the amount of time the boiler operates at each operating condition must be determined. This is a daunting challenge if significant precision is desired. However, in most instances a general estimate is desired. If this is the case then it is relatively straightforward to develop an estimate of the operating periods of the boiler (that is, the fractions of time the boiler operates at different loads). Some basic observations over time can identify the general operating characteristics of the boiler. If increased precision is desired, then the observation period should be increased or alternate methods should be employed.

The example introduced above is extended here to identify the application of a bin analysis in a typical boiler situation. Initially it was assumed that the boiler operated continuously at one operating point (full-load). The example is now modified to assume the boiler initially operates 40% of the time at the full-load condition (the point identified above) and the remainder of the time (60%) at minimum-load.

It is acknowledged that this two-position example remains highly simplified—the intent is to identify the analysis procedure.

The full-load tune-up conditions are previously provided (*Table 7 – Example Operating Data*) but have been reproduced below along with the minimum-load operating data. It is common for boilers with positioning control to operate at three positions (high-fire, low-fire, and off). This example mimics operating in this manner. However, the analysis easily extends to full modulation control where the boiler operates at any firing position from low-fire through high-fire.

Fuel:		Typical Natural Gas			
Flue Gas Oxygen Measurement:		Dry Basis			
Fuel Atomization:		Not Required			
Data	**Units**	**As-Found High-Fire Condition**	**Adjusted High-Fire Condition**	**As-Found Low-Fire Condition**	**Adjusted Low-Fire Condition**
Flue Gas Oxygen (Dry Basis)	[%]	9.1	3.6	6.9	5.8
Final Flue Gas Temp	[°F]	450	450	350	350
Ambient Temperature	[°F]	70	70	70	70
Flue Gas Combustibles	[ppm]	1	2	5	2
Fuel P to Control Valve	[in of water]	50	50	50	50
Fuel P to Burner	[in of water]	26.8	24.1	2.3	2.3
Atomizing Pressure	[psig]	Not required	Not required	Not required	Not required
Fuel Temperature	[°F]	70	70	70	70
Steam Pressure	[psig]	125	125	125	125
Steam Temperature	[°F]	353	353	353	353
Steam Flow	[lbm/hr]	25,500	25,500	8,100	8,100
Fuel Flow	[lbm/hr]	1,400	1,350	400	400
Windbox Pressure	[in of water]	12.5	12.5	0.5	0.5
Flame Notes		Blue center-yellow tips	Agitated blue	Blue center-yellow tips	Agitated blue
Flue Gas NOx	[ppm]	6	8	3	5
Flue Gas Oxygen (Dry Basis)	[%]	8.0	3.0	6.0	5.0

Table 9 – Example Operating Data

Again the stack loss table is used to estimate boiler efficiency. The combustibles concentrations represented by these measurements are very low and do not contribute measurably to boiler efficiency. As a result, the combustibles concentrations are considered negligible.

Stack Loss Table for			Typical Natural Gas											
Flue Gas Oxygen Content Wet Basis	Flue Gas Oxygen Content Dry Basis	Comb Con	Stack Loss [% of fuel Higher Heating Value input]											
			Net Stack Temperature [Δ°F] {Difference between flue gas exhaust temperature and ambient temperature}											
[%]	[%]	[ppm]	180	205	230	255	280	305	330	355	380	405	430	455
1.0	1.2	0	13.6	14.1	14.7	15.2	15.8	16.3	16.9	17.4	18.0	18.5	19.1	19.6
2.0	2.4	0	13.8	14.3	14.9	15.5	16.1	16.6	17.2	17.8	18.4	18.9	19.5	20.1
3.0	3.6	0	14.0	14.6	15.2	15.8	16.4	17.0	17.6	18.2	18.8	19.4	20.0	20.6
4.0	4.7	0	14.2	14.8	15.5	16.1	16.7	17.4	18.0	18.7	19.3	20.0	20.6	21.2
5.0	5.8	0	14.5	15.1	15.8	16.5	17.2	17.8	18.5	19.2	19.9	20.5	21.2	21.9
6.0	6.9	0	14.8	15.5	16.2	16.9	17.6	18.3	19.1	19.8	20.5	21.2	22.0	22.7
7.0	8.0	0	15.1	15.9	16.6	17.4	18.1	18.9	19.7	20.5	21.2	22.0	22.8	23.6
8.0	9.1	0	15.5	16.3	17.1	17.9	18.8	19.6	20.4	21.2	22.1	22.9	23.7	24.6
9.0	10.1	0	16.0	16.8	17.7	18.6	19.5	20.4	21.2	22.1	23.0	23.9	24.8	25.7
10.0	11.1	0	16.5	17.4	18.4	19.4	20.3	21.3	22.2	23.2	24.2	25.2	26.1	27.1
Actual Exhaust T [°F]			**250**	**275**	**300**	**325**	**350**	**375**	**400**	**425**	**450**	**475**	**500**	**525**
Ambient T [°F]			**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**

Table 10 – Stack Loss Table for Natural Gas

The stack loss table indicates that the low-fire initial operating conditions exhibit a 17.6% stack loss and the low-fire adjusted operating conditions exhibit a 17.2% stack loss. The initial fuel consumption is 400 lbm/hr. The example boiler low-fire efficiency estimate calculations follow.

$$\eta_{initial\ condition\ estimate} = 100\% - \lambda_{stack}$$

$$\eta_{i} = 100\% - 17.61\% = 82.4\%$$

Equation 22

$$\eta_{adjusted\ condition\ estimate} = 100\% - \lambda_{stack}$$

$$\eta_{f} = 100\% - 17.2\% = 82.8\%$$

Equation 23

Next the low-fire initial fuel input energy is determined. Natural gas property data has been identified previously.

$$\dot{E}_{fuel} = \dot{m}_{fuel}\, HHV_{fuel}$$

$$\dot{E}_{fuel} = 400\,\tfrac{lbm}{hr}\left(23{,}311\tfrac{Btu}{lbm}\right)$$

$$\dot{E}_{fuel} = 9{,}324{,}400\,\tfrac{Btu}{hr}$$

Equation 24

The change in fuel consumption is now estimated. This is the fuel input energy impact.

$$\chi = \dot{E}_{fuel\ initial}\left(1-\frac{\eta_i}{\eta_f}\right)$$

$$\chi = 9{,}324{,}400\,\tfrac{Btu}{hr}\left(1-\frac{82.4\%}{82.8\%}\right)$$

$$\chi = 45{,}000\,\tfrac{Btu}{hr}$$

Equation 25

Again the economic impact is determined to allow the cost effectiveness of the tune-up process to be identified. Recall, in this example the natural gas unit cost is \$5.00/10^6Btu. This results in the following fuel cost impact (σ).

$$\sigma = \chi\ \kappa_{fuel}$$

$$\sigma = 45{,}000\,\tfrac{Btu}{hr}\left(5.00\,\frac{\$}{10^6\,Btu}\right)$$

$$\sigma = 0.23\,\tfrac{\$}{hr}$$

Equation 26

The economic impact of this tune-up procedure is minimal at the low-fire condition the principal savings results from the high-fire condition. Application of the bin analysis technique allows an accurate reflection of the overall impact of the tune-up activity. For this simplified analysis it is assumed the operating conditions are representative of 24 hr/dy, 365 dy/yr service. Typically, a real-world analysis will be divided into more discrete periods of time; such as, month long periods. But, this simplified example has the boiler operating 40% of the time (3,504 hr/yr) at high-fire and 60% of the time (5,256 hr/yr) at low-fire.

$$\sigma_{total} = \sigma_{high-fire} + \sigma_{low-fire}$$

$$\sigma_{total} = \underbrace{6.63\,\tfrac{\$}{hr}\left(3{,}504\,\tfrac{hr}{yr}\right)}_{high-fire\ bin} + \underbrace{0.23\,\tfrac{\$}{hr}\left(5{,}256\,\tfrac{hr}{yr}\right)}_{low-fire\ bin}$$

$$\sigma_{total} = 23{,}200\,\tfrac{\$}{yr} + 1{,}200\,\tfrac{\$}{yr}$$

$$\sigma_{total} = 24{,}400\,\tfrac{\$}{yr}$$

Equation 27

As a result, the tune-up of this example boiler will reduce fuel expenditures approximately $24,000/yr—if the combustion control remains at the tuned values. Periodic flue gas measurements can be used to identify the effectiveness of the tune-up process, the need for additional tune-up activities, and the potential to upgrade to automatic trim control.

