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# Exploring a Variant of PTC 4-2013 for Real-Time Performance Monitoring of Fossil Fuel Power Plants

*This paper describes a real-time performance-monitoring method based on PTC 4-2013 that was developed for determining and reporting the annual heat rate for fossil fuel power plants. Unlike for the PTC 4 test, the coal composition is typically not known in real-time, so the procedure uses a modified output-loss approach applied to a control volume that closely conforms to the boiler. A calibration approach utilizes an ultimate analysis to describe the coal being burned during the calibration, while holding the plant load and other factors steady. This permits the calculation of correction factors used during real-time performance monitoring. Based on several assumptions that are justified within, a real-time estimate of coal composition is obtained. The losses are calculated in a similar manner to PTC 4-2013. However, the losses are expressed on a per-pound of as-fired coal basis, as opposed to a percentage of higher heating value of the coal, which is not known in real-time. [DOI: 10.1115/1.4055467]*

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## Introduction

This paper describes a calculation protocol (based on ASME PTC 4-2013) and real-time performance-monitoring method that was developed for determining and reporting the annual heat rate for fossil fuel power plants. The ASME performance test codes [1] prescribe two methods for determining the boiler efficiency of steam electric generating unit (EGUs), i.e., the input–output method [2] and the loss method [3,4]. The latter is also referred to as the energy balance method. If every step must be followed rigorously in order to determine the boiler efficiency as suggested by the performance test codes, it would be difficult to implement the method in real-time. The tests are therefore conducted on a periodic basis. One of the main disadvantages of the loss method is that the same set of data can yield different values of boiler efficiency [5,6]. Likewise, in many instances, the input–output method does not utilize instantaneous values of the higher heating value. The reason for this occurrence is that different choices are made for items to be included as output, input, and credits, depending on the practices of that utility. It is therefore difficult to compare the performance of one unit to another based on the boiler efficiency value alone. Another drawback of these two methods is that the most important performance parameter, i.e., the unit heat rate, is not addressed.

The most important index to evaluate the performance of an EGU coal-fired power plant is the unit heat rate. This is the ratio of the rate at which energy is supplied to a unit at a given instant to the power generation at that instant. The engineering units for representing the unit heat rate are Btu/kW-hr, which implies that the unit heat rate is a single-valued parameter. However, there are two other performance indices, i.e., the boiler efficiency and the steam cycle heat rate. Under a certain strict set of definitions, the unit heat rate can be expressed as the quotient of the cycle heat rate and the boiler efficiency. Throughout the world, the power industry adopted the practice of calculating the cycle heat rate and the boiler efficiency independently of each other, ignoring the coupling between the two parameters, and then calculating the unit heat rate. The procedure for calculating the steam cycle heat rate appears to follow a universal practice. However, the boiler efficiency, which is calculated by the loss method, is calculated in many different ways, based on the control volume selected for the analysis. The practices for evaluating boiler efficiency differ from one location to another, and even in the same power station, the calculation procedures can vary from unit to unit. Thus, the unit heat rate does not have a single correct value, but has a value that depends on the boiler efficiency calculation method. This is the most serious shortcoming that exists within the power industry throughout the world. A unified method known as the output-loss method exists for determining all three indices, i.e., the boiler efficiency, the steam cycle heat rate, and finally the unit heat rate, consistently and uniquely. This real-time modeling approach will be described in this paper. The procedure will eliminate the current anomalies that exist universally in the area of power plant performance modeling.

The net unit heat rate is determined by measuring the mass flowrate of coal, the higher heating value (HHV) of the coal, and the net power generation [7]. The mass flowrate of coal is measured through weight belt gravimetric feeders [2], the higher heating value is used for calculating the heat rate in the input–output method, and the net power generation is the result of subtracting the auxiliary power from the gross power generation [7]. The HHV is measured in a lab environment [8], which implies the input–output method cannot be used in a real-time performance-monitoring system [9]. In Ref. [4], the tests performed indicated behaviors of varying conditions such as coal size distribution changing the shape of the heat rate versus  $O_2$  curve, air flow distribution and tuning changes for different fuels, differences in kinetic behavior of the coal can have great effects on the heat rate behavior, and optimum levels of  $O_2$  and other parameters. For real-time performance monitoring, a recent paper [10] describes the whole

process models of coal-fired power plants and provides insight into important equations to determine real-time performance monitoring for coal-fired power plants.

The input–output method is a direct way to measure the net unit heat rate. This method uses the direct measurement of the energy input to the boiler and the net electrical output of the power unit [7]. The uncertainties for the input of this method are controlled by the uncertainties in the coal flowrate and HHV [7]. The flowrate uncertainty can be accurate within 1% with proper calibration, but can change over time as the calibration drifts, which causes larger uncertainties well over 1% [7]. Currently, there are no regulations for plant coal scales to be calibrated at certain intervals. The HHV measurements have an uncertainty of more than 1% in laboratory equipment [7]. The uncertainty of the coal fuel flow can vary substantially due to the accuracy and calibration of the feeder scales and can be between 2 and 8%. Per Ref. [1], the total steam generator efficiency uncertainty is normally around 3–6% for the input–output method.

The loss method [5,6] utilizes the concepts of output and losses but therein introduces heat balance energy and energy credits into the overall energy balance. While testing this method, it was concluded that the blow-down heat and auxiliary equipment heat, which previously were considered to be an output and input, respectively, were both losses. The differences between using the U.S. customary HHV and the European customary lower heating value (LHV) have on the steam generator efficiency were also considered [5]. In [5] it was noted that uncertainty analyses had yet to be conducted. However, upon discussions with steam generator test engineers [5], it was contended that most unanimously supported the heat balance method [5]. They noted that on large solid fuel steam generators, the loss data were more accessible than the data the input–output method required. It was concluded that the HHV emphasized the efficient use of all the heat in the fuel and that the increased use of continuous flue gas analyzers (CEMS) has reduced the uncertainty of flue gas loss computations. Furthermore, the loss method costs less for any size or fuel-fired unit compared to the input–output method [5]. In Ref. [6], what was considered an input, output, or loss was clarified. In that instance, the input was defined as the fuel mass flowrate multiplied by the as-fired higher heating value. Similarly, the output was defined as the heat transferred to the steam mass flows, whereas the fuel efficiency was defined as the output divided by the input. It was noted that with the varying steam generator efficiency definitions, some of the terms can be moved between categories [6].

The output-loss method, which is the focus of this paper, is a method that was developed in Refs. [2,3] and was further refined as discussed in Refs. [7,11–16]. This method, when compared to the previously mentioned input–output method and the heat balance method, has fundamental advantages. The calibration algorithm (which is one aspect of the output-loss method) assumes that the coal ultimate analysis, unburned carbon in ash, and the fuel moisture are known quantities; it is discussed subsequently. In that case,  $CO$  and  $O_2$  concentrations measured at the economizer exit are used to derive the balance combustion equation and thus account for losses. On the other hand, the real-time algorithm (CEMS-based method) employs measured  $CO_2$ ,  $CO$ ,  $SO_2$ , and  $O_2$  concentrations in the flue gas; it will likewise be described further below. In addition, the output-loss method utilizes feedwater flowrate, steam temperatures, and pressures entering and leaving the boiler. Then, in conjunction with coal mass flowrate measurements (as well as further simplifying assumptions), the fuel composition is inferred instantaneously, and that information is utilized to evaluate the unit heat rate on a real-time basis.

## Calculations

**Balanced Reaction Equation.** Application of the output-loss method requires that the balanced chemical reaction equation for coal combustion with moist air be known. It is often difficult to

obtain representative samples of coal for analysis because the composition varies from location to location, even within a given coal seam. As a result, there is a limit on the accuracy of coal analyses in assessing combustion in a given application. An ultimate coal analysis is a chemical analysis that provides the elemental weight fractions of carbon, hydrogen, nitrogen, oxygen, and sulfur. The ash content and heating value of the coal may also be provided. The mass of coal is the mass of the ultimate analysis components, plus the masses of fuel moisture and ash, hence

$$m = \sum m_{\text{components}} + m_{\text{ash}} + m_{\text{moisture}} \quad (1)$$

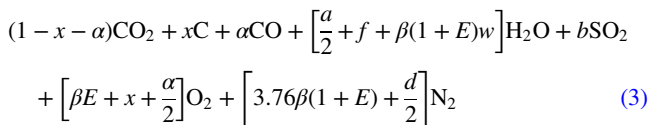
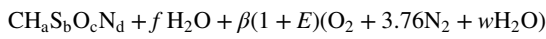
Dividing through by the total mass  $m$  and rearranging yields

$$\frac{\sum m_{\text{components}}}{m} = 1 - A - M \quad (2)$$

where  $A$  is the ash fraction of total coal mass, and  $M$  is the moisture fraction of total coal mass. In this standard where it is pertinent, coal analysis data can be converted to a moisture-ash-free (MAF) basis by using the dimensionless adjustment factor  $MAF = 1 - A - M$ .

