APPENDIX 1
MEASURING BOILER EFFICIENCY

Maintaining optimum boiler efficiency not only minimizes CO_2 emissions, it conserves fuel resources and saves money. One might therefore expect boiler efficiency to be routinely monitored, especially in larger heating and industrial steam plants. Usually, however, it is addressed only once or twice a year, by a technician setting up the automatic controls, and whose focus is more likely to be on safe, trouble-free operation than on optimum efficiency.

The standard for determining boiler efficiency in North America is the ASME Power Test Code (ASME PTC 4.1-1964, reaffirmed 1973, also known as ANSI PTC 4.1-1974, reaffirmed 1985.). The ASME has published additional test codes, such as those for air heaters, (PTC 41), gas turbine heat recovery steam generators (PTC 4.4), large incinerators (PTC 33) and reciprocating internal combustion engines (PTC 17). As Poster App 1-1 shows, there are numerous inputs and outputs that affect boiler efficiency, and trying to evaluate all of them is a lot of work. However, for boilers fired with natural gas and fuel oil, many of the losses do not apply, and others are small enough to be rolled into an "unaccounted for" category for which a value, e.g., 0.2%, can be assumed.

This leaves three main losses to be considered as shown in Poster App 1-2:
1) dry flue gas loss,
2) loss due to moisture from the combustion of hydrogen, and
3) radiation and convection loss.

They can be easily determined, using equipment that should be available to every steam plant and is sufficiently accurate to guide the owner and operator toward minimizing fuel use by optimizing efficiency.

Dry Flue Gas Loss

The dry flue gas loss accounts for the heat lost up the stack in the "dry" products of combustion, that is, CO_2, O_2, N_2, CO and SO_2. These carry away only sensible heat, whereas the "wet" products, mainly moisture from the combustion of hydrogen, carry away both latent and sensible heat. Environmental regulations limit CO emissions to about 400 ppm, and modern combustion systems usually produce much less than that, so from the viewpoint of efficiency CO can be treated as negligible. This simplifies the calculations.

The ASME Power Test Code uses Imperial units, (lb, °F and Btu/lb) and so calculates dry flue gas loss as follows:

