Improving Energy Efficiency of Boiler Systems

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IMPROVING ENERGY EFFICIENCY OF BOILER SYSTEMS

When considering boiler energy savings, invariably the discussion involves the topic of boiler efficiency.

The boiler suppliers and sales personnel will often cite various numbers, like the boiler has a thermal efficiency of 85%, combustion efficiency of 87%, a boiler efficiency of 80%, and a fuel-to-steam efficiency of 83%. What does these mean?

Typically,

1) Thermal efficiency reflects how well the boiler vessel transfers heat. The figure usually excludes radiation and convection losses.

2) Combustion efficiency typically indicates the ability of the burner to use fuel completely without generating carbon monoxide or leaving hydrocarbons unburned.

3) Boiler efficiency could mean almost anything. Any fuel-use figure must compare energy put into the boiler with energy coming out.

4) "Fuel to steam efficiency" is accepted as a true input/output value.

Each term represents something different and there is no way to tell, which boiler will use less fuel in the same application! The trouble is that there are several norms to determine the efficiencies figures and it is practically very difficult to verify these without costly test procedures. The easiest and most cost effective method is to review the basic boiler design data and estimate the efficiency value on five (5) broad elements.

1) **Boiler Stack Temperature:** Boiler stack temperature is the temperature of the combustion gases leaving the boiler. This temperature represents the major portion of the energy not converted to usable output. The higher the temperature, the less energy transferred to output and the lower the boiler efficiency. When stack temperature is evaluated, it is important to determine if the value is proven. For example, if a boiler runs on natural gas with a stack temperature of 350°F, the maximum theoretical efficiency of the unit is 83.5%. For the boiler to operate at 84% efficiency, the stack temperature must be less than 350°F.

2) **Heat Content of Fuel:** The efficiency calculation requires knowledge of the calorific value of the fuel (heat content), its carbon to hydrogen ratio, and whether the water produced is lost as steam or is condensed, and whether the latent heat (heat required to turn water into steam) is recovered.

Disagreements exist on what is considered an "energy input". Unfortunately any fuel has two widely published energy contents. They are:

- The Higher Heating Value (HHV), also called Gross Calorific Value (GCV)

- The Lower Heating Value (LHV), also called the Net Calorific Value (NCV)

The gross calorific value (GCV) is the higher figure and assumes that all heat available form the fuel is to be recovered, including latent heat. In most equipment, this is not so the case, and the calculations of efficiency based on gross calorific value will give maximum obtainable efficiencies much lower than 100%, due to this irrecoverable loss.

Both the gross calorific value and net calorific value are equally valid, but for comparison purposes, a particular convention should be used throughout.

3) **Fuel Specification:** The fuel specified has a dramatic effect on efficiency. With gaseous fuels having higher the hydrogen content, the more water vapor is formed during combustion. The result is energy loss as the vapor absorbs energy in the boiler and lowers the efficiency of the equipment.

The specification used to calculate efficiency must be based on the fuel to be used at the installation. As a rule, typical natural gas has a hydrogen/-carbon (H/C) ratio of 0.31. If an H/C ratio of 0.25 is used for calculating efficiency, the value increases from 82.5% to 83.8%.

4) **Excess Air Levels:** Excess air is supplied to the boiler beyond what is required for complete combustion primarily to ensure complete combustion and to allow for normal variations in combustion. A certain amount of excess air is provided to the burner as a safety factor for sufficient combustion air.

5) **Ambient Air temperature and Relative Humidity:** Ambient conditions have a dramatic effect on boiler efficiency. Most efficiency calculations use an ambient temperature of 80°F and a relative humidity of 30%. Efficiency changes more than 0.5% for every 20°F change in ambient temperature. Changes in air humidity would have similar effects; the more the humidity, the lower will be the efficiency.

Comparing these five factors along with the stated efficiency will make you understand efficiency values more thoroughly. An important thing to note is to make the comparisons on equal footings. Consider the examples below:

- If two boilers are stated as operating at the same stack temperature and one has less heating surface, stack temperature on the boiler with less heating surface should be challenged.

- If two boilers are stated as operating at 15% excess air and one has a very complex burner linkage design or does not include a high-quality air damper arrangement, it is questionable that it will operate at the stated excess air level.

- If two boilers of similar length and width are compared and one has more flue gas passes (number of times the flue gas travels through the boiler heat exchanger), the boiler with the greater number of passes should have a lower stack temperature.

Evaluating Boiler Efficiencies

The most basic efficiency norm which everybody agrees is the "input/output" ratio:

$$\text{Efficiency }(\eta) = \frac{E_{out}}{E_{in}}$$

Where

- E_{out} is the energy needed to convert feed water entering the boiler at a specific pressure and temperature to steam leaving the boiler at a specific pressure and temperature. (This includes the energy picked up by the blow down and not converted into steam).

- E_{in} is the input energy into the boiler. The heat input is based on the high heat (gross calorific) value of fuel for efficiency calculations in US, UK and many other countries. Germany uses low heat (net calorific) value basis, implying that for an identical boiler, the stated efficiency will be higher.