In the determination of the air-fuel ratio for the combustion of solid fuels, it is important to account for the ash and moisture in the fuel in the as-fired condition. Thermal modeling of a coal-fired boiler requires the balanced chemical reaction equation for the combustion of coal with moist air. Several assumptions were employed in this study: (i) an excess of air is supplied, (ii) the formation of  $\text{NO}_x$  is disregarded, (iii) the unburned carbon is assumed to be known, and (iv) the composition of coal is known by means of an ultimate analysis; this information is required to calibrate the real-time heat rate algorithm.

Application of the output-loss method requires that the balanced chemical reaction equation for coal combustion with moist air be known, based on ultimate analysis. On a per unit mole of carbon basis, it is expressed as follows:



In Eq. (3), all molar coefficients are expressed per mole of fuel carbon. The following terms are defined:

- (1)  $a$ ,  $b$ ,  $c$ , and  $d$  are the number of moles of each element per mole of fuel carbon
- (2)  $f$  is the number of moles of fuel moisture per mole of fuel carbon
- (3)  $\beta$  is the stoichiometric combustion air molar coefficient per mole of fuel carbon.
- (4)  $E$  is the excess air.
- (5)  $w$  is the number of moles of ambient air moisture per mole of oxygen, available from a psychrometric analysis.
- (6)  $x$  is the number of moles of unburned carbon per mole of fuel carbon in the fly ash.
- (7)  $\alpha$  is the number of moles of carbon monoxide per mole of fuel carbon

The mass of any species  $m_i$  is related to the number of moles  $n_i$  through its molecular weight  $MW_i$  such that

$$m_i = n_i \cdot MW_i \quad (4)$$

In this paper, when the mass of a species “ $i$ ” is expressed on a per unit mole basis it is denoted using the molecular weight terminology, i.e., as  $MW_i$ . Let C, H, S, O, and N denote the weight percentage of 100 pounds of as-fired coal for carbon, hydrogen, sulfur, oxygen, and nitrogen, respectively, as determined by means of ultimate analysis. The number of moles of each fuel element is obtained by dividing the weight of that component (known from the ultimate analysis) by its molecular weight,

thereby yielding the number of moles of that species. Dividing through by the number of moles of carbon, the chemical formula for the moisture and ash-free coal is expressed on a per unit mole of fuel carbon basis. This procedure allows for the determination of the molar coefficients  $a$ ,  $b$ ,  $c$ , and  $d$  in Eq. (3). The stoichiometric combustion air molar coefficient is given by

$$\beta = 1 + \frac{a}{4} + b - \frac{c}{2} \quad (5)$$

In this study, the molecular weight of the MAF coal was evaluated by normalizing the MAF coal mass by the number of moles of carbon in the sample. The apparent molecular weight of the moisture and ash-free coal is evaluated per unit mole of fuel carbon as follows:

$$MW_{MAF} = MW_C + a \cdot MW_H + b \cdot MW_S + c \cdot MW_O + d \cdot MW_N \quad (6)$$

The molecular weight of an as-fired (AF) coal sample is expressed in terms of the moisture and ash-free (MAF) coal molecular weight, such that

$$MW_{AF} = \frac{MW_{MAF}}{MAF} \quad (7)$$

The conversion from a moisture and ash-free basis to an as-fired basis is likewise extended to other considerations in a similar manner. Let “FM” denote the percentage of moisture in the fuel, based on an ultimate analysis. In that case, the moles of fuel moisture (as-fired) per mole of fuel carbon is given by

$$f = \left(\frac{FM/100}{MAF}\right) \cdot \frac{MW_{MAF}}{MW_{\text{H}_2\text{O}}} \quad (8)$$

From measurements of the ambient dry- and wet-bulb temperatures, the humidity ratio is determined from available correlations. The molecular weight of dry air (assumed to be comprised solely of oxygen and nitrogen) was calculated by

$$MW_{\text{dry air}} = \left(\frac{1}{4.76}\right) \cdot MW_{\text{O}_2} + \left(\frac{3.76}{4.76}\right) \cdot MW_{\text{N}_2} \quad (9)$$

The number of moles of water vapor (per unit mole of oxygen) in the balanced reaction equation is expressed in terms of the molecular weights of dry air and water vapor as follows:

$$w = 4.76 \cdot \omega \cdot \left(\frac{MW_{\text{dry air}}}{MW_{\text{H}_2\text{O}}}\right) = \omega \cdot \left[\frac{MW_{\text{O}_2} + 3.76 \cdot MW_{\text{N}_2}}{MW_{\text{H}_2\text{O}}}\right] \quad (10)$$

The ash in the coal is chemically inert and does not participate in the combustion reaction. The unburned carbon is determined by means of a chemical analysis of an ash sample. The ash consists of two quantities: (i) bottom ash which falls as a solid (or molten liquid) to an ash pit located in the bottom of the furnace, and (ii) fly ash particles which are carried along with the product gases and are later removed by electrostatic precipitators or a bag house. Because of the very high temperatures of the bottom ash, it is assumed that all unburned carbon appears only in the fly ash. Let FLYASH denote the fraction of the unburned material resulting from the coal combustion process that is collected in the electrostatic precipitators/baghouse. The loss on ignition (LOI), defined as the measured weight fraction of unburned carbon (UC) in the fly ash, is calculated as follows:

$$\frac{UC}{UC + \text{FLYASH}} = \text{LOI}(\%) \quad (11)$$

The fly ash generally comprises a significant fraction of all the ash generated by coal combustion. The remainder is attributed to bottom ash. Plant personnel can specify the value of FLYASH based on typical operating conditions. It is assumed that all unburned carbon resides in the fly ash, which is relatively cooler than the much warmer bottom ash. That implies the following:

$$\frac{UC}{TOTAL\ ASH + UC} = FLYASH \cdot LOI \quad (12)$$

This is expressed as a weight fraction of unburned carbon to fuel carbon:

$$\frac{UC}{FC} = \frac{FLYASH \cdot LOI}{1 - FLYASH \cdot LOI} \cdot \frac{TOTAL\ ASH}{FC} \quad (13)$$

The left-hand side is also equal to the ratio of the number of moles of unburned carbon to the number of moles of fuel carbon, denoting that quantity as  $x$ . The right-hand side contains the weight ratio of total ash to fuel carbon, which is available from an ultimate analysis of the coal. Hence, the parameter  $x$  is evaluated as follows:

$$x = \frac{FLYASHLOI}{1 - FLYASHLOI} \cdot \frac{TOTAL\ ASH}{FC} \quad (14)$$

**CEMS Data.** The flue gases resulting from coal combustion with air generally include carbon dioxide (CO<sub>2</sub>), water vapor (H<sub>2</sub>O), oxygen (O<sub>2</sub>) nitrogen (N<sub>2</sub>), and such trace gases such as nitrogen oxides (NO<sub>x</sub>), sulfur oxides (SO<sub>x</sub>) and carbon monoxide (CO). In addition, unburned hydrocarbons are often present. Depending on the sampling technique, the flue gas concentration measurements can be performed on either a dry or wet basis. For a dry basis measurement, a significant portion of the water vapor in the flue gases is condensed from the sample prior to analyzing the sample, whereas for a wet basis measurement the water vapor is not removed from the flue gases. The excess air and the CO molar coefficient are calculated in terms of the mole fraction of O<sub>2</sub> and CO as measured at the economizer exit. Referring to Eq. (3), the unburned carbon appears as a solid in the product gases and hence exerts no partial pressure. In that case, the oxygen mole fraction in the product gases expressed on a wet basis is

$$y_{O_2} = \frac{\beta E + x + \frac{\alpha}{2}}{1 - x - \alpha + \alpha + \frac{a}{2} + f + \beta(1 + E)w + b + \beta E + x + \frac{\alpha}{2} + 3.76\beta(1 + E) + \frac{d}{2}} \quad (15)$$

Upon simplifying the denominator and rearranging, this is written as follows:

$$\{\beta[1 - y_{O_2}(4.76 - w)]\}E + \frac{1}{2}(1 - y_{O_2})\alpha = y_{O_2} \left[ 1 + \frac{a}{2} + b + \frac{d}{2} + f + \beta(3.76 + w) \right] - x \quad (16)$$

Likewise, on a wet basis, the carbon monoxide mole fraction in the product gases is given by

$$y_{CO} = \frac{\alpha}{1 - x - \alpha + \alpha + \frac{a}{2} + f + \beta(1 + E)w + b + \beta E + x + \frac{\alpha}{2} + 3.76\beta(1 + E) + \frac{d}{2}} \quad (17)$$

This is rearranged algebraically such that

$$-[y_{CO}\beta(4.76 + w)]E + \left(1 - \frac{y_{CO}}{2}\right)\alpha = y_{CO} \left[ 1 + \frac{a}{2} + b + \frac{d}{2} + f + \beta(3.76 + w) \right] \quad (18)$$

If the oxygen in the product gases is measured on a dry basis, this implies:

$$\{\beta[1 - 4.76y_{O_2}]\}E + \frac{1}{2}(1 - y_{O_2})\alpha = y_{O_2} \left[ 1 + b + \frac{d}{2} + f + 3.76\beta \right] - x \quad (19)$$

Moreover, if the carbon monoxide in the product gases is measured on a dry basis:

$$-[y_{CO}\beta(4.76)]E + \left(1 - \frac{y_{CO}}{2}\right)\alpha = y_{CO} \left[ 1 + b + \frac{d}{2} + f + 3.76\beta \right] \quad (20)$$

Based on measurements of %O<sub>2</sub> and ppm CO in the flue products, the excess air  $E$  and the carbon monoxide molar coefficient  $\alpha$  are determined by simultaneously solving Eqs. (16) and (18) for wet basis CEMS measurements, or Eqs. (19) and (20) for dry basis CEMS measurements.