$$L_{DG}, \% = [DG \times C_p \times (FGT - CAT)] \times 100 \div HHV$$

in which   DG is the weight of dry flue gas, lb/lb of fuel,

ASME BOILER EFFICIENCY
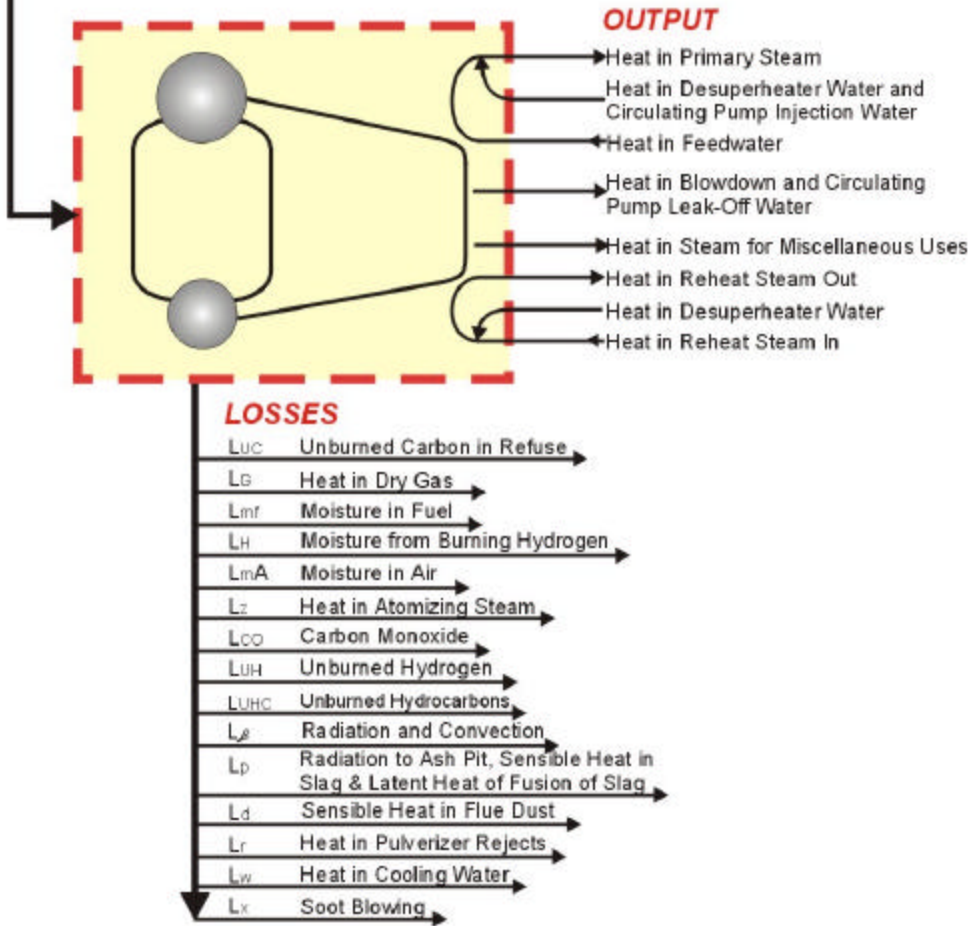
INPUT

HEAT IN FUEL (Hf) (CHEMICAL)

B_A	Heat in Entering Air
B_z	Heat in Atomizing Steam
B_r	Sensible Heat in Fuel
B_x	Pulverizer or Crusher Power
B_x	Boiler Circulating Pump Power
B_x	Primary Air Fan Power
B_x	Recirculating Gas Fan Power
B_{mA}	Heat Supplied by Moisture in Entering Air
B_w	Heat in Cooling Water

EFFICIENCY

OUTPUT = Input - Losses

$$\text{EFFICIENCY \%} = \frac{\text{Output}}{\text{Input}} \times 100$$

$$= \frac{\text{Input - Losses}}{\text{Input}} \times 100$$

OUTPUT

- Heat in Primary Steam
- Heat in Desuperheater Water and Circulating Pump Injection Water
- Heat in Feedwater
- Heat in Blowdown and Circulating Pump Leak-Off Water
- Heat in Steam for Miscellaneous Uses
- Heat in Reheat Steam Out
- Heat in Desuperheater Water
- Heat in Reheat Steam In

LOSSES

L_{uc}	Unburned Carbon in Refuse
L_G	Heat in Dry Gas
L_{mf}	Moisture in Fuel
L_H	Moisture from Burning Hydrogen
L_{mA}	Moisture in Air
L_z	Heat in Atomizing Steam
L_{CO}	Carbon Monoxide
L_{UH}	Unburned Hydrogen
L_{UHC}	Unburned Hydrocarbons
L_β	Radiation and Convection
L_p	Radiation to Ash Pit, Sensible Heat in Slag & Latent Heat of Fusion of Slag
L_d	Sensible Heat in Flue Dust
L_r	Heat in Pulverizer Rejects
L_w	Heat in Cooling Water
L_x	Soot Blowing

Poster App 1-1   ASME Boiler Efficiency

C_p is the specific heat of flue gas, usually assumed to be 0.24,
FGT is the flue gas temperature, °F,
CAT is the combustion air temperature, °F,
HHV is the higher heating value of the fuel, Btu/lb.