There are two methods of assessing boiler efficiency;

1. Input – output or direct method, and

2. Heat loss or indirect method.

Direct Method for Calculating Boiler Efficiency

Direct method compares the energy gain of the working fluid (water and steam) to the energy content of the fuel. This is also known as 'input-output method' due to the fact that it needs only

the useful output (steam) and the heat input (i.e. fuel) for evaluating the efficiency. The efficiency is than estimated using equation below:

$$\% E = \frac{Output}{Input} = \frac{Enthalpy\ of\ Steam - Enthalpy\ of\ feedwater}{Heat\ released\ in\ Boiler} * 100$$

Procedure:

1) Measure quantity of steam flow kg (or lb.) over a set period, e.g. one hour period. Use steam integrator readings, if available, and correct for orifice calibration pressure. Alternatively, use the feedwater integrator, if available, which will in most cases not require a correction for pressure.

2) Measure the quantity of fuel used over the same period. Use the gas or oil integrator, or determine the mass of solid fuel used.

3) Determine the working pressure in Kg/cm^2 (psi) and superheat temperature, °C (°F), if any.

4) Determine the temperature of feedwater °C (°F)

5) Convert steam flow, feedwater flow and fuel flow to identical energy units, e.g. kJ/kg or Btu/lb.

6) Determine the type of fuel and gross calorific value of the fuel (GCV or HHV) in kJ/kg or Btu/lb.

7) Calculate the efficiency using equation:

$$\% E = \frac{Output}{Input} = \frac{Enthalpy\ of\ Steam - Enthalpy\ of\ feedwater}{Heat\ released\ in\ Boiler} * 100$$

Direct method is simple in a way that it requires few parameters for computations and needs few instruments for monitoring. However this method may not be as accurate due to errors in metering fuel flow and steam flow. In practice, only very large industrial set ups and electric utility companies are instrumented well enough to obtain the required data.

Indirect Method or Heat Loss Method for Calculating Boiler Efficiency

Here the efficiency is estimated by summing the losses and comparing with the heat input. The major heat losses from boiler are due to:

1. High temperature flue gas leaving the stack

2. Moisture in fuel and combustion air

3. Combustion of hydrogen (leaves boiler stack as water vapor)

4. Heat in un-burnt combustibles in refuse

5. Radiation from the boiler surfaces

6. Unaccounted for un-measured losses

Sum up the losses and calculate the efficiency using equation:

Efficiency (% E) = 100 – Σ Losses

Or

$$\% E = \frac{Heat\ Input - Heat\ Losses}{Heat\ Input}$$

$$\% E = 100 - \left(\frac{Heat\ losses}{Heat\ in\ fuel}\right) * 100$$

Evaluating Heat Losses from Boiler

The procedure for calculating boiler efficiency by indirect method is illustrated below.

1) Dry Flue Gas Loss (LDG)

Heat is lost in the "dry" products of combustion, which carry only sensible heat since no change of state was involved. These products are carbon-dioxide (CO_2), carbon monoxide (CO), oxygen (O_2), nitrogen (N_2) and sulfur dioxide (SO_2). Concentrations of SO_2 and CO are normally in the parts-per-million (ppm) range so, from the viewpoint of heat loss, they can be ignored. Calculate the dry flue gas loss (LDG) using the following formula:

LDG, % = [DG x Cp x (FGT - CAT)] x 100 / HHV

Where:

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

- Cp 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 LDG, % = [24 x DG x (FGT - CAT)] / HHV

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

LDG = [43.2 x DG x (FGT - CAT)] ÷ HHV

The weight of dry gas (DG), varies with fuel composition and the amount of excess air used for combustion. For the normal case of zero CO or unburned hydrocarbons, it can be calculated as:

$DG = (11CO_2 + 8O_2 + 7N_2) \times (C + 0.375S) / 3CO_2$

Where

- 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 (lb/lb fuel)

What do you need to determine LDG?

To determine dry flue gas loss, you need:

1) Measurements of flue gas temperature and combustion air temperature. These can be measured using thermocouple type digital indicator. Sometimes these readings are directly available from the installed instrumentation.

2) Flue gas analysis for CO_2 and O_2. These readings can be determined from ORSAT/ FYRITE combustion analysis kit or digital type portable flue gas analyzer. Some plants have continuous gas analyzers in place. By looking at O_2 levels in the flue gas, conclusions can be drawn about the excess air levels.

3) Heating Content in Fuel: This can be determined through lab testing of fuel sample. Typical indicative values are shown below for guidance.

HIGH HEAT VALUE OF VARIOUS FEULS

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 important to note that the foregoing equations require the flue gas analysis to be reported on the dry basis; i.e. the volumes of CO_2 and O_2 are calculated as a percentage of the dry flue gas volume, excluding any water vapor.

Analytical techniques, such as those employing infrared or paramagnetic principles 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.

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 can be used in the ASME equations. This is easily done using correction factors as follows:

%, dry basis = %, wet basis x CF

Approximate values for CF, suitable for quick assessment of boiler efficiency, are

- Natural gas: CF = 1.19

- No. 2 oil: CF = 1.12

- No. 4 oil: CF = 1.10

What can be done to reduce Dry Flue Gas Loss (LDG)?

The following can be concluded from the dry flue gas equations:

1) Reducing the quantity of dry gas (DG) or the excess air levels reduces the dry flue gas loss (LDG). Good burners and precise combustion controls are necessary for good results. Excessive emission of CO, unburned hydrocarbons, and unsafe boiler operation are factors that limit the extent to which excess air can be reduced. For best operating scenarios, ideally O_2 levels in flue gas should be maintained close to 2% and not to exceed 4%.