Many boilers operate with modulation control that allows the combustion controller to proportionally manage the fuel input to the boiler. This type of control will allow the boiler to operate in any firing position from low-fire to high-fire. The bin analysis provides a straightforward analysis technique that allows an accurate representation of the boiler tune-up activity to be determined. A main point to keep in mind when completing any tune-up analysis is that the post tune-up operation must provide the same amount of steam energy to the system that the as-found operation provided.

It is important to note that many boilers operate without fuel flow measurement instrumentation. When fuel flow is not measured, estimates can be obtained for the impact of a boiler tune-up. The estimates will be less accurate than evaluations carried out with fuel flow measurement; however, the estimates can be beneficial and representative of the true impact on boiler operation.

When a boiler is equipped with an accurate steam flow measurement or a feedwater flow measurement the accuracy of the analysis can be excellent. Steam production along with boiler efficiency are used in conjunction to estimate the fuel input energy (*Equation 10*). In the absence of fuel flow measurement and steam flow measurement the accuracy of the analysis declines significantly. However, estimates can be based on the burner rating—it must be emphasized that this results in a only a rough estimate being obtained. But it should be noted that the boiler efficiency information, based on stack loss measurements, can be accurately evaluated with minimal instrumentation. These facts render the indirect efficiency evaluation technique coupled with the bin analysis a valuable tool in evaluating boiler operations.

6) Environmental Impacts

As is noted in *Equation 8* even a very simple fuel will release a wide variety of emissions when combusted. The exhaust gases discharged from a boiler are primarily composed of several components including nitrogen (N_2), carbon dioxide (CO_2), water (H_2O), and oxygen (O_2). The intent of the combustion control arrangement is to minimize excess oxygen while maintaining minimal unburned fuel and mitigating environmental impact. It is the intent of this section of the Guidebook to simply raise awareness of the emissions issues that are connected to a boiler tune-up and to highlight those factors that are not influenced by a boiler tune-up. It is not the intent of this section to provide any in-depth discussions on emissions or emissions controls.

Fuel components such as carbon monoxide (CO) and hydrogen (H_2) almost always represent a small concentration of the boiler exhaust. However, the impact of even small concentrations of un-reacted fuel can be significant. The amount of un-reacted fuel is measured with flue gas analysis equipment as noted in the *Boiler Combustion Tune-Up* section of this Guidebook. Un-reacted fuel is managed through the combustion control activities on which this Guidebook has focused and the internal condition of the burner. This section of the Guidebook focuses on the other environmental impact components; such as, nitrogen oxides, sulfur oxides, and carbon dioxide.

These exhaust components are commonly noted as carbon dioxide (CO_2), sulfur oxides (SOx), nitrogen oxides (NOx), and particulate emissions. When considering the amount of these components being discharged from a boiler burning a hydrocarbon fuel, the mass of carbon dioxide discharged is two orders-of-magnitude (100 times) more than the mass of these other components (SO_x and NO_x). Only nitrogen (N_2), water (H_2O), and oxygen (O_2) are in the same mass flow discharge ranges as carbon dioxide. However, it must be noted that the impact of even small concentrations of these other pollutants (SO_x and NO_x) can produce significant impact.

First, consider carbon dioxide (CO_2), which is a direct result of the chemical composition of the fuel. Carbon dioxide is a greenhouse gas and is coming under greater scrutiny. The combustion process has essentially no impact on the amount of carbon dioxide discharged into the environment. The most important factors dictating carbon dioxide emissions are the fuel composition and the boiler efficiency. The mass discharge of carbon dioxide is directly proportional to the mass flow rate of fuel. The carbon contained in the fuel will convert to carbon dioxide and unburned fuel. The concentration of unburned fuel (primarily CO) will impact the amount of carbon dioxide released; however, even very high concentrations of unburned fuel negligibly impact carbon dioxide emissions. This is not in any way intended to diminish the importance of combustibles management—it is a vital concern. The only point here is that the mass of unburned fuel has a minimal influence on the mass of carbon dioxide released. Therefore, the dominant methods used to influence the amount of carbon dioxide discharged from boiler operations focus on fuel switching and improving boiler efficiency. It is easily identified that for a single fuel if boiler efficiency is improved then carbon dioxide emissions will decrease for a given steam production. Simply stated, less carbon into the boiler will result in less carbon dioxide discharged from the boiler.

Changing fuel obviously can have a significant impact on carbon dioxide emissions. As an example, natural gas may have 42% less carbon than a specific coal. The coal-fired boiler will most probably operate with a higher efficiency than the natural gas fired boiler. The resulting impact may be that switching from coal to natural gas will reduce carbon dioxide emissions by 38%. In the general industrial and commercial arenas there are no other technologies available to address carbon dioxide emissions at the present. The point to consider for this Guidebook is that a boiler tune-up will impact boiler efficiency, which will influence carbon dioxide emissions by changing the amount of fuel required to produce a specific amount of steam.

Sulfur oxides (SOx) are also a direct result of the chemical composition of the fuel. Sulfur is a fuel that reacts similarly to carbon, combusting to form sulfur dioxide (SO_2) or sulfur trioxide (SO_3). These chemicals react with water to form sulfurous acid and sulfuric acid. Sulfur dioxide typically is the primary compound formed. Sulfur oxides are pollutants that contribute to acid rain and other detrimental environmental impacts. Sulfur oxides are managed through three activities—boiler efficiency, fuel selection, and sequestration.

The first two methods mentioned above (boiler efficiency and fuel selection) result in the same type of impacts as were discussed concerning carbon dioxide. Improving boiler efficiency directly impacts the amount of sulfur oxides discharged. Changing the fuel to a fuel that contains less sulfur is a primary sulfur control mechanism. Sulfur is typically a significant component of coals and heavy fuel oils. These can contain more than 1% (mass basis) sulfur—up to $5\%_{\text{mass}}$. Light fuel oils typically contain sulfur; but, usually in lower concentrations (less than $1\%_{\text{mass}}$). Commercially available natural gas generally contains only trace amounts of sulfur compounds.

Sequestering sulfur compounds allows fuels with elevated sulfur content to be burned while the environmental impact is mitigated. Sequestration of sulfur compounds can take place in the combustion arena or downstream of the boiler. Fluid-bed boilers incorporate limestone or other solid components in the combustion zone to react with sulfur compounds. The product chemicals are solids that can be removed as a portion of the fluid-bed material.

Flue gas desulfurization is the process of capturing sulfur compounds downstream of the boiler. Commonly limestone or other chemical is used to react with the sulfur compounds to form a liquid or solid compound that can be removed from the flue gas.

Typically, sulfur is not a significant participant in natural gas and light fuel oil combustion. Similar to the note introduced for carbon dioxide, the point to consider with respect to a boiler tune-up is that an impact on boiler efficiency will influence sulfur emissions.

The emissions components introduced to this point are impacted by a boiler tune-up from the standpoint that an improvement in boiler efficiency will reduce the input of the component in question. For these components reducing the fuel flow reduces the output of the offending compound. The formation of nitrogen oxides somewhat follows this characteristic; however, their formation is very dependent on the characteristics of the combustion process as well. Therefore, a boiler tune-up can significantly influence the output of nitrogen oxides. Nitrogen oxides (NOx) emissions are very dependent on many factors including combustion characteristics. Predicting these impacts and the output of nitrogen oxides is extremely challenging.

Nitrogen oxides are a significant contributor to acid rain pollution and several other environmental impacts. Nitrogen oxides emissions are controlled in many boiler operations. The primary nitrogen oxides components are nitric oxide (NO) and nitrogen dioxide (NO_2). There are additional nitrogen components that contribute to nitrogen oxides emissions; but, they are typically of minimal concentration. It is interesting to note that typically while in the boiler the nitric oxide (NO) species dominates. However, when released into the environment nitric oxide combines with oxygen to form nitrogen dioxide (NO_2). Nitrogen dioxide is a reddish-brown gas harmful in many environmental respects.