To evaluate losses associated with the dry air and dry flue gases, as well as losses due to the effects of moisture in the fuel and combustion air, it is noted that the total airflow (dry air plus moisture) enters the boiler in three different streams, i.e., boiler leakage (BLRLK), primary air, and secondary air. Each stream is at a different temperature. The BLRLK is expressed as a percentage of the total airflow. It is a static variable prescribed by plant personnel, based on their operational experience. In the absence of reliable data, a boiler leakage percentage of 1.5 is assumed in this investigation. The remaining 98.5% of the combustion air is apportioned between the primary and secondary air. Hence, considering the balanced chemical reaction expressed in Eq. (3), the total number of moles of O<sub>2</sub> (per mole of C) in the combustion

air is given by

$$n_{O_2, total} = \beta(1 + E) \quad (21)$$

Similarly, the number of total moles of N<sub>2</sub> per mole of C in the combustion air is

$$n_{N_2, total} = 3.76 \cdot \beta(1 + E) \quad (22)$$

Likewise, the total number of moles of H<sub>2</sub>O per mole of C is expressed as

$$n_{H_2O, total} = w \cdot \beta(1 + E) \quad (23)$$

Therein, the number of moles of O<sub>2</sub>, N<sub>2</sub>, and H<sub>2</sub>O in the combustion air attributable to boiler leakage is equal to 0.015 times the amounts defined by Eqs. (21)–(23), respectively. For example

$$n_{O_2, LA} = 0.015 \cdot n_{O_2, total} \quad (24)$$

Analogous expressions are applied to determine the number of moles of nitrogen and water vapor present in the boiler leakage.

The ratio of the mass of primary air to the mass of coal is defined as follows:

$$\text{AIRCOAL} = \frac{m_{PA}}{m_{coal}} \quad (25)$$

This static variable is determined by plant personnel. Referring to Eq. (9), the molecular weight of combustion air per mole of  $O_2$  is defined as follows:

$$MW_{air} = MW_{O_2} + 3.76 \cdot MW_{N_2} + w \cdot MW_{H_2O} \quad (26)$$

In that instance, the number of moles of  $O_2$  in the primary air (per mole of C) is expressed as

$$n_{O_2,PA} = \left( \frac{MW_{AF}}{MW_{air}} \right) \cdot \text{AIRCOAL} \quad (27)$$

Furthermore:

$$n_{N_2,PA} = 3.76 \cdot n_{O_2,PA} \quad (28)$$

The number of moles of  $H_2O$  per mole of C in the primary combustion air is

$$n_{H_2O,PA} = w \cdot n_{O_2,PA} \quad (29)$$

Given knowledge of the number of moles of species associated with the leakage and primary air streams, the number of moles of  $O_2$  per mole of C in the secondary combustion air is evaluated as

$$n_{O_2,SA} = n_{O_2,total} - n_{O_2,LA} - n_{O_2,PA} \quad (30)$$

By similar reasoning, the number of moles of  $N_2$  per mole of C in the secondary combustion air is

$$n_{N_2,SA} = n_{N_2,total} - n_{N_2,LA} - n_{N_2,PA} \quad (31)$$

Furthermore, the moles of  $H_2O$  per mole of C in the secondary combustion air are expressed as

$$n_{H_2O,SA} = n_{H_2O,total} - n_{H_2O,LA} - n_{H_2O,PA} \quad (32)$$

**Output-Loss Method Energy Calculations.** Several indices are used to describe the performance of a coal-fired steam generating unit. For example, boiler efficiency  $\eta_B$  is defined as:

$$\eta_B = \frac{\dot{Q}_{steam}}{\dot{m}_{coal} \cdot \text{HHV}} \quad (33)$$

In this instance  $\dot{Q}_{steam}$  denotes the net measured heat transfer rate to the steam, i.e., it is the useful heat output from the boiler. Per Fig. 1, the steam heat transfer rate can be evaluated in terms of the enthalpy difference associated with the main steam, feed water, and hot and cold reheat mass flowrates. Likewise, the enthalpy of each stream can be determined by measuring the steam pressure and temperature at the inlet and outlet of the superheater and reheater convection passes, respectively. In many instances, it is further necessary to account for tempering sprays or feedwater extractions. The quantity  $\dot{m}_{coal}$  represents the coal mass flowrate, and HHV indicates the coal higher heating value, which is obtained from a calorific analysis of the fuel. In terms of the plant gross generation " $P_{Gross}$ ", the steam cycle heat rate is expressed as

$$\text{HR}_{Cycle} = \frac{\dot{Q}_{steam}}{P_{Gross}} \quad (34)$$

The gross unit heat rate is given by

$$\text{HR}_{Gross} = \frac{\text{HR}_{Cycle}}{\eta_B} = \frac{\dot{m}_{coal} \cdot \text{HHV}}{P_{Gross}} \quad (35)$$

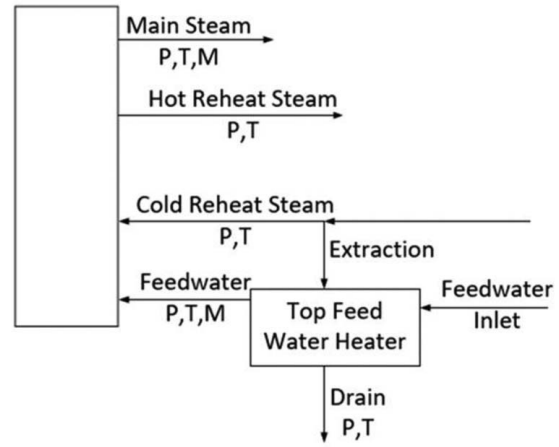


Fig. 1 System modeled by output-loss method [17]

Likewise, the net unit heat rate is evaluated in terms of the station service power "SS" as follows:

$$\text{HR}_{Net} = \frac{\dot{m}_{coal} \cdot \text{HHV}}{P_{Gross} - \text{SS}} = \frac{\text{HR}_C}{\eta_B} \cdot \frac{\text{KW}_{Gross}}{P_{Gross} - \text{SS}} \quad (36)$$

Referring to Fig. 2, a first law energy balance performed on a control volume that surrounds the boiler of a steam EGU is expressed as follows:

$$\text{Input} = \text{Output} + \text{Losses} \quad (37)$$

Alternately this is given by:

$$\dot{m}_{coal} \cdot \text{HHV} = \dot{Q}_{steam} + L_o \quad (38)$$

The quantity " $L_o$ " denotes thermal losses for the system, i.e., the portion of the coal fuel energy that does not contribute to heat transfer to the steam. Equation (38) is reduced to the following form by dividing through by the coal flowrate/higher heating value product

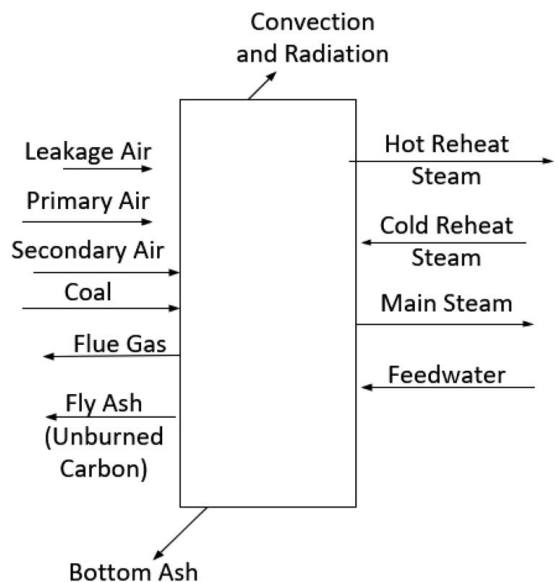


Fig. 2 Control volume boundary with associated inputs and losses [17]



as follows:

$$1 = \frac{\dot{Q}_{steam}}{\dot{m}_{coal} \cdot HHV} + \left( \frac{Lo}{\dot{m}_{coal}} \right) \frac{1}{HHV} \quad (39)$$

Let  $\ell$  denote the losses per unit mass of coal, such that:

$$\ell = \frac{Lo}{\dot{m}_{coal}} \quad (40)$$

Hence, the first law of energy balance on the boiler is evaluated as follows:

$$\eta_B = 1 - \frac{\ell}{HHV} \quad (41)$$

This study utilizes a methodology to evaluate  $\ell$  based on Ref. [1]. The following losses are considered: (i) dry flue gas loss, (ii) moisture in air loss, (iii) fuel moisture loss, (iv), hydrogen burning loss, (v) unburned carbon loss, (vi) formation of CO loss, (vii) fly ash and bottom ash loss, and (viii) surface radiation and convection loss. The losses are evaluated on a per-pound of as-fired coal basis, as opposed to a percentage of HHV of the coal, which is not known in real-time. Complete details regarding the calculation of the losses are provided in Ref. [17].