2) The temperature differential of flue gas temperature (FGT) and combustion air temperature (CAT) should be lowered, or in other words reduce FGT and increase CAT. This is done by preheating the combustion air with a preheater which will raise the CAT, while installing an economizer to recover heat from the flue gases will lower the FGT. Any one or both of these parameters can be varied to reduce the LDG.

(Refer to next section "Combustion Management" for detailed reading).

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2) <u>Loss Due to Moisture from the Combustion of Hydrogen (LH)</u>

The hydrogen component of fuel leaves the boiler as water vapor, taking with it the enthalpy (or heat content) corresponding to its conditions of temperature and pressure. The vapor is a steam at very low pressure, but with a high stack temperature. Most of its enthalpy is in the heat of vaporization. The significant loss is about 11 percent for natural gas and 7 percent for fuel oil.

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

LH, % = [900 x H_2 x (hg – hf)] / HHV

Where:

- H_2 is the weight fraction of hydrogen in the ultimate analysis of the fuel

- HHV is the higher heating value

- hg is the enthalpy of water vapor at 1 psi and the flue gas temperature (FGT) in °F

- hf is the enthalpy of water at the combustion air temperature (CAT) in °F

hg can be determined from steam tables or from the equation:

hg (Btu/lb) = 1055 + (0.467 x FGT)

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

hf (Btu/lb) = CAT - 32

### *What do you need to determine LH?*

Knowing the flue gas temperature (FGT), combustion air temperature (CAT) and fuel analytical data (HHV); LH can be calculated.

What can be done to reduce LH?

Unfortunately, not much can be done to reduce this loss as most of the heat lost is in the heat of vaporization. Measures that reduce the flue gas temperature (FGT) have only a small effect. Only condensing heat exchanger will reduce this loss appreciably. This is discussed later in this course.

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3) <u>Loss Due to Radiation and Convection (LR)</u>

This loss occurs from the external surfaces of an operating boiler. For any boiler at operating temperature, the loss is constant. Expressed as a percentage of the boiler's heat output, the loss increases as boiler output is reduced; hence, operating the boiler at full load lowers the percentage of loss. Since the boiler's surface area relates to its bulk, the relative loss is lower for a larger boiler and higher for a smaller boiler. Instead of making complex calculations, determine the radiation and convection loss using a standard chart available from the American Boiler Manufacturers Association (ABMA). Refer to the figure below for illustration:
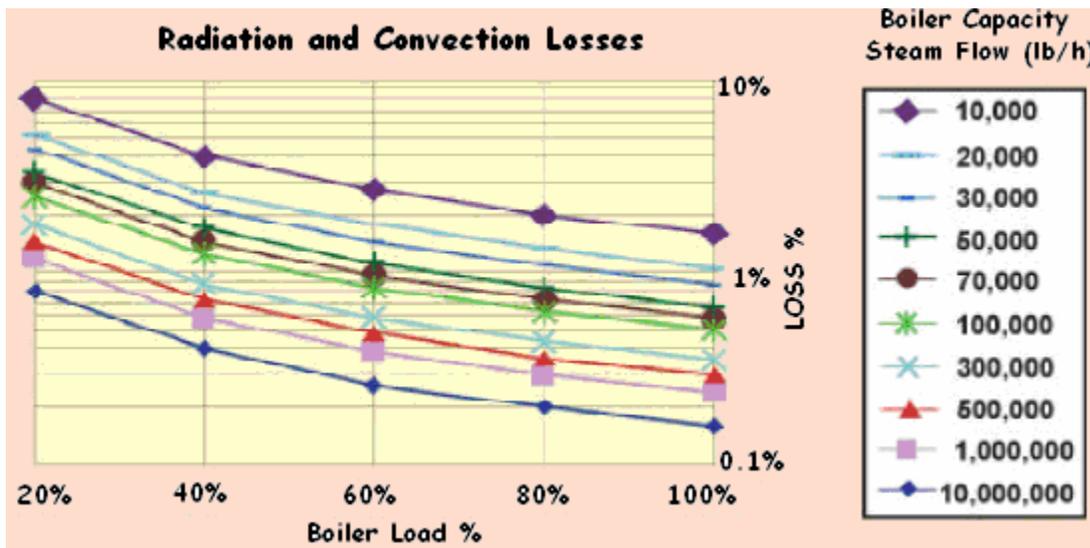
With modern boiler designs, this may represent only 1.5% on the gross calorific value at full rating, but will increase to around 6%, if the boiler operates at only 25 % output. Operating the boiler at full load will optimize this loss.

It is usually more efficient to distribute demand among the available boilers, and on a whole, to operate a fewer number of boilers at higher loads than to operate a large number at low loads.

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4) Losses those are unaccounted for (LUA)

Reasonable assumptions concerning these losses are 0.1 percent for natural-gas-fired boiler systems and 0.2 percent for light oil-fired systems. For heavy oil, a value between 0.3 and 0.5% may be appropriate, to account for fuel heating and, perhaps, atomizing steam.

How to use Heat Loss Data!