The formula can be simplified to $\quad L_{DG}, \% = [24 \text{ x } DG \text{ x } (FGT - CAT)] \div HHV$

If temperatures are measured in °C, other units remaining unchanged, the formula becomes

$$L_{DG} = [43.2 \text{ x } DG \text{ x } (FGT - CAT)] \div HHV$$

The weight of dry gas per lb of fuel, DG, varies with fuel composition and the amount of excess air used for combustion. For the normal case of no CO or unburned hydrocarbons it can be calculated as follows:

$$DG, \text{ lb/lb fuel} = (11CO_2 + 8O_2 + 7N_2) \text{ x } (C + 0.375S) \div 3CO_2$$

in which $\qquad CO_2$ and O_2 are % by volume in the flue gas,
N_2 is % by volume in the flue gas, $= 100 - CO_2 - O_2$,
C and S are weight fractions from the fuel analysis, that is, lb/lb fuel

It is important to note that the foregoing equation requires the flue gas analysis to be reported on the dry basis; that is, the volumes of CO_2 and O_2 are calculated as a percentage of the dry flue gas volume, excluding any water vapour. This is because early gas analysis techniques employed wet chemistry, which condensed the water vapour in the process of taking the sample. Many modern analytical techniques, such as those employing infrared or paramagnetic principles, also measure on a dry gas basis because they require moisture-free samples to avoid damage to the detection cells. These analyzers are set up with a sample conditioning system that removes moisture from the gas sample. However, some analyzers, such as in-situ oxygen detectors employing a zirconium oxide cell, measure on the wet gas basis. Results from such equipment need to be corrected to a dry gas basis before they are used in the ASME equations. This is easily done using correction factors as follows:
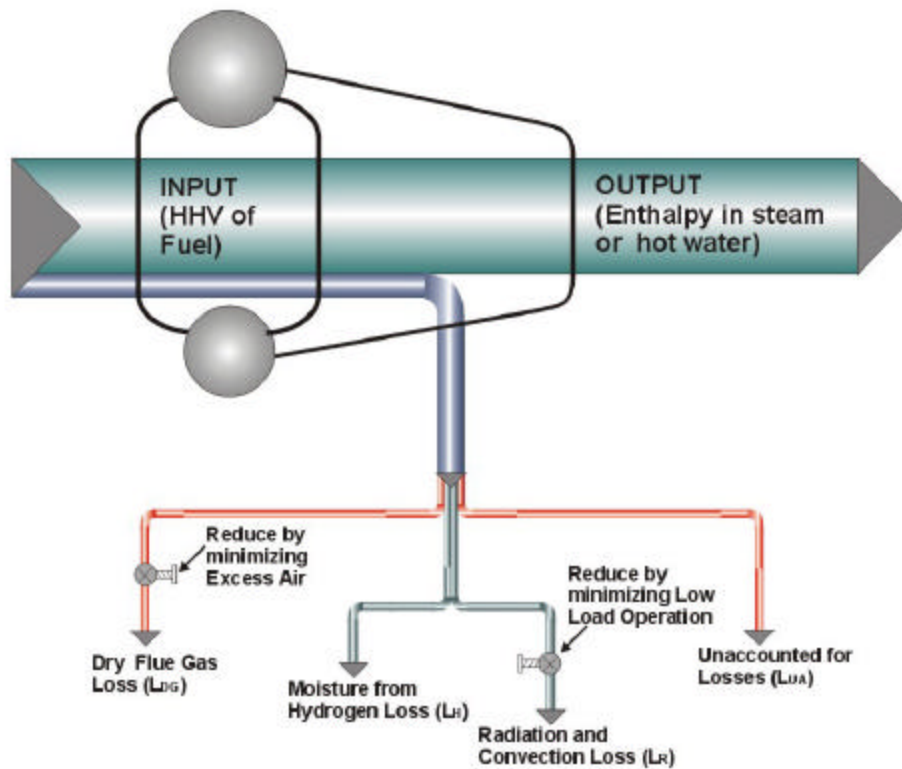
%, dry basis = %, wet basis x F

Approximate values for F, suitable for quick assessment of boiler efficiency, are
Natural gas:	F = 1.19
No. 2 oil:	F = 1.12
No. 4 oil:	F = 1.10

For more precise work, F can be selected from Table App 1-1.