Consider the control volume boundary surrounding the boiler; once again refer to Fig. 2. Under steady-state conditions, the first law of thermodynamics reduces to

$$\dot{E}_{in} = \dot{E}_{out} \quad (42)$$

Chemical energy is carried into the control volume by coal flow and then is released by combustion in the presence of moist air. The sensible energy of the coal entering the control volume is assumed to be negligible. Sensible energy is conveyed into the control volume by the flow of dry combustion air, as well as due to the moisture present in both the fuel and air. A significant fraction of the fuel energy is used to provide heat to superheat the water flowing through the convection passes of the boiler. Additional energy is transported away from the control volume due to the flow of heated dry flue products, as well as with the fuel and combustion air moisture. Furthermore, sensible energy resulting from the chemical reaction of hydrogen in the fuel is transferred from the control volume, along with the other flue gases. Other flows of energy from the control volume are attributed to ash flow, unburned carbon and carbon monoxide associated with incomplete combustion, and radiation and convection losses to the environment from the exposed surface of the boiler. Substituting the various energy transfer quantities into Eq. (42) and rearranging yields the following:

$$\begin{aligned} \dot{m}_{coal} \cdot HHV = & \dot{Q}_{steam} + [(\dot{E}_{dry\ gases, out} - \dot{E}_{dry\ air, in}) \\ & + (\dot{E}_{H_2O, out} - \dot{E}_{H_2O, in}) + \dot{E}_{ash} + \dot{E}_{unburned\ carbon} + \dot{E}_{CO\ formation} + \dot{Q}_{rad}] \end{aligned} \quad (43)$$

The left-hand side of Eq. (43) denotes the “Input” referred to in Eq. (37), whereas  $\dot{Q}_{steam}$  represents the “Output.” The terms in square brackets indicate the “Losses.” The coal mass flowrate must be known, or it can be solved algebraically. To calculate the losses per unit mass of coal, the balanced chemical reaction equation is first obtained as outlined previously. In Eq. (43), the quantity  $\dot{Q}_{steam}$  denotes the net heat transferred to the steam from the combustion products. Flow rate, pressure, and temperature data for the feed water, main steam, cold reheat steam, and hot reheat steam are needed to calculate the steam heat transfer  $\dot{Q}_{steam}$ . These calculations are performed per PTC 4 (2013) [1].

**Calibration Algorithm.** A first law energy balance on the boiler is expressed as

$$\dot{m}_{coal} \cdot HHV = \dot{Q}_{steam} + \ell \cdot \dot{m}_{coal} \quad (44)$$

The quantities  $\dot{Q}_{steam}$  and  $\ell$  are determined from available plant data, using the methods described previously. There are two unknowns in Eq. (44), i.e., HHV and  $\dot{m}_{coal}$ . Typically the coal HHV is not continuously measured. However, if the coal scales are reliable, Eq. (44) can be utilized to infer an instantaneous fuel higher heating value. Alternately, if accurate historical coal heating value data are available, Eq. (44) can be employed for the determination of the coal mass flowrate. This permits calibration of the coal scales by defining the following coal flow correction factor:

$$\text{CoalFlCorFac} = \frac{\dot{m}_{coal}}{\dot{m}_{coal, plant}} \quad (45)$$

This correction factor is a static variable and is supplied by the calibration algorithm to be used in the real-time algorithm to calculate the actual coal flowrate.

The output-loss method described in this paper employed O<sub>2</sub> and CO concentration measurements (performed on either a wet or dry basis at the economizer exit) to balance the combustion reaction equation. Depending on the particular coal-fired EGU, flue gas concentrations can either be measured immediately downstream of the economizer or downstream of the air preheater. If any gas species concentrations are measured in the air preheater exit, they must be related to their respective values at the exit plane of the economizer. This is due to the air leakage associated with the preheater, which has the effect of diluting the concentrations of flue gases leaving the air preheater. For steady flow, the molar flowrate of any species  $n_i$  normalized by the molar flowrate of fuel carbon  $\dot{n}_C$  can be expressed as follows:

$$\frac{\dot{n}_i}{\dot{n}_C} = \frac{n_i}{n_C} \quad (46)$$

Let “Le” denotes the number of moles of O<sub>2</sub> per mole of C leaking into the air preheater. For every mole of O<sub>2</sub>, 3.76 L moles of N<sub>2</sub> and w·Le moles of water vapor leak into the stack from the air preheater. Performing a molar balance on a rate basis for a control volume surrounding the air preheater yields

$$\begin{aligned} \dot{n}_C [n_{CO_2} + n_{CO} + n_{H_2O} + n_{SO_2} + n_{O_2} + n_{N_2}] \\ + \dot{n}_C \cdot Le [1 + 3.76 + w] = \dot{n}_C [n_{CO_2} + n_{CO} + n_{H_2O} \\ + n_{SO_2} + n_{O_2} + n_{N_2} + Le \{1 + 3.76 + w\}] \end{aligned} \quad (47)$$

The carbon molar flowrate factors are from both sides of the equation. Thus, Eq. (47) is independent of time, and the molar coefficients  $n_i$  (expressed implicitly per mole of fuel carbon) are known from the balanced reaction equation. The right-hand side of Eq. (47) represents the number of moles of the species present at the air preheater exit. For example, if the molar concentrations of CO<sub>2</sub>, SO<sub>2</sub>, etc., are measured on a wet basis, for CO<sub>2</sub> that implies the measured mole fraction  $y_{CO_2}$  can be expressed as

$$y_{CO_2} = \frac{n_{CO_2}}{n_{CO_2} + n_{CO} + n_{H_2O} + n_{SO_2} + n_{O_2} + n_{N_2} + Le(1 + 3.76 + w)} \quad (48)$$

The number of moles of CO<sub>2</sub> in the stack is unaffected by air preheater leakage (APH). Solving for the number of moles of O<sub>2</sub> leaking into the stack flow from the air preheater

$$Le = \frac{\frac{n_{CO_2}}{y_{CO_2}} - (n_{CO_2} + n_{CO} + n_{H_2O} + n_{SO_2} + n_{O_2} + n_{N_2})}{1 + 3.76 + w} \quad (49)$$

The mass of air leaking into the stack from the preheater is calculated as

$$m_{leakage\ air} = Le [MW_{O_2} + 3.76 \cdot MW_{N_2} + w \cdot MW_{H_2O}] \quad (50)$$

By similar reasoning the mass of flue gas present in the stack is expressed as:

$$m_{flue\ gas} = n_{CO_2} \cdot MW_{CO_2} + n_{CO} \cdot MW_{CO} + n_{H_2O} \cdot MW_{H_2O} + n_{SO_2} \cdot MW_{SO_2} + n_{O_2} \cdot MW_{O_2} + n_{N_2} \cdot MW_{N_2} \quad (51)$$

Hence the percent air preheater leakage is given by:

$$APH_{leak} = \frac{m_{leakage\ air}}{m_{flue\ gas}} \times 100 \quad (52)$$

In this investigation,  $APH_{leak}$  is a static variable and is supplied by the calibration algorithm to the real-time algorithm.

Two gas correction factors are calculated in the calibration algorithm to permit the conversion of CEMS concentration data for  $SO_2$  and  $CO_2$  performed at the air preheater exit to their corresponding economizer outlet values. In that instance, the  $CO_2$  correction factor is calculated as

$$CO2CorFac = \frac{y_{CO_2,stack}}{y_{CO_2,econ}} \quad (53)$$

and:

$$SO2CorFac = \frac{y_{SO_2,stack}}{y_{SO_2,econ}} \quad (54)$$

In Eqs. (53) and (54), the mole fractions for  $CO_2$  and  $SO_2$ , respectively, are evaluated using the balanced reaction equation given by Eq. (3). These correction factors are static variables and are supplied by the calibration algorithm to the real-time algorithm.