Once the 4 losses have been estimated, the operator can make use of this data to compute the boiler efficiency as follows:

Efficiency (E) % = 100 – (LDG + LH + LR + LUA)

Where:

- LDG = Dry flue gas loss
- LH = Moisture from hydrogen loss
- LR = Radiation and convection loss
- LUA = Unaccounted for losses

In general, the combustion efficiency of boiler falls in range of 75 to 85%.

How do you estimate the fuel savings?

All our efforts to reduce energy consumption are expressed in terms "percentage fuel saved". In case the corrective measures are taken to adjust the out-of-range conditions to increase

efficiency from an "as is" situation to a new improved efficiency, the percent savings of fuel consumption can be estimated as:

$$\% \ Fuel \ Savings = \frac{\eta_{new} - \eta_{old}}{\eta_{new}} * 100$$

For an example, if the original fuel cost is $ 500,000 per year when operating at an average efficiency of 70%, raising the efficiency to 80% shall result in fuel savings of 500,000 x (80 – 70)/80 = $ 62,500

It is not possible to capture each and every Btu from combustion in the boiler. The optimum efficiency of boiler lies in range of 75 to 85%.

The above analysis only highlights the part of thermal losses. Majority of energy efficiency improvements are typically found after the generation of steam. There are a lot of other controllable losses, for instance:

1) Boiler blowdown rate

2) Unreturned condensate

3) Deaerator steam vent losses

4) Steam use in end use equipment

5) Identifiable losses in the distribution and use of process steam etc.

This course focuses on these aspects and suggests the possible improvements in three (3) main areas:

1) Combustion Management

2) Makeup, Feedwater, Condensate & Blowdown Management

3) Steam Management (distribution & use)

Part 4 of the course provides a reference checklist and a questionnaire for guiding you with the objective data towards an effective boiler audit study.

PART 1   COMBUSTION EFFICIENCY

The combustion efficiency test is your primary tool for monitoring boiler efficiency. A visual (opacity) technique to check change in flame shape, length, color, noise and smoke characteristics is the first early indicators of potential combustion related problems. But in practice, combustion efficiency is verifiable only with a flue gas analyzer. The stack temperature and flue gas oxygen (or excess air) concentrations are primary indicators of combustion efficiency.

The Logic of Combustion Efficiency Tests

The "combustion efficiency" test determines how completely the fuel is burned, and how effectively the heat of the combustion products is transferred to the steam or water.

Your boiler burns fuel efficiently if it satisfies these conditions:

- It burns the fuel completely;

- It uses as little excess air as possible to do it;

- It extracts as much heat as possible from the combustion gases.

The combustion efficiency test analyzes the flue gases to tell how well the boiler meets these conditions. The test is essentially a test for excess air, combined with a flue gas temperature measurement.

Excess Air

The only purpose of bringing air into the boiler is to provide oxygen for combustion. Bringing in too much air reduces efficiency because the excess air absorbs some of the heat of combustion, and because it reduces the temperature of the combustion gases, which reduces heat transfer. The temperature of the flue gas indicates how much energy is being thrown away to the atmosphere.

There is theoretical or stoichiometric amount of air required for complete combustion of fuel. In practice, combustion conditions are never ideal, and additional or "excess" air must be supplied to completely burn the fuel. When the air falls below the stoichiometric value, there is some fuel that is not burned completely. This partially burned fuel creates smoke, leaves deposits on firesides, and creates environmental problems. Unburned fuel may also represent a significant waste of energy. The amount of waste depends on the energy content of the unburned fuel

components. For example, the unburned components of heavy oil are mostly organic compounds that have high energy content. On the other hand, the unburned components of coal may consist largely of foreign matter that has much lower energy content than coal itself. One source estimates that each 0.1 percent of unburned combustibles in flue gas typically represents between 0.3 and 0.6 percent of the energy content of the fuel. This waste of energy is not measured by analyzing flue gas oxygen or carbon dioxide concentrations. The simplest way of determining the O_2 and CO_2 is to make an ORSAT or FYRITE gas absorbing test kits.

Excess Air V/s Boiler Efficiency

The table below relates the O_2 levels to the excess air and combustion efficiency when seen together with stack temperatures.

Combustion Efficiency for Natural Gas						
		Combustion Efficiency				
Excess %		Flue gas temperature less combustion air temp, °F				
Air	Oxygen	200	300	400	500	600
9.5	2.0	85.4	83.1	80.8	78.4	76.0
15.0	3.0	85.2	82.8	80.4	77.9	75.4
28.1	5.0	84.7	82.1	79.5	76.7	74.0
44.9	7.0	84.1	81.2	78.2	75.2	72.1
81.6	10.0	82.8	79.3	75.6	71.9	68.2

Assumes complete combustion with no water vapor in the combustion air.

On well-designed natural gas-fired systems, an excess air level of 10% is attainable and for fuel oil system 15% is a reasonable figure.

An often stated rule of thumb is that 100% excess air reduces the boiler efficiency by 5% or boiler efficiency can be increased by 1% for each 15% reduction in excess air.

Example: A boiler consumes 55 MMBtu per hour of natural gas while producing 5 lb/hr of 150 psig steam. Stack gas measurements indicate an O_2 level of 7% corresponding to an excess air level of 44.9% and with a flue gas less combustion air temperature of 400°F. Estimate annual savings, if the boiler tune-up results in O_2 level of 2% corresponding to an excess air level of 9.5% and with a flue gas less combustion air temperature of 300°F. Assume that boiler operates 8,000 hours per annum and the average steam value is $ 5.0/MMBtu.