It is generally accepted that there are three primary mechanisms responsible for the formation of nitrogen oxides. The first mechanism is identified as *fuel related*, the second is identified as *thermal related*, and the third is identified as *chemical kinetics related*.

Fuels contain nitrogen in various forms. During the combustion reaction the fuel borne nitrogen (Fuel Bound Nitrogen) can experience several reactions with the end result being the formation of nitrogen oxides. The dominant mechanism contributing to the formation of nitrogen oxides from fuel related nitrogen is not significantly impacted by temperature. The main factor impacting nitrogen oxide formation from nitrogen in the fuel is the oxygen concentration in the flame zone (especially in the early stages of combustion). As a result, staged combustion and Flue Gas Recirculation (FGR) are effective measures used to control this pollutant formation mechanism.

Commercially available natural gas contains nitrogen; however, the nitrogen component of natural gas is similar to the nitrogen component of air. This nitrogen is not chemically bound to the fuel it is simply another component entering the combustion zone. The nitrogen contained in commercially available natural gas is not bound in the organic molecules of the fuel; it is essentially an independent molecule. As a result, the fuel related mechanism of forming nitrogen oxides is typically a minor factor for natural gas. Coal and oil; however, present significant amounts of nitrogen oxides from fuel related factors.

The thermal related nitrogen oxides formation mechanism results primarily from the nitrogen entering the combustion zone with the combustion air. Recall, ambient air is typically composed of 21% oxygen and 79% nitrogen. This airborne nitrogen increases temperature as it passes through the combustion zone. The N_2 molecule can gain enough energy in the combustion zone to disassociate into free nitrogen atoms. These atoms react with oxygen atoms that have also disassociated to form nitric oxide and other nitrogen compounds.

The formation of nitrogen oxides from this thermal related mechanism is based primarily on the temperature of the materials in the combustion zone. As a result, staged combustion and flue gas recirculation are effective measures used to control thermal NOx production also.

An additional aspect of nitrogen oxides formation is identified as *prompt NOx*. Nitrogen oxides formation associated with chemical kinetics is a result of many chemical reaction paths that all occur very quickly—thus, this mechanism is often referred to as *prompt NOx*. The chemical reaction paths all include the combination of nitrogen, oxygen, and hydrocarbons (fuels). The reactions become significant in fuel-rich combustion arenas (and lower temperature combustion zones).

The primary point to consider with respect to nitrogen oxides production is that the temperature and oxygen concentration in the combustion zone influence the production of nitrogen oxides. A boiler tune-up activity will influence the temperature and oxygen content of the combustion zone. As a result, nitrogen oxides emissions should be considered during a boiler tune-up activity.

Particulate emissions can be a major point of concern for boiler operations. However, it should be noted that natural gas and light fuel oil combustion typically produces negligible amounts of particulate emissions. Particulate matter discharged with boiler exhaust gas arise primarily from non-combustible solid materials contained in the fuel. Coal contains earth minerals commonly known as ash, which is a major source of particulate matter. Fuel oils also contain ash in some quantity; however, the amount is generally small. Heavy fuel oil will typically incorporate more ash than light fuel oil; but, the ash content of most fuel oil is less than $1\%_{mass}$. The ash content of most coal is greater than $5\%_{mass}$ and can be more than $30\%_{mass}$. Natural gas (commercially available) will have negligible concentrations of particulate matter in the fuel.

Particulate emissions can arise from poor combustion as well. Incomplete combustion of a hydrocarbon fuel can result in soot formation. Soot is typically a small solid (sometimes liquid) carbon containing material. As a result, even natural gas can produce particulate emissions—but, a natural gas fired boiler must be experiencing significant combustion problems if it is producing soot. Improving the combustion process is generally the appropriate control mechanism to reduce soot formation. In oil fired boilers improving the combustion characteristics may involve improving the atomization of the fuel. A boiler tune-up can impact particulate emissions; however, it is from this very poor combustion (fuel-rich) scenario that it arises.

Particulate emissions are generally controlled through flue gas treatment activities. The most common actions involve filtering the particulate matter from the exhaust gas. The two dominant forms of particulate removal are classic filtration and electrostatic precipitation. Classic filtration utilizes a filter media that allows gases to pass but traps solid particles. Electrostatic precipitators allow the particulate laden exhaust gases to pass between electrically charged electrodes. The particles become electrically charged and adhere to the oppositely charged electrode.

7) Reference Material

7.1 Natural Gas Data

Stack Loss Table for			**Typical Natural Gas**											
Flue Gas Oxygen Content Wet Basis [%]	**Flue Gas Oxygen Content Dry Basis [%]**	**Comb Con [ppm]**	**Stack Loss [% of fuel Higher Heating Value input]**											
			Net Stack Temperature [Δ°F] {Difference between flue gas exhaust temperature and ambient temperature}											
			180	**205**	**230**	**255**	**280**	**305**	**330**	**355**	**380**	**405**	**430**	**455**
1.0	1.2	0	13.6	14.1	14.7	15.2	15.8	16.3	16.9	17.4	18.0	18.5	19.1	19.6
2.0	2.4	0	13.8	14.3	14.9	15.5	16.1	16.6	17.2	17.8	18.4	18.9	19.5	20.1
3.0	3.6	0	14.0	14.6	15.2	15.8	16.4	17.0	17.6	18.2	18.8	19.4	20.0	20.6
4.0	4.7	0	14.2	14.8	15.5	16.1	16.7	17.4	18.0	18.7	19.3	20.0	20.6	21.2
5.0	5.8	0	14.5	15.1	15.8	16.5	17.2	17.8	18.5	19.2	19.9	20.5	21.2	21.9
6.0	6.9	0	14.8	15.5	16.2	16.9	17.6	18.3	19.1	19.8	20.5	21.2	22.0	22.7
7.0	8.0	0	15.1	15.9	16.6	17.4	18.1	18.9	19.7	20.5	21.2	22.0	22.8	23.6
8.0	9.1	0	15.5	16.3	17.1	17.9	18.8	19.6	20.4	21.2	22.1	22.9	23.7	24.6
9.0	10.1	0	16.0	16.8	17.7	18.6	19.5	20.4	21.2	22.1	23.0	23.9	24.8	25.7
10.0	11.1	0	16.5	17.4	18.4	19.4	20.3	21.3	22.2	23.2	24.2	25.2	26.1	27.1
Actual Exhaust T [°F]			**250**	**275**	**300**	**325**	**350**	**375**	**400**	**425**	**450**	**475**	**500**	**525**
Ambient T [°F]			**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**

Component	**Mole Fraction [$lbmol_i/lbmol_{fuel}$]**	**Mass Fraction [lbm_i/lbm_{fuel}]**	**Molecular Weight [lbm/lbmol]**
C	0.0000	0.0000	12.000
H_2	0.0000	0.0000	2.016
CH_4	0.9490	0.9053	16.043
N_2	0.0110	0.0183	28.013
CO	0.0000	0.0000	28.011
C_2H_4 (Ethylene)	0.0000	0.0000	28.054
C_2H_6 (Ethane)	0.0340	0.0607	30.020
C_3H_8 (Propane)	0.0060	0.0157	44.097
O_2	0.0000	0.0000	31.999
S	0.0000	0.0000	32.060
H_2O (intrinsic)	0.0000	0.0000	18.015
H_2O (extrinsic)	0.0000	0.0000	18.015
CO_2	0.0000	0.0000	44.010
$C_6H_{10}O_5$ (Cellulose)	0.0000	0.0000	162.140
Ash (Total)	0.0000	0.0000	
Ash Component - Al_2O_3	0.0000	0.0000	101.961
Ash Component - SiO_2	0.0000	0.0000	60.085
Ash Component - Fe_2O_3	0.0000	0.0000	159.692
Total	1.0000	1.0000	
Fuel Molecular Weight	16.8182	$lbm_{fuel}/lbmol_{fuel}$	
Fuel Higher Heating Value	23,311	Btu/lbm	