SIMPLIFIED BOILER EFFICIENCY

INPUT (HHV of Fuel)

OUTPUT (Enthalpy in steam or hot water)

Reduce by minimizing Excess Air

Reduce by minimizing Low Load Operation

Dry Flue Gas Loss (L_{DG})

Moisture from Hydrogen Loss (L_H)

Radiation and Convection Loss (L_R)

Unaccounted for Losses (L_{UA})

L_{DG} (%) = [24 x DG x (FGT - CAT)] / HHV
  DG (lb/lb fuel) = (11 CO_2 + 8 O_2 + 7 N_2) x (C + 0.3755) / 3 CO_2
  FGT = Flue Gas Temp., °F
  CAT = Combustion Air Temp., °F
  HHV = Higher Heating Value of fuel, Btu/lb
  CO_2 and O_2 = % by volume in the flue gas
  N_2 = 100 - CO_2 - O_2
  C and S = Weight fractions in fuel analysis

L_H (%) = [900 x H_2 x (hg - hf)] / HHV
  H_2 = weight fractions in fuel analysis
  hg = 1055 + (0.467 X FGT), Btu/lb
  hf = CAT - 32, Btu/lb

L_R (%) = see Radiation and Convection Losses Chart

L_{UA} (%) = assume 0.1% for natural gas
               0.2% for light oil

Poster App 1-2   Simplified Boiler Efficiency

Table App 1-1   **Factors to Convert Wet Gas Analyses to Dry Gas Basis***

Wet Gas Measured CO_2 or O_2 %	Correction Factor F					
	Natural gas		No. 2 oil		No. 4 oil	
	CO_2	O_2	CO_2	O_2	CO_2	O_2
1	-	1.22	-	1.13	-	1.12
2	-	1.21	-	1.12	-	1.11
3	-	1.19	-	1.12	-	1.10
4	-	1.18	-	1.11	-	1.10
5	-	1.17	-	1.10	-	1.09
6	1.14	1.15	-	1.10	-	1.09
7	1.16	1.14	-	1.09	-	1.08
8	1.19	1.13	1.08	1.08	1.07	1.07
9	1.22	1.12	1.09	1.07	1.08	1.07
10	-	-	1.10	-	1.09	-
11	-	-	1.11	-	1.10	-
12	-	-	1.12	-	1.11	-
13	-	-	1.14	-	1.12	-
14	-	-	-	-	1.13	-

*As an example: A natural gas fired boiler's flue gas was measured on a wet basis to be 6% O_2 and 9% CO_2, the corrections would be:

% O_2, dry basis = %, wet basis x F = 6% x 1.15 = 6.9%
% CO_2, dry basis = %, wet basis x F = 9% x 1.22 = 10.98%

So to determine dry flue gas loss, one needs:

- Measurements of flue gas temperature and combustion air temperature, which are part of the normal complement of instrumentation, or can be readily determined.

- Flue gas analysis for CO_2 and O_2, which can be determined by a portable flue gas analyzer with an appropriate water trap in the sampling system. Some plants have continuous gas analyzers in place.

- Fuel analysis and heating value. Typical values are shown in Table App 1-2. The composition of No. 6 oil is more variable than the others, particularly with respect to sulphur and fuel-bound nitrogen, so the values in Table App 1-2 should be viewed as indicative only. It is better to have an analysis performed on a representative sample of the oil delivered to the plant.

One can see from the equations that the quantity of dry gas, DG, can be reduced by reducing the amount of oxygen in the flue gas, that is, by reducing the excess air. Reducing DG in turn reduces the dry flue gas loss, L_{DG}. One can also see that reducing the difference between the flue gas temperature FGT and combustion air temperature, CAT, the reference temperature for determining boiler efficiency, can reduce L_{DG}.