Solution

The cost savings shall be provided by equation:

Cost Savings = Fuel Consumption x (1 – Eff. $_{Initial}$ /Eff. $_{Tune\ up}$) x steam cost

From the table, the initial boiler combustion efficiency is 78.2% and after tune-up the boiler combustion efficiency increases to 83.1%. Therefore:

Cost Savings = 55 x (1 – 78.2/83.1) x 5 = $ 16.2 per hour

Or the cost savings will be $129,600 per annum for 8,000 hours of operation per year.

Optimum Excess Air

No boiler is capable of burning fuel without some amount of excess air, although the percentage of excess air may be small. The table below gives the theoretical amount of air required for combustion of various types of fuel.

Fuel Type	Minimum	+ Excess recommended	= Total O2
Natural Gas	0.5 – 3.0%	0.5 – 2.0%	1.0 – 5.0%
Fuel Oils	2.0 – 4.0 %	0.5 – 2.0%	2.5 – 6.0%
Pulverized Coal	3.0 – 6.0 %	0.5 – 2.0%	3.5 – 8.0%
Coal Stoker	4.0 – 8.0%	0.5 – 2.0%	4.5 – 10.0%

When in doubt, use 10-15% excess air corresponding to O_2 levels of 2 to 4% (unless the operating manual of your boiler states otherwise)

Excess air is required in all practical cases to ensure complete combustion and to allow for the "normal variations in combustion" (refer below).

1) The density of air changes with temperature and pressure, for instance, if pressure is fixed, the mass of air flowing will decrease when the temperature increases. The variations in the ambient temperature and humidity could easily change the air flow from excess air into deficient air or too much excess air.

2) In addition, other variations, such as fuel rate, could easily make effect on the air consumed and cause deficient air at some point. The excess air offers a cushion to allow variations in air conditions without affecting boiler efficiency significantly. The cushion air

is not important when the boiler burner controls are sensitive enough to respond to the varying conditions.

3) Note that the amount of excess air is greatly dependent on the type of fuel and the type of burner. New technology burners such as low NOx burner or spud type burner require minimum excess percent oxygen to as low as 0.5 to 1%. For light oil applications, pressure atomized burners will use as little as 2% minimum excess percent oxygen.

Combustion Efficiency Indicators

1) As a rule, the most efficient and cost-effective use of fuel takes place when the CO_2 concentration in the exhaust is maximized. Theoretically, this occurs when there is just enough O_2 in the supply air to react with all the carbon in the fuel.

2) The absence of any O_2 in the flue gas directly indicates deficient combustion air while presence indicates excess air. Ideally, the O_2 levels shall be maintained close to 2% to 4% (gas & oil).

3) Carbon monoxide (CO) is a sensitive indicator of incomplete combustion; its levels should range from zero to 400 parts per million (ppm) by volume. The presence of a large amount of CO in flue gas is a certain indicator of deficient air.

A general relationship is illustrated in the figure below.
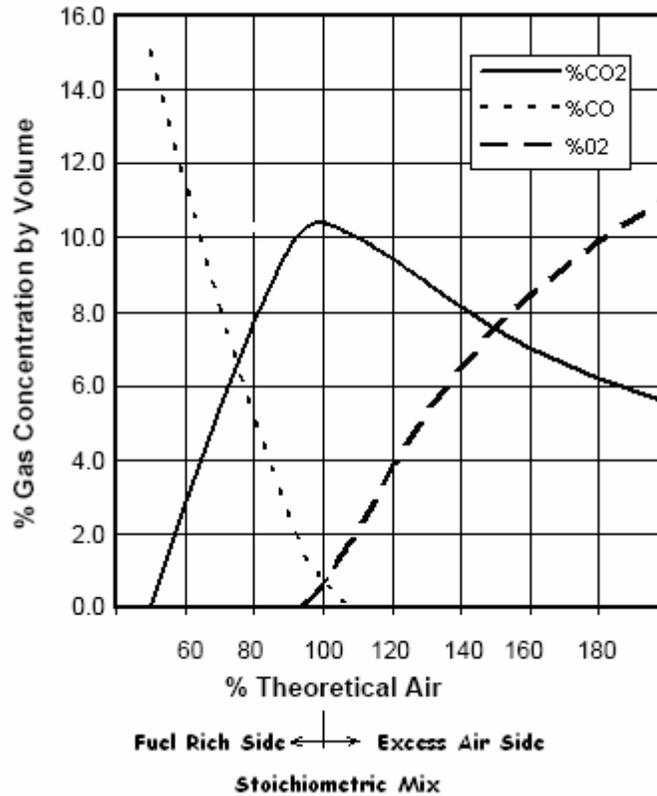
Combustion Gas Concentrations at Percent of the Theoretical Combustion Air

Proceeding from left to right, the curves highlight 4 things:

1) When too little air is supplied to the burner, there is not enough oxygen to completely form CO_2. It suggests incomplete combustion and is characterized by large amount of carbon monoxide (CO) in the stack.