**Real-Time Algorithm.** The balanced coal combustion equation is given by Eq. (3). If the coal composition is unknown (i.e., when an ultimate analysis is outdated), there are eight unknowns in this expression. These include the molar coefficients  $a$ ,  $b$ ,  $c$ ,  $d$ , and  $f$ , as well as the parameters on the product side such as  $x$ ,  $\alpha$ , and  $E$ . Generally, flue gas concentration data for  $CO_2$ ,  $CO$ ,  $SO_2$ , and  $O_2$  are available from plant CEMS data. This permits only four mass balance expressions. Therefore, to determine the unknown coal composition, several terms in the combustion equation must be approximated, or they can be taken from the most recent available ultimate analysis. This investigation supposes the fuel molar coefficients  $c$  and  $d$  can be obtained from the latest coal analysis. Similarly, it is assumed that the fuel moisture FM, the ash percentage ASH, loss on ignition LOI, and the percentage of total ash attributed to fly ash FLYASH are known. These quantities are supplied to the real-time algorithm by the calibration algorithm and are assumed to be static variables; i.e., their values exhibit little change over time. The fraction of unburned carbon appearing in the total ash is

$$UCTASH = \left( \frac{LOI}{100} \right) \cdot \left( \frac{FLYASH}{100} \right) \quad (55)$$

Likewise, the MAF composition of 100 pounds of coal is expressed as

$$MAF = 100(1 - A - M) \quad (56)$$

Therein, defining the number of carbon moles per unit weight of MAF coal

$$X2 = \left( \frac{UCTASH}{1 - UCTASH} \right) \cdot \left( \frac{ASH}{MW_c \cdot MAF} \right) \quad (57)$$

Define the following fuel moisture parameter, which characterizes the number of moles of water in the fuel per mole of carbon

$$FM2 = \frac{FM}{MAF \cdot MW_{H_2O}} \quad (58)$$

Since the ambient pressure, temperature, and relative are known, there is sufficient information to calculate the ambient air moisture variable “ $w$ ” in Eq. (3).

The methodology employed in this study requires that real-time CEMS molar concentration data for  $CO$  and  $O_2$  are attainable at the economizer exit. It is likewise necessary that similar  $CO_2$  and  $SO_2$  concentration data are available at the preheater exit or before any scrubber units preceding the stack. From the calibration algorithm, the  $CO_2$  and  $SO_2$  correction factors expressed by Eqs. (53) and (54), respectively, are used to evaluate the mole fractions of these species at the economizer exit, i.e.

$$y_{CO_2,econ} = \frac{y_{CO_2,stack}}{CO2CorFac} \quad (59)$$

and:

$$y_{SO_2,econ} = \frac{y_{SO_2,stack}}{SO2CorFac} \quad (60)$$

These measurements may be performed on either a dry or wet basis.

The real-time algorithm utilizes the air preheater term  $APH_{leak}$  provided by the calibration algorithm to evaluate the mass of leakage air as follows:

$$m_{leakage\ air} = \left( \frac{APH_{leak}}{100} \right) \cdot m_{flue\ gas} \quad (61)$$

The number of moles of leakage  $O_2$  (per unit mole of carbon) are calculated as follows:

$$n_{O_2,leak} = \frac{m_{leakage\ air}}{MW_{O_2} + 3.76 \cdot MW_{N_2} + w \cdot MW_{H_2O}} \quad (62)$$

Likewise, the number of moles of leakage  $N_2$  per mole of carbon is evaluated as

$$n_{N_2,leak} = 3.76 \cdot n_{O_2,leak} \quad (63)$$

Moreover, the number of moles of leakage  $H_2O$  per mole of carbon was determined by

$$n_{H_2O,leak} = w \cdot n_{O_2,leak} \quad (64)$$

Utilizing the corrected number of moles of  $CO_2$  and  $SO_2$  at the economizer exit as determined by means of Eqs. (53) and (54), the total number of gas moles at the preheater exit (per mole of carbon) are therein evaluated as

$$\sum n_{i,stack} = \sum n_{i,econ} + (n_{O_2} + n_{N_2} + n_{H_2O})_{leak} \quad (65)$$

Since the fuel composition is initially unknown, it is necessary to initiate iterative calculations to approximate the MAF composition of the coal. The real-time algorithm uses the coal mass flowrate correction factor expressed by Eq. (45) to evaluate actual coal mass flow. In that instance:

$$\dot{m}_{coal} = CoalFICorFac \times \dot{m}_{coal,plant} \quad (66)$$

The corrected value of the coal mass flowrate calculated per Eq. (66) is used to evaluate all plant performance parameters as described previously. For example, the real-time algorithm utilizes the methods described previously to calculate the steam cycle heat rate using Eq. (34). Likewise, the real-time algorithm determines the gross heat rate and net heat rate per Eqs. (35) and (36), respectively. The boiler efficiency is then calculated using Eq. (33).

**Calculation Sequence.** For the calibration algorithm, an accurate coal ultimate analysis (representative of the bulk coal being burned during the calibration) must be available. This analysis yields the coal composition and higher heating value. The calibration algorithm likewise requires such dynamic plant operation data as coal mass flowrate, steam heat transfer rate, primary and secondary air temperatures, ambient temperature and relative humidity, stack temperature, and continuous boiler rating, corresponding to