7.2 Number 2 Fuel Oil (Light Fuel Oil) Data

Stack Loss Table for			**Number 2 Fuel Oil**											
Flue Gas Oxygen Content Wet Basis	**Flue Gas Oxygen Content Dry Basis**	**Comb Con**	**Stack Loss [% of fuel Higher Heating Value input]**											
			Net Stack Temperature [Δ°F] {Difference between flue gas exhaust temperature and ambient temperature}											
[%]	**[%]**	**[ppm]**	**180**	**205**	**230**	**255**	**280**	**305**	**330**	**355**	**380**	**405**	**430**	**455**
1.0	1.1	0	9.5	10.0	10.5	11.0	11.5	12.1	12.6	13.1	13.7	14.2	14.7	15.3
2.0	2.2	0	9.6	10.2	10.7	11.3	11.8	12.4	12.9	13.5	14.1	14.6	15.2	15.7
3.0	3.3	0	9.8	10.4	11.0	11.6	12.1	12.7	13.3	13.9	14.5	15.1	15.7	16.3
4.0	4.4	0	10.1	10.7	11.3	11.9	12.5	13.1	13.7	14.3	15.0	15.6	16.2	16.8
5.0	5.5	0	10.3	10.9	11.6	12.2	12.9	13.5	14.2	14.8	15.5	16.2	16.8	17.5
6.0	6.5	0	10.6	11.3	12.0	12.6	13.3	14.0	14.7	15.4	16.1	16.8	17.5	18.2
7.0	7.6	0	10.9	11.6	12.4	13.1	13.8	14.6	15.3	16.1	16.8	17.5	18.3	19.0
8.0	8.6	0	11.3	12.1	12.8	13.6	14.4	15.2	16.0	16.8	17.6	18.4	19.2	20.0
9.0	9.6	0	11.7	12.6	13.4	14.3	15.1	16.0	16.8	17.7	18.5	19.4	20.3	21.1
10.0	10.6	0	12.2	13.1	14.1	15.0	15.9	16.8	17.8	18.7	19.6	20.6	21.5	22.5
Actual Exhaust T [°F]			**250**	**275**	**300**	**325**	**350**	**375**	**400**	**425**	**450**	**475**	**500**	**525**
Ambient T [°F]			**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**

Component	**Mole Fraction [$lbmol_i/lbmol_{fuel}$]**	**Mass Fraction [lbm_i/lbm_{fuel}]**	**Molecular Weight [lbm/lbmol]**
C	0.5432	0.8562	12.000
H_2	0.4524	0.1198	2.016
CH_4	0.0000	0.0000	16.043
N_2	0.0014	0.0050	28.013
CO	0.0000	0.0000	28.011
C_2H_4 (Ethylene)	0.0000	0.0000	28.054
C_2H_6 (Ethane)	0.0000	0.0000	30.020
C_3H_8 (Propane)	0.0000	0.0000	44.097
O_2	0.0014	0.0060	31.999
S	0.0008	0.0035	32.060
H_2O (intrinsic)	0.0000	0.0000	18.015
H_2O (extrinsic)	0.0000	0.0000	18.015
CO_2	0.0000	0.0000	44.010
$C_6H_{10}O_5$ (Cellulose)	0.0000	0.0000	162.140
Ash (Total)	0.0008	0.0095	
Ash Component - Al_2O_3	0.0001	0.0020	101.961
Ash Component - SiO_2	0.0005	0.0042	60.085
Ash Component - Fe_2O_3	0.0002	0.0033	159.692
Total	1.0000	1.0000	
Fuel Molecular Weight	7.6127	$lbm_{fuel}/lbmol_{fuel}$	
Fuel Higher Heating Value	19,400	Btu/lbm	

7.3 Number 6 Fuel Oil (Heavy Fuel Oil) Data

Stack Loss Table for			Number 6 Fuel Oil											
Flue Gas Oxygen Content Wet Basis	**Flue Gas Oxygen Content Dry Basis**	**Comb Con**	**Stack Loss [% of fuel Higher Heating Value input]**											
			Net Stack Temperature [Δ°F] {Difference between flue gas exhaust temperature and ambient temperature}											
[%]	**[%]**	**[ppm]**	**205**	**230**	**255**	**280**	**305**	**330**	**355**	**380**	**405**	**430**	**455**	**480**
1.0	1.1	0	9.3	9.8	10.4	10.9	11.4	12.0	12.5	13.0	13.6	14.1	14.7	15.2
2.0	2.2	0	9.5	10.1	10.6	11.2	11.7	12.3	12.9	13.4	14.0	14.6	15.1	15.7
3.0	3.3	0	9.8	10.3	10.9	11.5	12.1	12.7	13.3	13.9	14.5	15.1	15.7	16.3
4.0	4.4	0	10.0	10.6	11.2	11.9	12.5	13.1	13.7	14.3	15.0	15.6	16.2	16.9
5.0	5.4	0	10.3	10.9	11.6	12.2	12.9	13.6	14.2	14.9	15.6	16.2	16.9	17.6
6.0	6.5	0	10.6	11.3	12.0	12.7	13.4	14.1	14.8	15.5	16.2	16.9	17.6	18.3
7.0	7.5	0	11.0	11.7	12.5	13.2	14.0	14.7	15.4	16.2	17.0	17.7	18.5	19.2
8.0	8.5	0	11.4	12.2	13.0	13.8	14.6	15.4	16.2	17.0	17.8	18.6	19.4	20.3
9.0	9.6	0	11.9	12.8	13.6	14.5	15.3	16.2	17.1	18.0	18.8	19.7	20.6	21.5
10.0	10.6	0	12.5	13.4	14.4	15.3	16.2	17.2	18.1	19.1	20.0	21.0	21.9	22.9
Actual Exhaust T [°F]			**275**	**300**	**325**	**350**	**375**	**400**	**425**	**450**	**475**	**500**	**525**	**550**
Ambient T [°F]			**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**

Component	**Mole Fraction [$lbmol_i/lbmol_{fuel}$]**	**Mass Fraction [lbm_i/lbm_{fuel}]**	**Molecular Weight [lbm/lbmol]**
C	0.5901	0.8700	12.000
H_2	0.4037	0.1000	2.016
CH_4	0.0000	0.0000	16.043
N_2	0.0015	0.0050	28.013
CO	0.0000	0.0000	28.011
C_2H_4 (Ethylene)	0.0000	0.0000	28.054
C_2H_6 (Ethane)	0.0000	0.0000	30.020
C_3H_8 (Propane)	0.0000	0.0000	44.097
O_2	0.0013	0.0050	31.999
S	0.0025	0.0100	32.060
H_2O (intrinsic)	0.0000	0.0000	18.015
H_2O (extrinsic)	0.0000	0.0000	18.015
CO_2	0.0000	0.0000	44.010
$C_6H_{10}O_5$ (Cellulose)	0.0000	0.0000	162.140
Ash (Total)	0.0009	0.0100	
Ash Component - Al_2O_3	0.0002	0.0021	101.961
Ash Component - SiO_2	0.0006	0.0044	60.085
Ash Component - Fe_2O_3	0.0002	0.0035	159.692
Total	1.0000	1.0000	
Fuel Molecular Weight	8.1390	$lbm_{fuel}/lbmol_{fuel}$	
Fuel Higher Heating Value	18,413	Btu/lbm	