2) As the air level is increased and approaches 100% of the theoretical air, the concentration of CO molecules decreases rapidly and CO_2 reaches a maximum value. This suggests almost complete combustion.

3) Withl more combustion air, excess air begins to dilute the exhaust gases, causing the CO_2 concentration to drop and increase the concentration of O_2. The CO level is practically negligible. A 10 to 15% excess air is desired for safe and reliable operation.

4) The knee of the curve (zero CO), corresponds to the point of maximum furnace efficiency. Carbon monoxide in the flue gas (measured in ppm of CO), stays at a fairly

low level at high excess air, but rises sharply as excess air is reduced below the optimum level.

Flue gas Analysis - What to measure, O_2 or CO_2?

Flue gases contain a composition of oxygen, carbon dioxide, carbon monoxide and sulfur dioxide. All of these gases are easily detectable with modern instrumentation. Oxygen monitoring is the most popular measure as it has a single value relationship with excess air.

The oxygen test is more accurate than the carbon dioxide test. The reason is that the relative change in oxygen is much greater than the relative change in carbon dioxide for a given change in excess air. For example, with No. 2 oil, an increase in excess air from 2% to 10% causes oxygen in the flue gas to increase by a factor of five, a change that you can measure easily. On the other hand, the same increase in excess air causes carbon dioxide to drop by only 10%, a difference that is more difficult to measure accurately.

Another advantage of the oxygen test is that the results are much less sensitive to variations in the chemical composition of the fuel. The amount of carbon dioxide in the flue gas depends on the amount of carbon in the fuel, and the amount of excess air is calculated from this carbon dioxide value. There are large differences in the chemical composition of some fuels, such as industrial by-product gases. All liquid and gas fuels have some variation.

In contrast, the oxygen test provides a direct indication of excess air. Variations in carbon content do not affect the results of the oxygen test at all, and variations in the total energy content of the fuel affect the oxygen content much less than they affect the carbon dioxide content.

Unlike the carbon dioxide test, the oxygen test works only in the region of excess air. There is no oxygen to measure when there is no excess air. This is not a problem in normal testing, because you should always operate boilers with a small amount of excess air.

Additional Tests for Incomplete Combustion

To fine-tune the excess air, you may need an additional test that detects small amounts of incompletely burned combustion products. Two common tests for this purpose are smoke density and carbon monoxide in the flue gas.

Smoke Opacity Test

Before combustion efficiency test equipment became available, the amount of air was adjusted by observing the smoke emerging from the stack. For example, boilers burning heavy oil used the rule that the flue gases should be a "light brown haze." This is no longer satisfactory as a primary test, but it continues to be a useful check. If there is too much smoke when the excess air is set to a reasonably low figure, something is wrong. Therefore, measuring smoke density ("opacity," to be precise) continues to be a valuable diagnostic test.

You can use the smoke density test with heavier grades of oil and with solid fuels. Smoke density is not a reliable indicator with gaseous fuels and with light oils. The unburned residue of these fuels is not visible unless air is very deficient.

Carbon Monoxide Test

The carbon monoxide content of flue gas is a good indicator of incomplete combustion with all types of fuels, as long as they contain carbon. Carbon monoxide in the flue is minimal with ordinary amounts of excess air, but it rises abruptly as soon as fuel combustion starts to be incomplete. This makes it an excellent indicator when making your final adjustments of the air-fuel ratio.

An excessive level of carbon monoxide that occurs in the normal region of the air-fuel ratio indicates trouble within the boiler. Carbon monoxide rises excessively if any defect in the boiler causes incomplete combustion, even with excess air. This makes carbon monoxide testing an excellent tool for discovering combustion problems, especially if it is used in combination with oxygen testing. For example, the carbon monoxide test might reveal a fouled burner. It might also point toward a more subtle problem, such as a poor match of the burner assembly to the firebox, causing a portion of the flame to strike a surrounding surface. (Cooling the flame interrupts the combustion process, leaving carbon monoxide and other intermediate products of combustion in the flue gases.)

Carbon monoxide also forms if there is a great excess of air. This is not a matter of practical significance. Once you set the air-fuel ratio properly, the carbon monoxide content falls into the proper range if there are no other problems.

Approach to Optimum Combustion Control

Usually the cause of excessive or deficient combustion is:

1) The Draft

2) Proper Air-Fuel Mix

Draft Control

The major cause of boiler losses, both avoidable and unavoidable, is the boiler draft. Poor draft conditions alters the flame pattern thus inhibiting the fuel from burning properly and changing the air-fuel ratio.

- Insufficient draft prevents adequate air supply for the combustion process and results in smoky, incomplete combustion.

- Excessive draft allows increased volume of air into the boiler furnace. The larger amount of flue gas moves quickly through the boiler, allowing less time for heat transfer to the waterside. The result is that the exit temperature rises, and this along with larger volume of flue gas leaving the stack, contributes to the maximum heat loss.

Ideally the draft conditions which allow the boiler to operate at 2% to 4% oxygen maintain the maximum combustion efficiency.

If the boiler does not have a forced draft system, excess combustion air cannot be easily or properly controlled. Strong consideration should be given to installing a forced draft system under this situation. Even with a forced draft system, it still may not be feasible to closely regulate the amount of excess air because of burners that require proper air-fuel mix.