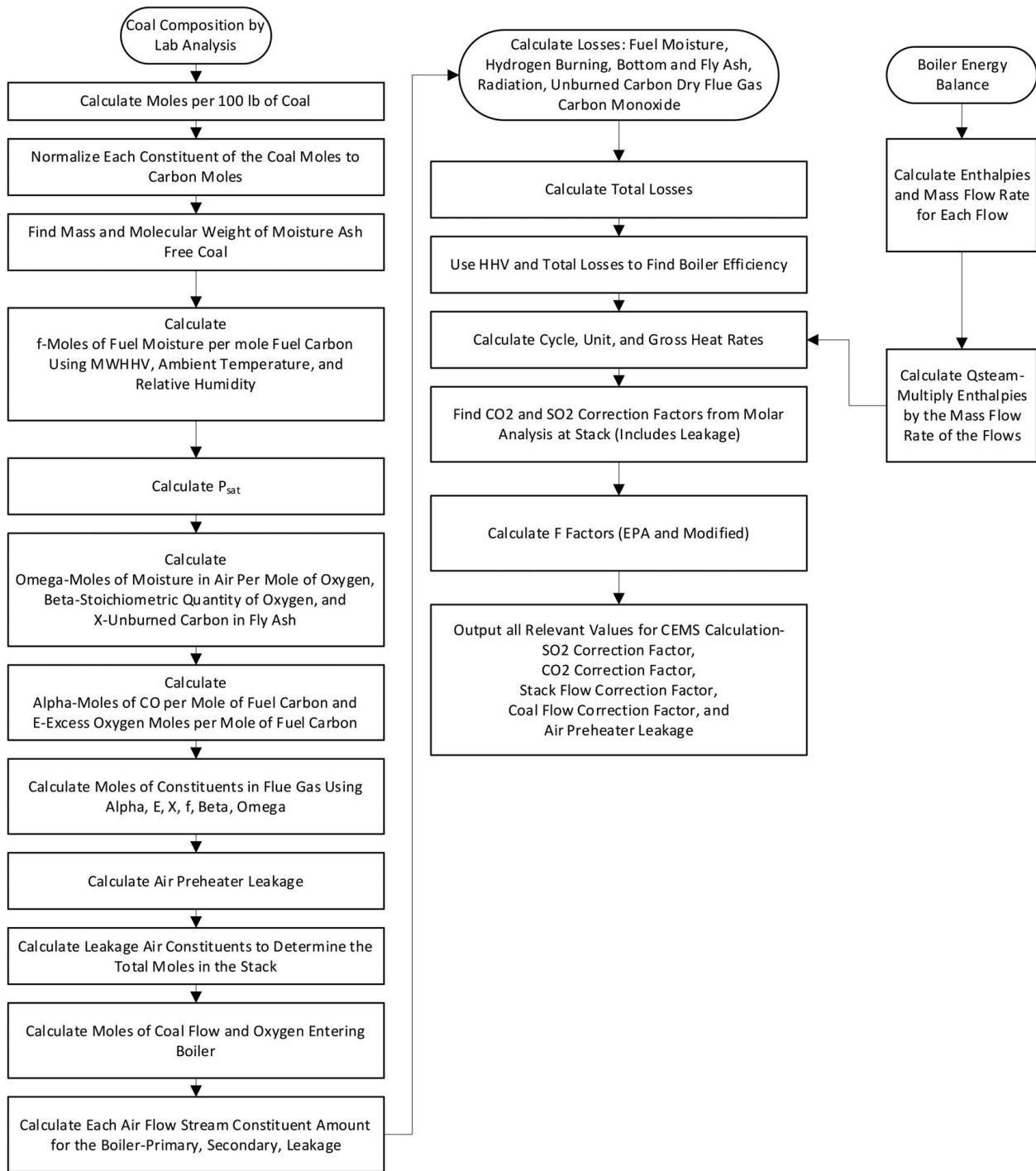


Fig. 3 Calibration Algorithm flowchart

when coal sampling occurred. Additional information needed by the calibration algorithm includes such quantities as the primary air/coal mass flow ratio, the LOI and fly ash percentage, the primary air/coal mass ratio, and boiler leakage. These parameters typically do not change significantly over time and were therein assumed to be static variables. If plant engineers know that one or more of these “constants” has changed they should perform another calibration with the new values. The calibration algorithm likewise relies on oxygen and carbon monoxide concentration data taken at the economizer exit to balance the combustion reaction equation. A representative flowchart of the calibration algorithm calculations is provided in Fig. 3. Further details regarding the calibration algorithm are provided in Ref. [17].

The calibration algorithm utilizes an accepted industry means of procuring a representative sample and then obtaining a laboratory coal ultimate analysis and limited plant data to balance the coal combustion equation, which essentially states the following:

$$\text{coal} + \text{air} = \text{products of combustion} \quad (67)$$

The implication is that the calibration algorithm presumes that the left-hand side of Eq. (67) is accurately known and can therein be used to evaluate the right-hand side. The real-time algorithm reverses this calculation, i.e., it utilizes CEMS data to analyze the composition of the combustion products and thus attempts to deduce the left-hand side of Eq. (67). This yields sufficient



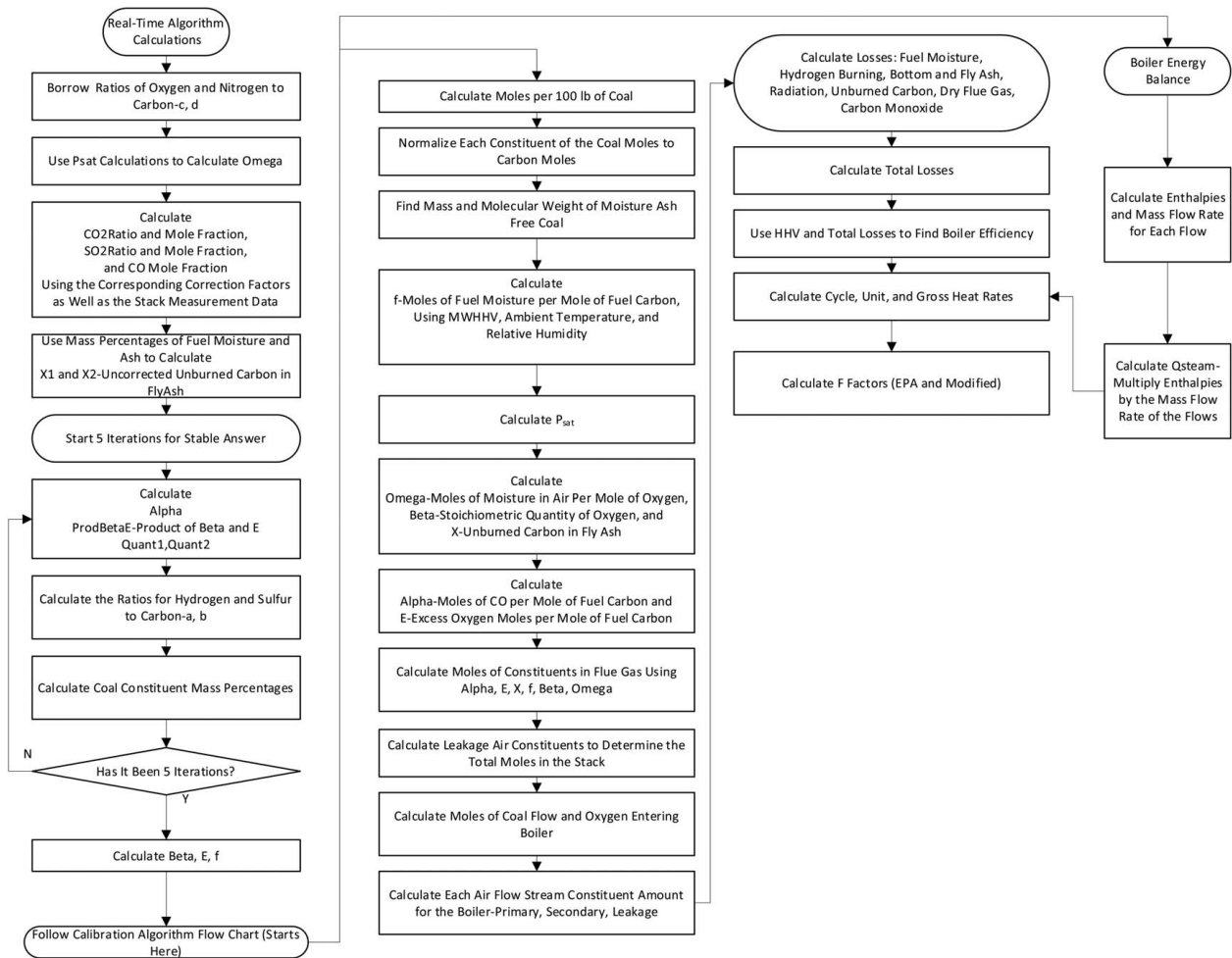


Fig. 4 Real-time Algorithm flowchart

information to closely approximate the actual MAF coal composition. CEMS measurements of  $\text{CO}_2$ ,  $\text{O}_2$ , and  $\text{SO}_2$  concentrations are required. If a scrubber is installed before the stack, the method discussed in this paper requires that CEMS measurements must be performed before the scrubber.

For the real-time algorithm of the output-loss method, the ultimate analysis of the coal is assumed to be an unknown. To solve for the coal composition, values for the molar ratios of oxygen and nitrogen to carbon, as well as values of fuel moisture and ash percentages, are borrowed from the latest ultimate analysis. This permits an estimation of the moisture-ash-free coal composition to be calculated. A static LOI value is used to calculate a preliminary of unburned carbon  $x$ . Based on plant data for the ambient pressure and relative humidity, there is sufficient information to determine the moisture in the air. Correction factors obtained from the calibration algorithm are used to adjust the CEMS measurements taken in the air preheater exit back to their presumed values at the economizer exit, thereby accounting for dilution caused by air preheater leakage. Since the fuel composition is unknown, a series of iterative calculations are performed, commencing from an initial estimate that the MAF coal is comprised entirely of carbon. Five iterations are then performed to continually update the coal composition, including solving simultaneous equations for  $\beta$  and  $E$ , as well as values for unburned carbon and carbon monoxide concentration. The most recently available ultimate analysis is provided to the real-time algorithm, to ensure its best accuracy. Once the coal composition is inferred using the iterative procedure, the remaining losses, efficiency, and heat rate calculations in the real-time algorithm are identical to those employed by

the calibration algorithm. Figure. 4 depicts the flowchart for the real-time algorithm. For additional aspects of the real-time algorithm calculation procedure, refer to Ref. [17].

## Model Validation

To verify that the real-time algorithm can provide values of power plant performance parameters such as heat rate that compare closely to those resulting from PTC 4 testing, data from a series of performance tests conducted by a reputable company that specializes in power plant performance testing were made available to this investigation. The identity of the test agent is not herein revealed due to concerns about the confidentiality of the plant's data. The testing occurred over the span of several days on a particular coal-fired steam EGU. The goal was to determine the instantaneous heat rate for the plant, which was operated over a range of power outputs, i.e., the gross generation. In one instance, the plant was operated at full load, herein designated as valves wide open (VWO), where the nominal power output was 470 MW ( $1.60 \times 10^9$  Btu/h). Additional performance tests were carried out at loads of 400 MW ( $1.37 \times 10^9$  Btu/h), 350 MW ( $1.19 \times 10^9$  Btu/h), 280 MW ( $0.96 \times 10^9$  Btu/h), and 200 MW ( $0.68 \times 10^9$  Btu/h). For each case, the testing strictly conformed to ASME PTC 4-2013 [1]. Over the span of loads considered in the performance testing, an ultimate analysis of the coal was obtained per Ref. [18], thereby enabling evaluation of its current composition and corresponding higher heating value. Additional measurements to support the heat rate assessment at each load were likewise

**Table 1 Static data**

BLRLK (%)	AIRCOAL, kg/kg (lbm/lbm)	LOI (%)	FLYASH (%)	$T_{ash}$ , °C (°F)
1.5	2	0.5	88	1093 (2000)

**Table 2 Ultimate analysis**

Components	Boiler load, MW (Btu/h)				
	VWO	400 ( $1.37 \times 10^9$ )	350 ( $1.19 \times 10^9$ )	280 ( $0.96 \times 10^9$ )	200 ( $0.68 \times 10^9$ )
C (%)	63.12	62.78	65.1	64.31	64.99
H (%)	4.24	4.14	4.21	4.24	4.41
S (%)	2.00	2.30	2.54	2.48	2.75
O (%)	7.06	7.66	6.86	7.01	7.33
N (%)	1.27	1.27	1.30	1.29	1.31
Fuel moisture (%)	13.07	13.7	11.99	12.15	10.99
ASH (%)	8.5	8.15	8.00	8.52	8.22
HHV, kJ/kg (Btu/lbm)	29,195 (11,262)	26,186 (11,258)	26,809 (11,526)	26,677 (11,469)	27,184 (11,687)

executed, including such quantities as steam heat transfer rate, coal flowrate, station service, and CEMS data.