7.4 Coal (5% Water, 5% Ash) Data

Stack Loss Table for			**Coal (5% Water, 5% Ash)**											
Flue Gas Oxygen Content Wet Basis	**Flue Gas Oxygen Content Dry Basis**	**Comb Con**	**Stack Loss [% of fuel Higher Heating Value input]**											
			Net Stack Temperature [Δ°F] {Difference between flue gas exhaust temperature and ambient temperature}											
[%]	**[%]**	**[ppm]**	**230**	**255**	**280**	**305**	**330**	**355**	**380**	**405**	**430**	**455**	**480**	**505**
1.0	1.1	0	8.6	9.2	9.7	10.2	10.8	11.3	11.9	12.4	13.0	13.5	14.1	14.6
2.0	2.1	0	8.9	9.4	10.0	10.6	11.1	11.7	12.3	12.8	13.4	14.0	14.6	15.2
3.0	3.2	0	9.1	9.7	10.3	10.9	11.5	12.1	12.7	13.3	13.9	14.5	15.1	15.7
4.0	4.3	0	9.4	10.0	10.7	11.3	11.9	12.6	13.2	13.8	14.5	15.1	15.8	16.4
5.0	5.3	0	9.7	10.4	11.1	11.7	12.4	13.1	13.7	14.4	15.1	15.8	16.4	17.1
6.0	6.3	0	10.1	10.8	11.5	12.2	12.9	13.6	14.3	15.1	15.8	16.5	17.2	18.0
7.0	7.4	0	10.5	11.3	12.0	12.8	13.5	14.3	15.1	15.8	16.6	17.4	18.1	18.9
8.0	8.4	0	11.0	11.8	12.6	13.4	14.2	15.1	15.9	16.7	17.5	18.3	19.2	20.0
9.0	9.4	0	11.6	12.4	13.3	14.2	15.1	15.9	16.8	17.7	18.6	19.5	20.4	21.3
10.0	10.4	0	12.2	13.2	14.1	15.1	16.0	17.0	17.9	18.9	19.9	20.8	21.8	22.8
Actual Exhaust T [°F]			**300**	**325**	**350**	**375**	**400**	**425**	**450**	**475**	**500**	**525**	**550**	**575**
Ambient T [°F]			**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**

Component	**Mole Fraction [$lbmol_i/lbmol_{fuel}$]**	**Mass Fraction [lbm_i/lbm_{fuel}]**	**Molecular Weight [lbm/lbmol]**
C	0.6658	0.7500	12.000
H_2	0.2642	0.0500	2.016
CH_4	0.0000	0.0000	16.043
N_2	0.0076	0.0200	28.013
CO	0.0000	0.0000	28.011
C_2H_4 (Ethylene)	0.0000	0.0000	28.054
C_2H_6 (Ethane)	0.0000	0.0000	30.020
C_3H_8 (Propane)	0.0000	0.0000	44.097
O_2	0.0233	0.0700	31.999
S	0.0033	0.0100	32.060
H_2O (intrinsic)	0.0296	0.0500	18.015
H_2O (extrinsic)	0.0000	0.0000	18.015
CO_2	0.0000	0.0000	44.010
$C_6H_{10}O_5$ (Cellulose)	0.0000	0.0000	162.140
Ash (Total)	0.0062	0.0500	
Ash Component - Al_2O_3	0.0011	0.0105	101.961
Ash Component - SiO_2	0.0039	0.0220	60.085
Ash Component - Fe_2O_3	0.0012	0.0175	159.692
Total	1.0000	1.0000	
Fuel Molecular Weight	10.6531	$lbm_{fuel}/lbmol_{fuel}$	
Fuel Higher Heating Value	13,670	Btu/lbm	

7.5 Coal (5% Water, 10% Ash) Data

Stack Loss Table for			Coal (5% Water, 10% Ash)											
Flue Gas Oxygen Content Wet Basis	**Flue Gas Oxygen Content Dry Basis**	**Comb Con**	**Stack Loss [% of fuel Higher Heating Value input]**											
			Net Stack Temperature [Δ°F] **{Difference between flue gas exhaust temperature and ambient temperature}**											
[%]	**[%]**	**[ppm]**	**230**	**255**	**280**	**305**	**330**	**355**	**380**	**405**	**430**	**455**	**480**	**505**
1.0	1.1	0	8.8	9.4	9.9	10.5	11.0	11.5	12.1	12.6	13.2	13.7	14.3	14.9
2.0	2.2	0	9.1	9.6	10.2	10.8	11.3	11.9	12.5	13.1	13.6	14.2	14.8	15.4
3.0	3.2	0	9.3	9.9	10.5	11.1	11.7	12.3	12.9	13.5	14.1	14.7	15.3	16.0
4.0	4.3	0	9.6	10.2	10.9	11.5	12.1	12.8	13.4	14.0	14.7	15.3	16.0	16.6
5.0	5.3	0	9.9	10.6	11.3	11.9	12.6	13.3	13.9	14.6	15.3	16.0	16.7	17.3
6.0	6.4	0	10.3	11.0	11.7	12.4	13.1	13.8	14.6	15.3	16.0	16.7	17.4	18.2
7.0	7.4	0	10.7	11.5	12.2	13.0	13.7	14.5	15.3	16.0	16.8	17.6	18.3	19.1
8.0	8.4	0	11.2	12.0	12.8	13.6	14.4	15.3	16.1	16.9	17.7	18.5	19.4	20.2
9.0	9.4	0	11.8	12.6	13.5	14.4	15.3	16.1	17.0	17.9	18.8	19.7	20.6	21.5
10.0	10.4	0	12.4	13.4	14.3	15.3	16.2	17.2	18.1	19.1	20.1	21.0	22.0	23.0
Actual Exhaust T [°F]			**300**	**325**	**350**	**375**	**400**	**425**	**450**	**475**	**500**	**525**	**550**	**575**
Ambient T [°F]			**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**

Component	**Mole Fraction** [lbmol$_i$/lbmol$_{fuel}$]	**Mass Fraction** [lbm$_i$/lbm$_{fuel}$]	**Molecular Weight** [lbm/lbmol]
C	0.6461	0.7000	12.000
H_2	0.2747	0.0500	2.016
CH_4	0.0000	0.0000	16.043
N_2	0.0079	0.0200	28.013
CO	0.0000	0.0000	28.011
C_2H_4 (Ethylene)	0.0000	0.0000	28.054
C_2H_6 (Ethane)	0.0000	0.0000	30.020
C_3H_8 (Propane)	0.0000	0.0000	44.097
O_2	0.0242	0.0700	31.999
S	0.0035	0.0100	32.060
H_2O (intrinsic)	0.0307	0.0500	18.015
H_2O (extrinsic)	0.0000	0.0000	18.015
CO_2	0.0000	0.0000	44.010
$C_6H_{10}O_5$ (Cellulose)	0.0000	0.0000	162.140
Ash (Total)	0.0128	0.1000	
Ash Component - Al_2O_3	0.0023	0.0210	101.961
Ash Component - SiO_2	0.0081	0.0440	60.085
Ash Component - Fe_2O_3	0.0024	0.0350	159.692
Total	1.0000	1.0000	
Fuel Molecular Weight	11.0765	lbm$_{fuel}$/lbmol$_{fuel}$	
Fuel Higher Heating Value	12,965	Btu/lbm	
Fuel Higher Heating Value	18,413	Btu/lbm	

7.6 Coal (5% Water, 15% Ash) Data

Stack Loss Table for			**Coal (5% Water, 15% Ash)**											
Flue Gas Oxygen Content Wet Basis [%]	**Flue Gas Oxygen Content Dry Basis [%]**	**Comb Con [ppm]**	**Stack Loss [% of fuel Higher Heating Value input]**											
			Net Stack Temperature [Δ°F] {Difference between flue gas exhaust temperature and ambient temperature}											
			230	**255**	**280**	**305**	**330**	**355**	**380**	**405**	**430**	**455**	**480**	**505**
1.0	1.1	0	9.1	9.6	10.2	10.7	11.2	11.8	12.3	12.9	13.4	14.0	14.5	15.1
2.0	2.2	0	9.3	9.9	10.4	11.0	11.6	12.1	12.7	13.3	13.9	14.5	15.0	15.6
3.0	3.2	0	9.6	10.2	10.8	11.3	11.9	12.6	13.2	13.8	14.4	15.0	15.6	16.2
4.0	4.3	0	9.8	10.5	11.1	11.7	12.4	13.0	13.6	14.3	14.9	15.6	16.2	16.8
5.0	5.3	0	10.2	10.8	11.5	12.2	12.8	13.5	14.2	14.9	15.5	16.2	16.9	17.6
6.0	6.4	0	10.5	11.2	11.9	12.7	13.4	14.1	14.8	15.5	16.2	16.9	17.7	18.4
7.0	7.4	0	11.0	11.7	12.5	13.2	14.0	14.7	15.5	16.3	17.0	17.8	18.6	19.3
8.0	8.4	0	11.4	12.2	13.1	13.9	14.7	15.5	16.3	17.1	17.9	18.8	19.6	20.4
9.0	9.5	0	12.0	12.9	13.7	14.6	15.5	16.4	17.2	18.1	19.0	19.9	20.8	21.7
10.0	10.5	0	12.7	13.6	14.6	15.5	16.5	17.4	18.4	19.3	20.3	21.2	22.2	23.2
Actual Exhaust T [°F]			**300**	**325**	**350**	**375**	**400**	**425**	**450**	**475**	**500**	**525**	**550**	**575**
Ambient T [°F]			**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**