If you are unable to maintain the CO_2 levels $\geq$ 12%, it indicates a worn out burner or problem with the furnace draft. In these situations, the manufacturer's representative should be consulted to discuss upgrading the controls and equipment.
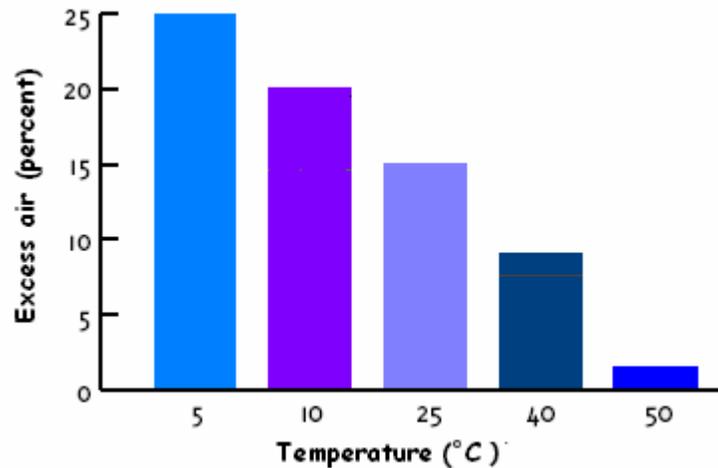

Air-Fuel Ratio

The efficiency of the boiler depends on the ability of the burner to provide the proper air to fuel mixture throughout the firing rate, day in and day out.

The density of air and gaseous fuels changes with temperature and pressure, a fact that must be taken into account in controlling the air-to-fuel ratio. For example, if pressure is fixed, the mass of air flowing in a duct will decrease when the temperature increases. The controls should therefore compensate for seasonal temperature variations and, optimally, for day and night

variations too (especially during the spring and fall when daily temperature variations are substantial).

The figure below shows that the effect of air temperature on excess air in the flue gas can be dramatic.

Effects of Air Temperature on Excess Air Level

Usually the cause of improper Air-Fuel ratio is due to inadequate tolerance of the burner controls, a faulty burner or improper fuel delivery other than draft conditions. Often, the burner cannot provide repeatable air control and sometimes because of controller inconsistency itself, the burners are permanently set up at high excess air levels. The fact is you pay substantial dollars every time you fire the unit.

If you are unable to maintain the CO levels $\leq$ 400 ppm, it indicates the poor mixing of fuel and air at the burner. Poor oil fires can result from improper viscosity, worn tips, carbonization of burner nozzle and deterioration of diffusers or spinner plates.

Excess Air Control - Control & Automation

Excess air control (also referred to as O_2 control) is important for optimum combustion and can be achieved by means of adjusting burner airflow to match fuel flow.

Various types of air-fuel combustion controls are utilized for this purpose. A brief description is as follows in order of sophistication and costs:

1) ***On-off and high-low controls:*** The use of on-off and high-low controls is limited to processes that can tolerate cycles of temperature and pressure, such as heating applications.

2) ***Position Proportional Control:*** This type of control also known as mechanical jackshaft control is the simplest type of modulating burner control used in small boilers with a fairly steady load. In these controls same firing rate signal is presented to both the fuel and air control elements and the 'Fuel/Air' ratio is controlled by fixed positioners mounted to the positioning motor, typically a cam device. The play in the jackshaft and linkages needs settings with higher than- necessary excess air to ensure safe operation under all conditions. The range of oxygen control (oxygen trim) is limited. The control response must be very slow to ensure that the burner reaches a steady state before the oxygen trim acts.

3) ***Parallel controls:*** These controls are usually applied to medium-sized boilers equipped with pneumatic controls.

   Separate drives in parallel controls adjust fuel flow and airflow, taking their signal from a master controller. Their performance and operational safety can be improved by adding alarms that indicate if an actuator has slipped or calibration has been lost.

   Also, an additional controller can be added to provide oxygen trim. Parallel controls have similar disadvantages to mechanical jackshaft controls.

4) ***Cross-limiting control:*** These controls are usually applied to larger boilers firing typically above 13,000 lbs/hr steaming capacity and having wide variations in load demands.

   This design can provide very close control of the air/fuel ratio throughout the burner's operating range without creating fuel-rich or air-rich mixtures, normally experienced in position-proportional systems.

   This control measures the flow of air and fuel and adjusts airflow to maintain the optimum value determined during calibration tests. Fuel rich conditions are avoided by a cross-limiting strategy, which uses high and low signal selectors to achieve a lead/lag effect with the airside. This lead/lag effect forces the fuel to lead the air as demand drops, thus creating a lean transition flame on loss of demand, and fuel to lag air on an increase in demand, which again creates a lean transition flame on increased demand.

Operations are safer when airflow cannot drop below the minimum needed for the existing fuel.

The cross-limiting when applied along with parallel control function, trims the fuel/air ratio to the best combustion ratio. This configuration allows a significantly greater number of combustion points on the combustion curve to control the fuel/air ratio.

Oxygen Trim Systems

Every 1% decrease in excess O_2 from the stack, results in as much as ½ % increase in thermal efficiency.

Automation plays vital role in controlling excess air and also benefits in process consistency, flexibility to load demands, ability to monitor, trend and bill the utilities in the process.