Preheating the combustion air, raising the CAT, and installing an economizer to recover heat from the flue gases, lower the FGT, can reduce this difference.

Table App 1-2   **Typical Analyses for Common Fossil Fuels**

Fuel	Natural Gas	No. 2 Oil (light oil)	No. 4 Oil (bunker A)	No. 6 Oil (bunker C)
HHV, Btu/lb	22,450	19,450	18,750	18,350
Ultimate analysis, weight fraction				
Carbon	0.721	0.865	0.867	0.867
Hydrogen	0.239	0.132	0.115	0.108
Sulphur	Nil	0.003	0.015	0.020
Nitrogen	0.032	Nil	0.003	0.005
Oxygen	0.008	Nil	nil	nil
lb $CO_2/10^6$ Btu input	117.8	163.1	169.6	173.2

It is not obvious from the formula for L_{DG} that reducing the quantity of dry flue gas DG also reduces the flue gas temperature. However, considering that a boiler represents a fixed heat exchange area, it is understandable that reducing the gas flow over that surface tends to reduce the final temperature of the gas. Thus, reducing excess air has a compounded favourable effect on boiler efficiency, and maintaining close control over excess air is the best opportunity for improving boiler efficiency. Excessive emission of CO and unburned hydrocarbons, and unsafe boiler operation are factors that limit the extent to which excess air can be reduced. Good burners and precise combustion controls are necessary for good results.

Loss Due to Moisture from the Combustion of Hydrogen

As explained in Chapter 3, the hydrogen component of fuel leaves the boiler as water vapour, taking with it the enthalpy, or heat content, corresponding to its conditions of temperature and pressure. It is steam at very low pressure but fairly high temperature, the stack temperature, and most of its enthalpy is in the heat of vapourization. This makes it a significant loss, commonly about 11% for natural gas and 7% for fuel oil. The difference reflects the relative hydrogen content of these two fuels.

The ASME Power Test Code formula for calculating the loss due to moisture from the combustion of hydrogen is:

$$L_H, \% = [900 \times H_2 \times (h_g - h_f)] \div HHV$$

in which H_2 is the weight fraction of hydrogen in the ultimate analysis of the fuel,

HHV is the higher heating value,

h_g is the enthalpy in Btu/lb of water vapour at 1 psi and the flue gas
temperature (FGT) in °F, and

h_f is the enthalpy of water at the combustion air temperature (CAT) in °F.

h_g can be determined from steam tables or from the equation

h_g , Btu/lb = 1055 + (0.467 x FGT).

h_f can also be determined from steam tables, or from the simple relationship

h_f , Btu/lb = CAT - 32.

So, knowing the flue gas temperature, combustion air temperature and fuel analytical data, L_H can be readily calculated. Unfortunately, there is not much the operator can do to reduce it. Since most of the lost heat is in the heat of vapourization, measures that reduce the flue gas temperature have only a small effect. One measure, particularly effective when firing natural gas, is to pass the flue gas through a condensing heat exchanger, which recovers the heat of vapourization by converting the water vapour back to liquid form. This method requires additional equipment and is discussed in Chapters 2 and 3.