Component	**Mole Fraction [lbmol$_i$/lbmol$_{fuel}$]**	**Mass Fraction [lbm$_i$/lbm$_{fuel}$]**	**Molecular Weight [lbm/lbmol]**
C	0.6248	0.6500	12.000
H_2	0.2861	0.0500	2.016
CH_4	0.0000	0.0000	16.043
N_2	0.0082	0.0200	28.013
CO	0.0000	0.0000	28.011
C_2H_4 (Ethylene)	0.0000	0.0000	28.054
C_2H_6 (Ethane)	0.0000	0.0000	30.020
C_3H_8 (Propane)	0.0000	0.0000	44.097
O_2	0.0252	0.0700	31.999
S	0.0036	0.0100	32.060
H_2O (intrinsic)	0.0320	0.0500	18.015
H_2O (extrinsic)	0.0000	0.0000	18.015
CO_2	0.0000	0.0000	44.010
$C_6H_{10}O_5$ (Cellulose)	0.0000	0.0000	162.140
Ash (Total)	0.0200	0.1500	
Ash Component - Al_2O_3	0.0036	0.0315	101.961
Ash Component - SiO_2	0.0127	0.0660	60.085
Ash Component - Fe_2O_3	0.0038	0.0525	159.692
Total	1.0000	1.0000	
Fuel Molecular Weight	11.5349	lbm$_{fuel}$/lbmol$_{fuel}$	
Fuel Higher Heating Value	12,260	Btu/lbm	

7.7 Coal (5% Water, 20% Ash) Data

Stack Loss Table for			**Coal (5% Water, 20% Ash)**											
Flue Gas Oxygen Content Wet Basis [%]	**Flue Gas Oxygen Content Dry Basis [%]**	**Comb Con [ppm]**	**Stack Loss [% of fuel Higher Heating Value input]**											
			Net Stack Temperature [Δ°F] {Difference between flue gas exhaust temperature and ambient temperature}											
			230	**255**	**280**	**305**	**330**	**355**	**380**	**405**	**430**	**455**	**480**	**505**
1.0	1.1	0	9.3	9.9	10.4	11.0	11.5	12.1	12.6	13.2	13.7	14.3	14.8	15.4
2.0	2.2	0	9.6	10.1	10.7	11.3	11.8	12.4	13.0	13.6	14.1	14.7	15.3	15.9
3.0	3.3	0	9.8	10.4	11.0	11.6	12.2	12.8	13.4	14.0	14.6	15.2	15.9	16.5
4.0	4.3	0	10.1	10.7	11.4	12.0	12.6	13.3	13.9	14.5	15.2	15.8	16.5	17.1
5.0	5.4	0	10.4	11.1	11.8	12.4	13.1	13.8	14.4	15.1	15.8	16.5	17.2	17.8
6.0	6.4	0	10.8	11.5	12.2	12.9	13.6	14.3	15.1	15.8	16.5	17.2	17.9	18.7
7.0	7.4	0	11.2	12.0	12.7	13.5	14.2	15.0	15.8	16.5	17.3	18.1	18.8	19.6
8.0	8.5	0	11.7	12.5	13.3	14.1	14.9	15.7	16.6	17.4	18.2	19.0	19.8	20.7
9.0	9.5	0	12.3	13.1	14.0	14.9	15.7	16.6	17.5	18.4	19.3	20.2	21.0	21.9
10.0	10.5	0	12.9	13.9	14.8	15.8	16.7	17.7	18.6	19.6	20.5	21.5	22.5	23.4
Actual Exhaust T [°F]			**300**	**325**	**350**	**375**	**400**	**425**	**450**	**475**	**500**	**525**	**550**	**575**
Ambient T [°F]			**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**

Component	**Mole Fraction [lbmol$_i$/lbmol$_{fuel}$]**	**Mass Fraction [lbm$_i$/lbm$_{fuel}$]**	**Molecular Weight [lbm/lbmol]**
C	0.6016	0.6000	12.000
H_2	0.2984	0.0500	2.016
CH_4	0.0000	0.0000	16.043
N_2	0.0086	0.0200	28.013
CO	0.0000	0.0000	28.011
C_2H_4 (Ethylene)	0.0000	0.0000	28.054
C_2H_6 (Ethane)	0.0000	0.0000	30.020
C_3H_8 (Propane)	0.0000	0.0000	44.097
O_2	0.0263	0.0700	31.999
S	0.0038	0.0100	32.060
H_2O (intrinsic)	0.0334	0.0500	18.015
H_2O (extrinsic)	0.0000	0.0000	18.015
CO_2	0.0000	0.0000	44.010
$C_6H_{10}O_5$ (Cellulose)	0.0000	0.0000	162.140
Ash (Total)	0.0279	0.2000	
Ash Component - Al_2O_3	0.0050	0.0420	101.961
Ash Component - SiO_2	0.0176	0.0880	60.085
Ash Component - Fe_2O_3	0.0053	0.0700	159.692
Total	1.0000	1.0000	
Fuel Molecular Weight	12.0329	lbm$_{fuel}$/lbmol$_{fuel}$	
Fuel Higher Heating Value	11,554	Btu/lbm	

7.8 Coal (5% Water, 25% Ash) Data

Stack Loss Table for			**Coal (5% Water, 25% Ash)**											
Flue Gas Oxygen Content Wet Basis	**Flue Gas Oxygen Content Dry Basis**	**Comb Con**	**Stack Loss [% of fuel Higher Heating Value input]**											
			Net Stack Temperature [Δ°F] {Difference between flue gas exhaust temperature and ambient temperature}											
[%]	**[%]**	**[ppm]**	**230**	**255**	**280**	**305**	**330**	**355**	**380**	**405**	**430**	**455**	**480**	**505**
1.0	1.1	0	9.6	10.2	10.7	11.3	11.8	12.4	12.9	13.5	14.0	14.6	15.1	15.7
2.0	2.2	0	9.9	10.4	11.0	11.6	12.1	12.7	13.3	13.9	14.5	15.0	15.6	16.2
3.0	3.3	0	10.1	10.7	11.3	11.9	12.5	13.1	13.7	14.3	14.9	15.5	16.2	16.8
4.0	4.3	0	10.4	11.0	11.7	12.3	12.9	13.6	14.2	14.8	15.5	16.1	16.8	17.4
5.0	5.4	0	10.7	11.4	12.1	12.7	13.4	14.1	14.7	15.4	16.1	16.8	17.5	18.1
6.0	6.4	0	11.1	11.8	12.5	13.2	13.9	14.6	15.3	16.1	16.8	17.5	18.2	19.0
7.0	7.5	0	11.5	12.3	13.0	13.8	14.5	15.3	16.0	16.8	17.6	18.3	19.1	19.9
8.0	8.5	0	12.0	12.8	13.6	14.4	15.2	16.0	16.8	17.7	18.5	19.3	20.1	21.0
9.0	9.5	0	12.5	13.4	14.3	15.2	16.0	16.9	17.8	18.7	19.6	20.4	21.3	22.2
10.0	10.5	0	13.2	14.1	15.1	16.0	17.0	17.9	18.9	19.8	20.8	21.8	22.7	23.7
Actual Exhaust T [°F]			**300**	**325**	**350**	**375**	**400**	**425**	**450**	**475**	**500**	**525**	**550**	**575**
Ambient T [°F]			**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**