Table 1 summarizes static data for boiler leakage, AIRCOAL, LOI, FLYASH, and  $T_{ash}$  that were employed in the real-time analysis. These quantities represent the amount of leakage air into the boiler compared to the total amount of air entering the boiler, the air-to-fuel ratio, the loss on ignition, the percentage of the total ash amount contained in the fly ash, and the bottom ash temperature, respectively. During the period of testing representative, coal samples were collected and sent to a laboratory for an ultimate analysis test. This test includes mass percentages for the constituents of the coal, fuel moisture and ash content of the coal, and the higher heating value for the coal. Table 2 contains the averaged ultimate analysis results for each load case, as supplied to the present research program. The dynamic data shown below in Table 3 provide those values measured during the period in which the coal samples used for the ultimate analysis were evaluated. These values consist of environmental data, as well as temperature data for the air flow streams, the amount of heat transferred to the steam, the coal flowrate, and CEMS measurements for certain emissions. It is important to note the oxygen and carbon monoxide measurements were performed at the economizer exit while the carbon dioxide and sulfur dioxide measurements were performed at the air preheater exit.

Plant performance metrics obtained by the testing company was made available to the present research program to allow assessment of the ability of the real-time algorithm to calculate the heat rate. The power plant performance company reported values of measured

heat rate obtained per PTC 4. These results are summarized for each plant load in Table 4, which likewise provides a comparison to the values predicted using the real-time algorithm. In these instances, the calibration algorithm utilized the most recent ultimate analysis to provide calibration factors needed by the real-time algorithm to evaluate the plant performance. Boiler efficiency was calculated per Eq. (41), wherein the control volume employed for the energy balance conformed closely to the steam boiler. As discussed previously, PTC 4 utilizes an alternate control volume analysis to determine boiler efficiency. Similarly, the cycle heat rate, gross heat rate, and net heat rate were determined using Eqs. (34), (35), and (36), respectively, using the real-time algorithm. The performance testing company did not supply data for the cycle heat rate at any plant load. It is apparent that the use of the latest calibration data yielded boiler efficiencies that closely matched the values obtained by PTC 4 test methods. The maximum discrepancy between boiler efficiencies determined using the real-time algorithm and PTC 4 test procedures was obtained at full load (VWO) and was less than a 1.7% difference. Likewise at VWO, the maximum disagreement between gross heat rate evaluated by the real-time algorithm and PTC 4 testing equaled  $-148$  Btu/kW-h, corresponding to a 1.7% difference.

The ability of the real-time performance algorithm to accurately assess instantaneous plant heat rate is presumably enhanced if the most current coal ultimate analysis is utilized. To investigate that contention, the coal composition obtained from the 400 MW test only was used to calibrate the real-time code; all other plant data such as steam heat transfer rate, coal flowrate, and station service

**Table 3 Dynamic measured data**

Variable	Boiler load, MW (Btu/h)				
	VWO	400 ( $1.37 \times 10^9$ )	350 ( $1.19 \times 10^9$ )	280 ( $0.96 \times 10^9$ )	200 ( $0.68 \times 10^9$ )
$T_{amb}$ , °C (°F)	31.8 (89.2)	28.6 (83.5)	28.2 (82.8)	28.5 (83.3)	27.8 (80.2)
Relative humidity (%)	79.7	71.9	74.2	76.4	75.8
$T_{PA}$ , °C (°F)	76.7 (170.0)	76.7 (170.0)	76.7 (170.0)	76.7 (170.0)	76.7 (170.0)
$T_{SA}$ , °C (°F)	326.6 (619.8)	311.2 (592.2)	301.5 (574.7)	298.1 (568.6)	288.8 (551.8)
$T_{LA}$ , °C (°F)	384.9 (724.9)	360.7 (681.3)	344.8 (652.6)	340.4 (644.7)	325.1 (617.2)
$\dot{Q}_{steam}$ , MW (Btu/h)	1084 ( $3.70 \times 10^9$ )	923 ( $3.15 \times 10^9$ )	815 ( $2.78 \times 10^9$ )	659 ( $2.25 \times 10^9$ )	486 ( $1.66 \times 10^9$ )
$\dot{m}_{coal}$ , kg/h (ton/h)	$1.66 \times 10^5$ (182.8)	$1.41 \times 10^5$ (155.0)	$1.21 \times 10^5$ (133.6)	$0.98 \times 10^5$ (108.4)	$0.71 \times 10^5$ (78.6)
$y_{O_2}$ (%)	3.33	2.98	3.97	3.52	4.15
$y_{CO}$ (ppm)	13.7	154.7	151.3	137.5	9.1
$y_{CO_2}$ (%)	13.8	14.1	14.0	13.8	12.8
$y_{SO_2}$ (ppm)	2395.9	2417.1	2396.8	2400.0	2400.0

**Table 4 Comparison—Plant performance obtained by PTC 4 and the real-time algorithm (five separate calibrations)**

Performance metric	Boiler load, MW (Btu/h)									
	VVO		400 (1.37 × 10 <sup>9</sup> )		350 (1.19 × 10 <sup>9</sup> )		280 (0.96 × 10 <sup>9</sup> )		200 (0.68 × 10 <sup>9</sup> )	
	Real-time	PTC4	Real-time	PTC4	Real-time	PTC4	Real-time	PTC4	Real-time	PTC4
Boiler efficiency (%)	88.42	89.91	89.50	90.30	90.06	90.41	90.57	90.58	91.28	90.40
Cycle heat rate (Btu/kW-h)	7880	—	7877	—	7942	—	8041	—	8293	—
Gross heat rate (Btu/kW-h)	8911	8763	8801	8723	8819	8785	8878	8877	9085	9173
Net heat rate (Btu/kW-h)	9684	9523	9586	9501	9687	9649	9908	9907	10,414	10,515

**Table 5 Comparison—Plant performance obtained by PTC 4 and the real-time algorithm**

Performance metric	Boiler load, MW (Btu/h)									
	VVO		400 (1.37 × 10 <sup>9</sup> )		350 (1.19 × 10 <sup>9</sup> )		280 (0.96 × 10 <sup>9</sup> )		200 (0.68 × 10 <sup>9</sup> )	
	Real-time	PTC4	Real-time	PTC4	Real-time	PTC4	Real-Time	PTC4	Real-Time	PTC4
Boiler efficiency (%)	88.57	89.91	89.50	90.30	91.05	90.41	90.72	90.58	90.59	90.40
Cycle heat rate (Btu/kW-h)	7880	—	7877	—	7942	—	8041	—	8293	—
Gross heat rate (Btu/kW-h)	8,897	8,763	8,801	8,723	8,723	8,785	8,863	8,877	9,154	9173
Net heat rate (Btu/kW-h)	9,668	9,523	9,586	9,501	9,581	9,649	9,892	9,907	10,493	10,515

Note: Calibrated using 400 MW (1.37 × 10<sup>9</sup> Btu/h) data.

corresponding to the actual data acquired at each load by means of the PTC 4 tests. The result of that analysis is summarized in Table 5, which likewise compares heat rates calculated using test methods mandated by PTC 4. In that instance, the maximum disagreement between boiler efficiencies was obtained at full load (VVO), which was less than a 1.5% difference. Therein, the subsequent difference in gross heat rate at VVO was −134 Btu/kW-h, once again equivalent to a 1.5% difference from the PTC 4 value. However, modest reductions in prediction comparisons of boiler efficiency and gross heat rate between the real-time algorithm and PTC 4 testing were noted when using a single (more outdated) calibration for the other plant loads. It must be noted that only *limited* data were provided by the performance testing company. In this study, the maximum time lag between obtaining an ultimate analysis for the plant operating at steady-state at a load of 400 MW, and a real-time calculation based on that calibration was no more than 96 h. Few EGUs update their coal analyses stored in their distributed control systems (DCS) at such short intervals. Unfortunately, many plants fail to update their DCS coal ultimate analyses even on a monthly or yearly basis. Therefore, this real-time adaptive performance-monitoring approach potentially represents a distinct improvement. It was shown that the real-time algorithm was capable of evaluating performance parameters such as boiler efficiency and heat rate that differed from similar values obtained using PTC 4 testing by less than 2% when a recent ultimate analysis of the coal was available for calibration.