Loss Due to Radiation and Convection

The nature and extent of the loss due to radiation and convection (L_R) are discussed in Chapter 3. L_R is not normally measured; instead it is estimated using a chart prepared by the American Boiler Manufacturers' Association (ABMA). Values applicable to modern boilers having all walls watercooled have been selected from the ABMA chart and are presented in Figure App 1-1.
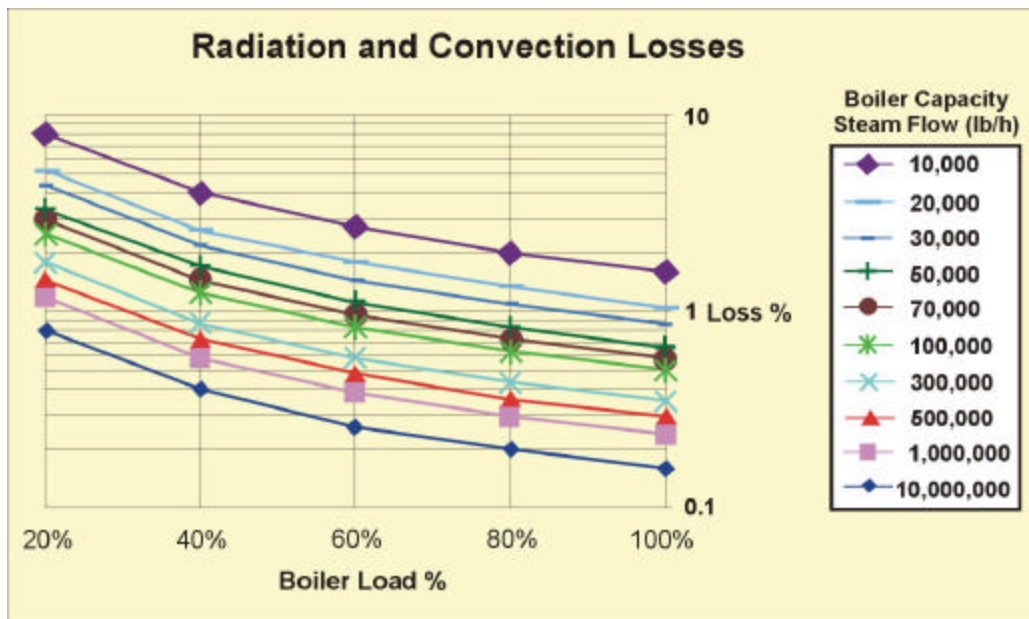

Figure App 1-1   Radiation and Convection Losses for Various Boiler Sizes

As pointed out in Chapter 3, L_R can be minimized by distributing demand among the available boilers to keep those in operation in the upper load range. Also, the lost heat usually warms up the boiler room, sometimes uncomfortably so, and sometimes it is practical to recover some of this heat by extending the forced draft fan intake to near the ceiling. This raises the combustion air temperature (CAT) and somewhat reduces the dry flue gas loss (L_{DG}). However, if this is done the effects on fan capacity and boiler room ventilation should be checked.

"Unaccounted-For" Losses

As indicated in Poster App 1-2, reasonable assumptions concerning these losses are 0.1% for natural gas, 0.2% for light oil. For heavy oil, a value between 0.3 and 0.5% may be appropriate, to account for fuel heating and, perhaps, atomizing steam. Plants burning solid fuels require individual assessment to address the additional losses such as carbon in ash.

Using Boiler Efficiency Data

Having determined flue gas analysis, flue gas temperature and combustion air temperature for each boiler at perhaps four or five points over its load range, the operator can then make use of this data to optimize plant performance. First, by looking at O_2 and CO levels in the flue gas, conclusions can be drawn about the adjustment of the air/fuel controls, and whether dry flue gas loss (L_{DG}) can be safely reduced by reducing excess air. Second, boiler efficiency at each test point can be obtained by adding up the losses, as determined from the foregoing procedures, and subtracting from 100. That is;

$$\textbf{Efficiency } (\eta) = 100 - (L_{DG} + L_H + L_R + L_{UA})$$

Then an efficiency curve can be drawn for each boiler. Usually boiler efficiency is highest somewhere between 50% and 80% of maximum capacity rating (MCR). It is generally lower at low load due to higher excess air and higher radiation and convection losses, and lower at high load due to high stack temperature. With the boiler efficiency curves as a guide the operator can shift loads between boilers to maintain each at close to its highest efficiency. In designing or refurbishing a plant, the profile of demand versus time should be carefully considered, and boiler sizes should be selected so that they operate in the most efficient range most of the time.

If existing boilers have a high stack temperature at full load, and operate there much of the time, it might be cost effective to add heat recovery equipment such as economizers or air heaters.