Component	**Mole Fraction** **[$lbmol_i/lbmol_{fuel}$]**	**Mass Fraction** **[lbm_i/lbm_{fuel}]**	**Molecular Weight** **[lbm/lbmol]**
C	0.5764	0.5500	12.000
H_2	0.3119	0.0500	2.016
CH_4	0.0000	0.0000	16.043
N_2	0.0090	0.0200	28.013
CO	0.0000	0.0000	28.011
C_2H_4 (Ethylene)	0.0000	0.0000	28.054
C_2H_6 (Ethane)	0.0000	0.0000	30.020
C_3H_8 (Propane)	0.0000	0.0000	44.097
O_2	0.0275	0.0700	31.999
S	0.0039	0.0100	32.060
H_2O (intrinsic)	0.0349	0.0500	18.015
H_2O (extrinsic)	0.0000	0.0000	18.015
CO_2	0.0000	0.0000	44.010
$C_6H_{10}O_5$ (Cellulose)	0.0000	0.0000	162.140
Ash (Total)	0.0364	0.2500	
Ash Component - Al_2O_3	0.0065	0.0525	101.961
Ash Component - SiO_2	0.0230	0.1100	60.085
Ash Component - Fe_2O_3	0.0069	0.0875	159.692
Total	1.0000	1.0000	
Fuel Molecular Weight	12.5759	$lbm_{fuel}/lbmol_{fuel}$	
Fuel Higher Heating Value	10,849	Btu/lbm	

7.9 Coal (5% Water, 30% Ash) Data

Stack Loss Table for			**Coal (5% Water, 30% Ash)**											
Flue Gas Oxygen Content Wet Basis [%]	**Flue Gas Oxygen Content Dry Basis [%]**	**Comb Con [ppm]**	**Stack Loss [% of fuel Higher Heating Value input]**											
			Net Stack Temperature [Δ°F] {Difference between flue gas exhaust temperature and ambient temperature}											
			230	**255**	**280**	**305**	**330**	**355**	**380**	**405**	**430**	**455**	**480**	**505**
1.0	1.1	0	10.0	10.5	11.1	11.6	12.2	12.7	13.3	13.8	14.4	14.9	15.5	16.0
2.0	2.2	0	10.2	10.8	11.3	11.9	12.5	13.1	13.6	14.2	14.8	15.4	16.0	16.6
3.0	3.3	0	10.5	11.1	11.7	12.3	12.9	13.5	14.1	14.7	15.3	15.9	16.5	17.1
4.0	4.4	0	10.7	11.4	12.0	12.6	13.3	13.9	14.5	15.2	15.8	16.5	17.1	17.8
5.0	5.4	0	11.1	11.7	12.4	13.1	13.7	14.4	15.1	15.8	16.4	17.1	17.8	18.5
6.0	6.5	0	11.4	12.1	12.8	13.5	14.3	15.0	15.7	16.4	17.1	17.8	18.6	19.3
7.0	7.5	0	11.8	12.6	13.3	14.1	14.9	15.6	16.4	17.1	17.9	18.7	19.4	20.2
8.0	8.5	0	12.3	13.1	13.9	14.7	15.5	16.4	17.2	18.0	18.8	19.6	20.5	21.3
9.0	9.6	0	12.9	13.7	14.6	15.5	16.4	17.2	18.1	19.0	19.9	20.8	21.7	22.5
10.0	10.6	0	13.5	14.5	15.4	16.4	17.3	18.3	19.2	20.2	21.1	22.1	23.1	24.0
Actual Exhaust T [°F]			**300**	**325**	**350**	**375**	**400**	**425**	**450**	**475**	**500**	**525**	**550**	**575**
Ambient T [°F]			**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**

Component	**Mole Fraction [$lbmol_i/lbmol_{fuel}$]**	**Mass Fraction [lbm_i/lbm_{fuel}]**	**Molecular Weight [lbm/lbmol]**
C	0.5488	0.5000	12.000
H_2	0.3266	0.0500	2.016
CH_4	0.0000	0.0000	16.043
N_2	0.0094	0.0200	28.013
CO	0.0000	0.0000	28.011
C_2H_4 (Ethylene)	0.0000	0.0000	28.054
C_2H_6 (Ethane)	0.0000	0.0000	30.020
C_3H_8 (Propane)	0.0000	0.0000	44.097
O_2	0.0288	0.0700	31.999
S	0.0041	0.0100	32.060
H_2O (intrinsic)	0.0366	0.0500	18.015
H_2O (extrinsic)	0.0000	0.0000	18.015
CO_2	0.0000	0.0000	44.010
$C_6H_{10}O_5$ (Cellulose)	0.0000	0.0000	162.140
Ash (Total)	0.0457	0.3000	
Ash Component - Al_2O_3	0.0081	0.0630	101.961
Ash Component - SiO_2	0.0289	0.1320	60.085
Ash Component - Fe_2O_3	0.0087	0.1050	159.692
Total	1.0000	1.0000	
Fuel Molecular Weight	13.1701	$lbm_{fuel}/lbmol_{fuel}$	
Fuel Higher Heating Value	10,143	Btu/lbm	

7.10 Coal (10% Water, 5% Ash) Data

Stack Loss Table for			Coal (10% Water, 5% Ash)											
Flue Gas Oxygen Content Wet Basis	Flue Gas Oxygen Content Dry Basis	Comb Con	Stack Loss [% of fuel Higher Heating Value input]											
			Net Stack Temperature [Δ°F] {Difference between flue gas exhaust temperature and ambient temperature}											
[%]	[%]	[ppm]	230	255	280	305	330	355	380	405	430	455	480	505
1.0	1.1	0	9.3	9.8	10.4	10.9	11.4	12.0	12.5	13.1	13.6	14.2	14.8	15.3
2.0	2.2	0	9.5	10.1	10.6	11.2	11.8	12.4	12.9	13.5	14.1	14.7	15.3	15.8
3.0	3.2	0	9.8	10.4	11.0	11.6	12.2	12.8	13.4	14.0	14.6	15.2	15.8	16.4
4.0	4.3	0	10.1	10.7	11.3	11.9	12.6	13.2	13.9	14.5	15.1	15.8	16.4	17.1
5.0	5.4	0	10.4	11.0	11.7	12.4	13.1	13.7	14.4	15.1	15.8	16.4	17.1	17.8
6.0	6.4	0	10.8	11.5	12.2	12.9	13.6	14.3	15.0	15.7	16.5	17.2	17.9	18.7
7.0	7.4	0	11.2	11.9	12.7	13.4	14.2	15.0	15.7	16.5	17.3	18.0	18.8	19.6
8.0	8.5	0	11.7	12.5	13.3	14.1	14.9	15.7	16.6	17.4	18.2	19.0	19.9	20.7
9.0	9.5	0	12.2	13.1	14.0	14.9	15.7	16.6	17.5	18.4	19.3	20.2	21.1	22.0
10.0	10.5	0	12.9	13.9	14.8	15.8	16.7	17.7	18.6	19.6	20.6	21.5	22.5	23.5
Actual Exhaust T [°F]			**300**	**325**	**350**	**375**	**400**	**425**	**450**	**475**	**500**	**525**	**550**	**575**
Ambient T [°F]			**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**

Component	**Mole Fraction** [$lbmol_i/lbmol_{fuel}$]	**Mass Fraction** [lbm_i/lbm_{fuel}]	**Molecular Weight** [lbm/lbmol]
C	0.6308	0.7000	12.000
H_2	0.2682	0.0500	2.016
CH_4	0.0000	0.0000	16.043
N_2	0.0077	0.0200	28.013
CO	0.0000	0.0000	28.011
C_2H_4 (Ethylene)	0.0000	0.0000	28.054
C_2H_6 (Ethane)	0.0000	0.0000	30.020
C_3H_8 (Propane)	0.0000	0.0000	44.097
O_2	0.0237	0.0700	31.999
S	0.0034	0.0100	32.060
H_2O (intrinsic)	0.0600	0.1000	18.015
H_2O (extrinsic)	0.0000	0.0000	18.015
CO_2	0.0000	0.0000	44.010
$C_6H_{10}O_5$ (Cellulose)	0.0000	0.0000	162.140
Ash (Total)	0.0063	0.0500	
Ash Component - Al_2O_3	0.0011	0.0105	101.961
Ash Component - SiO_2	0.0040	0.0220	60.085
Ash Component - Fe_2O_3	0.0012	0.0175	159.692
Total	1.0000	1.0000	
Fuel Molecular Weight	10.8134	$lbm_{fuel}/lbmol_{fuel}$	
Fuel Higher Heating Value	12,965	Btu/lbm	