## Conclusions and Recommendations

In this investigation, it was shown that the real-time algorithm accurately calculated such plant performance parameters as boiler efficiency, and gross and net unit heat rate. It can likewise be used in conjunction with a modified F-factor approach reported in Ref. [19] to more accurately evaluate the CO<sub>2</sub> produced per MW-h of gross plant generation as compared to CO<sub>2</sub> reporting per the standard EPA F-factor approach. Generally, power plant performance predictions of heat rate from the real-time algorithm were found to compare very closely to test data obtained using PTC 4-2013 test methods. It was shown that real-time performance assessments of instantaneous plant heat rate could be improved if

the most current coal ultimate analysis was utilized. Since the coal composition is typically not known in real-time, the procedure used a modified output-loss approach applied to a control volume that closely conformed to the boiler. A calibration algorithm utilized an ultimate analysis obtained while holding the plant load and other factors steady, thus permitting the calculation of correction factors used during real-time performance monitoring. The losses were calculated similarly to PTC 4-2013. However, the losses were expressed on a per-pound of as-fired coal basis, as opposed to a percentage of HHV of the coal, since that quantity is not known in real-time. Small differences were observed between the heat rates calculated by the real-time algorithm when an ultimate coal analysis measured for each load was utilized, versus heat rate values predicted by the real-time algorithm using only one (presumably outdated) coal ultimate analysis. These minor discrepancies were more apparent at the lower plant loads.

An advantage of the real-time algorithm based on the output-loss method is that it requires only permanent station CEMS sensors. This is unlike PTC 4 test procedures, where temporary instrumentation is needed. Furthermore, the results can be calculated and monitored in real-time. The real-time algorithm minimizes the need for expensive new instrumentation and permits the continuous monitoring of plant heat rate as the load changes. The real-time method is rooted in ASME PTC 4 and generally exhibits improved performance prediction uncertainty (1–3%), as compared to other current approaches (e.g., F-factor), where the accuracy may only be 3–14%. The real-time method relies on station instrumentation that is typically available and is easily calibrated. It accounts for cycling and load following and allows for Relative Accuracy Test Audits (RATA).

The investigation reported in this paper was performed on a single power plant. In anticipation of new EPA heat rate regulations [20] currently being promulgated for coal, gas, and industrial units, it would be advantageous to further develop the real-time code in order to apply this method to additional EGUs, with a priority for cogeneration and gas-fired units. Such studies would provide further guidance concerning whether additional costly instrumentation would be needed in practice or would require only the existing CEMS data currently available to the plant computers. For example, the applicability of the real-time algorithm is adversely affected if CEMS sensors are only available downstream of scrubbers. It is

desirable to install real-time software in plants that utilize a combination of dry- and wet-based CEMS measurements to emphasize the generality of the method. In Ref. [2], it was noted that the accuracy of the real-time heat rate monitoring protocol would be enhanced if accurate and robust methods were available to measure the moisture content in the flue gases in real-time. Such a deficiency is inherent to all currently available online EGU performance-monitoring methods. Further research would facilitate the determination of the uncertainty associated with coal analysis and fuel moisture on heat rate/CO<sub>2</sub> emissions on annual reporting. It is likewise proposed to investigate proposed metrics for observed plant changes using raw inputs as suitable triggers for calibration. Based on the analysis of these studies, recommended calibration triggers would be incorporated into the code. Specific suggestions include the collection of more extensive actual data at the plant(s) for a year, with new ultimate analyses being taken at least weekly, thereby yielding a minimum of 52 calibration data sets over all seasons and weather conditions. This would permit the determination of appropriate “flags” for recommended recalibrations. To provide further guidance regarding recommended re-calibration intervals, it is suggested to post-process the heat rate and other outputs from the real-time algorithm under several scenarios, e.g., using a single calibration for the year, or weekly calibrations for the year, etc. This would allow further comparison of the results from the real-time algorithm to corresponding evaluations of heat rate and CO<sub>2</sub> production per MW as measured by means of testing conducted strictly according to PTC 4-2013. The accuracy of the heat rate monitoring protocol described in this paper could be enhanced if accurate and robust methods were available to measure the moisture content in the flue gases in real-time. This would provide additional information needed to evaluate fuel moisture on an instantaneous basis. Such a deficiency is inherent to all currently available online EGU performance-monitoring methods. This issue merits further investigation.

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## Conflict of Interest

There are no conflicts of interest. This article does not include research in which human participants were involved. Informed consent is not applicable. This article does not include any research in which animal participants were involved.

## Data Availability Statement

The data sets generated and supporting the findings of this article are obtainable from the corresponding author upon reasonable request.

## Nomenclature

- $a$  = moles of hydrogen per mole of fuel carbon mole/mole
- $b$  = moles of sulfur per mole of fuel carbon mole/mole
- $c$  = moles of oxygen per mole of fuel carbon mole/mole
- $d$  = moles of nitrogen per mole of fuel carbon mole/mole

- $f$  = moles of H<sub>2</sub>O per mole of fuel carbon mole/mole
- $\ell$  = thermal losses per unit mass of coal MW/kg (Btu/lbm)
- $m$  = mass, kg (lbm)
- $n$  = moles mole
- $w$  = moles of H<sub>2</sub>O per mole of O<sub>2</sub> mole/mole
- $x$  = moles of unburned carbon per mole of fuel carbon kg/kg (lbm/lbm)
- $y$  = mole fraction mole/mole
- $\dot{Q}$  = heat transfer rate MW (Btu/h)
- $A$  = ash mass fraction kg/kg (lbm/lbm)
- $E$  = moles of excess O<sub>2</sub> per mole of fuel carbon mole/mole
- $M$  = moisture mass fraction kg/kg (lbm/lbm)
- $P$  = plant electric generation MW
- $\dot{m}$  = mass flowrate kg/h (lbm/h)
- $\dot{n}$  = molar flowrate mole/h
- $\dot{E}$  = energy transfer rate kW (Btu/h)
- AIRCOAL = air-to-coal mass ratio in primary air stream kg/kg (lbm/lbm)
- ASH = ultimate analysis ash mass %
- CoalFCorFac = coal flow correction factor kg/kg (lbm/lbm)
- CO<sub>2</sub>CorFac = CO<sub>2</sub> correction factor mole/mole
- FC = fuel carbon per unit weight of coal kg/kg (lbm/lbm)
- FLYASH = fraction of total ash appearing as fly ash kg/kg (lbm/lbm)
- FM = ultimate analysis of moisture mass %
- FM<sub>2</sub> = moles of H<sub>2</sub>O per mole of fuel carbon mole/mole
- Le = moles of O<sub>2</sub> leaking from air preheater mole
- Lo = thermal losses kW (Btu/h)
- SO<sub>2</sub>CorFac = SO<sub>2</sub> Correction Factor mole/mole
- TOTAL ASH = mass of total ash in exhaust, kg (lbm)
- UC = mass of unburned carbon in fly ash, kg (lbm)
- UCTASH = fraction of unburned carbon in total ash, lbm/lbm
- X<sub>2</sub> = moles of carbon per unit weight of MAF coal, kg/mole (lbm/mole)

## Greek Symbols

- $\alpha$  = moles of CO per mole of fuel carbon, mole/mole
- $\beta$  = stoichiometric combustion air molar coefficient, mole/mole
- $\eta_B$  = boiler efficiency, %
- $\omega$  = humidity ratio, kg/kg (lbm/lbm)

## Subscripts

- AF = as-fired
- air = air
- ash = ash
- Cycle = cycle
- components = components
- coal = coal
- dry air = dry air
- dry gases = dry gases
- econ = economizer exit
- flue gas = flue gas
- formation = formation
- Gross = gross
- in = inlet
- LA = leakage air
- leak = leak
- leakage air = leakage air
- MAF = moisture-ash-free
- moisture = moisture



*Net* = net  
*out* = outlet  
*PA* = primary air  
*Plant* = plant instrumentation  
*rad* = radiation  
*SA* = secondary air  
*Stack* = air preheater exit  
*Standard* = standard conditions  
*Steam* = steam  
*total* = total  
*Unburned carbon* = unburned carbon

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