7.11 Coal (10% Water, 10% Ash) Data

Stack Loss Table for			**Coal (10% Water, 10% Ash)**											
Flue Gas Oxygen Content Wet Basis [%]	**Flue Gas Oxygen Content Dry Basis [%]**	**Comb Con [ppm]**	**Stack Loss [% of fuel Higher Heating Value input]**											
			Net Stack Temperature [Δ°F] {Difference between flue gas exhaust temperature and ambient temperature}											
			230	**255**	**280**	**305**	**330**	**355**	**380**	**405**	**430**	**455**	**480**	**505**
1.0	1.1	0	9.5	10.1	10.6	11.2	11.7	12.3	12.8	13.4	13.9	14.5	15.0	15.6
2.0	2.2	0	9.8	10.3	10.9	11.5	12.0	12.6	13.2	13.8	14.4	14.9	15.5	16.1
3.0	3.3	0	10.0	10.6	11.2	11.8	12.4	13.0	13.6	14.2	14.9	15.5	16.1	16.7
4.0	4.3	0	10.3	10.9	11.6	12.2	12.8	13.5	14.1	14.8	15.4	16.1	16.7	17.4
5.0	5.4	0	10.6	11.3	12.0	12.6	13.3	14.0	14.7	15.3	16.0	16.7	17.4	18.1
6.0	6.4	0	11.0	11.7	12.4	13.1	13.8	14.6	15.3	16.0	16.7	17.5	18.2	18.9
7.0	7.5	0	11.4	12.2	12.9	13.7	14.5	15.2	16.0	16.8	17.5	18.3	19.1	19.9
8.0	8.5	0	11.9	12.7	13.5	14.4	15.2	16.0	16.8	17.6	18.5	19.3	20.1	21.0
9.0	9.5	0	12.5	13.4	14.2	15.1	16.0	16.9	17.8	18.7	19.5	20.4	21.3	22.2
10.0	10.5	0	13.2	14.1	15.1	16.0	17.0	17.9	18.9	19.9	20.8	21.8	22.8	23.7
Actual Exhaust T [°F]			**300**	**325**	**350**	**375**	**400**	**425**	**450**	**475**	**500**	**525**	**550**	**575**
Ambient T [°F]			**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**

Component	**Mole Fraction [$lbmol_i/lbmol_{fuel}$]**	**Mass Fraction [lbm_i/lbm_{fuel}]**	**Molecular Weight [lbm/lbmol]**
C	0.6094	0.6500	12.000
H_2	0.2790	0.0500	2.016
CH_4	0.0000	0.0000	16.043
N_2	0.0080	0.0200	28.013
CO	0.0000	0.0000	28.011
C_2H_4 (Ethylene)	0.0000	0.0000	28.054
C_2H_6 (Ethane)	0.0000	0.0000	30.020
C_3H_8 (Propane)	0.0000	0.0000	44.097
O_2	0.0246	0.0700	31.999
S	0.0035	0.0100	32.060
H_2O (intrinsic)	0.0624	0.1000	18.015
H_2O (extrinsic)	0.0000	0.0000	18.015
CO_2	0.0000	0.0000	44.010
$C_6H_{10}O_5$ (Cellulose)	0.0000	0.0000	162.140
Ash (Total)	0.0130	0.1000	
Ash Component - Al_2O_3	0.0023	0.0210	101.961
Ash Component - SiO_2	0.0082	0.0440	60.085
Ash Component - Fe_2O_3	0.0025	0.0350	159.692
Total	1.0000	1.0000	
Fuel Molecular Weight	11.2499	$lbm_{fuel}/lbmol_{fuel}$	
Fuel Higher Heating Value	12,260	Btu/lbm	

7.12 Green Wood Data

Stack Loss Table for			**Green Wood**											
Flue Gas Oxygen Content Wet Basis	**Flue Gas Oxygen Content Dry Basis**	**Comb Con**	**Stack Loss [% of fuel Higher Heating Value input]**											
			Net Stack Temperature [Δ°F] **{Difference between flue gas exhaust temperature and ambient temperature}**											
[%]	**[%]**	**[ppm]**	**230**	**255**	**280**	**305**	**330**	**355**	**380**	**405**	**430**	**455**	**480**	**505**
1.0	1.4	0	24.9	25.6	26.3	27.0	27.7	28.4	29.2	29.9	30.6	31.3	32.0	32.8
2.0	2.7	0	25.2	25.9	26.7	27.4	28.1	28.9	29.6	30.4	31.2	31.9	32.7	33.4
3.0	4.0	0	25.5	26.3	27.1	27.8	28.6	29.4	30.2	31.0	31.8	32.6	33.4	34.2
4.0	5.2	0	25.9	26.7	27.5	28.3	29.2	30.0	30.8	31.7	32.5	33.3	34.2	35.0
5.0	6.4	0	26.3	27.2	28.0	28.9	29.8	30.6	31.5	32.4	33.3	34.2	35.0	35.9
6.0	7.6	0	26.8	27.7	28.6	29.5	30.4	31.4	32.3	33.2	34.2	35.1	36.1	37.0
7.0	8.7	0	27.3	28.3	29.3	30.2	31.2	32.2	33.2	34.2	35.2	36.2	37.2	38.2
8.0	9.7	0	27.9	29.0	30.0	31.1	32.1	33.2	34.2	35.3	36.4	37.4	38.5	39.6
9.0	10.8	0	28.6	29.8	30.9	32.0	33.2	34.3	35.4	36.6	37.7	38.9	40.1	41.2
10.0	11.8	0	29.5	30.7	31.9	33.2	34.4	35.6	36.9	38.1	39.4	40.6	41.9	43.1
Actual Exhaust T [°F]			**300**	**325**	**350**	**375**	**400**	**425**	**450**	**475**	**500**	**525**	**550**	**575**
Ambient T [°F]			**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**

Component	**Mole Fraction** **[$lbmol_i/lbmol_{fuel}$]**	**Mass Fraction** **[lbm_i/lbm_{fuel}]**	**Molecular Weight** **[lbm/lbmol]**
C	0.1234	0.0500	12.000
H_2	0.0000	0.0000	2.016
CH_4	0.0000	0.0000	16.043
N_2	0.0000	0.0000	28.013
CO	0.0000	0.0000	28.011
C_2H_4 (Ethylene)	0.0000	0.0000	28.054
C_2H_6 (Ethane)	0.0000	0.0000	30.020
C_3H_8 (Propane)	0.0000	0.0000	44.097
O_2	0.0000	0.0000	31.999
S	0.0004	0.0004	32.060
H_2O (intrinsic)	0.7889	0.4800	18.015
H_2O (extrinsic)	0.0000	0.0000	18.015
CO_2	0.0000	0.0000	44.010
$C_6H_{10}O_5$ (Cellulose)	0.0839	0.4596	162.140
Ash (Total)	0.0034	0.0100	
Ash Component - Al_2O_3	0.0006	0.0021	101.961
Ash Component - SiO_2	0.0022	0.0044	60.085
Ash Component - Fe_2O_3	0.0006	0.0035	159.692
Total	1.0000	1.0000	
Fuel Molecular Weight	29.6086	$lbm_{fuel}/lbmol_{fuel}$	
Fuel Higher Heating Value	4,157	Btu/lbm	

8) References

The following is a list of references utilized in boiler tune-up analysis and energy assessments. Some of these references are cited in the text of this report. This list represents excellent sources of technical information.

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