When fuel composition is highly variable (such as refinery gas, hog fuel, or multi-fuel boilers), or where steam flows are highly variable, an on-line oxygen analyzer should be considered. The oxygen "trim" system provides feedback to the burner controls to automatically minimize excess combustion air and optimize the air-to-fuel ratio. It increases energy efficiency by one to two percent. For very large boilers, efficiency gains of even 0.1 percent can result in significant annual savings.

The use of O_2 trim, only trims the amount of excess air above that required for complete combustion for a specific furnace design while not creating a fuel-rich furnace/stack environment. The burner design, fuel selection and load swing are all critical factors affecting the decision to O_2 trim in any given boiler.

Unfortunately, high cost of purchasing and installing an oxygen analyzer discourage its use to small or medium boilers. Typically, its use is advantageous in large boilers that use between $100,000 and $1 million worth of fuel annually. But from the point of view of limiting environment emissions and also to satisfy the authority having jurisdiction, it may be appropriate to install oxygen trim for smaller boilers even though the paybacks are little longer.

Efficiency considerations with Fuel Oil and Natural Gas

1) *Fuel oil Pressure and temperature* directly affect the ability of oil to properly atomize and burn completely and efficiently. Changes promote flame failure, fuel-rich combustion, sooting, oil buildup in the furnace, and visible stack emissions. Causes include a dirty

strainer, worn pump, faulty relief valve, or movement in linkage or pressure-regulating valve set point. Oil temperature changes typically are caused by a dirty heat exchanger or a misadjusted or defective temperature control. When oil is burned, an atomizing medium, either air or steam, is needed for proper, efficient combustion. Changes in atomizing media pressure cause sooting, oil buildup in the furnace, or flame failure. Changes result from a regulator or air compressor problem or a dirty oil nozzle.

2) *Gas pressure* is critical to proper burner operation and efficient combustion. Irregular pressure leads to flame failure or high amounts of carbon monoxide. It may even cause over or under firing, affecting the boiler's ability to carry the load. Gas pressure should be constant at steady loads, and should not oscillate during firing rate changes. Usually, pressure varies between low and high fire. Therefore, readings should be compared to those taken at equivalent firing rates to determine if adjustments are needed or a problem exists.

Gas pressure irregularities are typically caused by fluctuations in supply pressure to the boiler regulator or a dirty or defective boiler gas pressure regulator.

It is important to provide automatic burner controls for safe and efficient operation. Improperly set operating controls cause the burner to operate erratically and stress the pressure vessel.

Negative Effects of Improper Combustion

The negative effects of combustion on the environment – particularly greenhouse gas (GHG) emissions; global warming and acid rain are one of the greatest challenges facing the world today. Unburned hydrocarbons, carbon monoxide, carbon dioxide, sulfur oxides & nitrogen oxides are all products of combustion that provide the greatest threat.

Carbon monoxide: Carbon monoxide is a highly toxic gas associated with incomplete combustion.

The CO level in the flue gas depends solely on combustion efficiency and not on the fuel, the burners or the design of the boiler. Inaccuracies on measurements due to stratification might occur with sample type sensors but essentially flue gas CO concentration is unaffected by air infiltration, and thus gives a more certain indication of combustion. Efforts must be made to

minimize its formation. This effort goes hand-in-hand with improving fuel efficiency and reducing soot generation.

Carbon dioxide: The CO_2 content in flue gas reaches to a maximum, approximately at the ideal air/fuel ratio, and falls off both with increasing and with decreasing excess air. Therefore, applying energy efficiency measures that reduce fuel consumption is crucial to reducing CO_2 emissions.

Nitrous & Sulfurous Oxides: SO_2 and NO_x emissions are primarily due to sulfur content of the fuel and combustion reactions of N_2 at high temperatures.

Emissions of SO_2 and NO_x contribute to acid rain and condensation of these products inside the stack may lead to corrosion of chimney.

SO_2 emissions can be controlled by limiting the allowable sulfur content of the fuel and NO_x emissions can be reduced by manipulating the combustion process.

Managing combustion processes better and improving the efficiency of energy use & generation are two of the key strategies for reducing atmospheric emissions.

Keeping boiler clean from soot

Under conditions of incomplete combustion, unburnt carbon particles get deposited in the form of soot on the inside of fire tubes.

Except for natural gas, practically every fuel leaves a certain amount of deposit on the fireside of the tubes. This is called fouling, and it greatly reduces heat transfer efficiency of a boiler.

Tests show that a soot layer just 0.8 mm (0.03 in) thick reduces heat transfer by 9.5 percent and a 4.5 mm (0.18 in.) layer by 69 percent. As the layer of soot builds up, the stack temperature rises by about 100°F for 1mm thick soot coating. For every 40°F rise in stack temperature, boiler efficiency is reduced by 1%. That's a pretty good argument for regular tube cleaning.

In the high temperature zones of a boiler system such as superheater, corrosion spots may occur due to the melting of some of the components of the deposits having a low melting point. Also in the heat recovery system like an economizer or preheater, corrosion due to sufhur trioxide may show up. Periodic off-line cleaning of radiant furnace surfaces, boiler tube banks, economizers and air heaters may be necessary to remove these stubborn deposits.

Large boilers and those burning fuels with a high fouling tendency have strategically located soot blowers as in integral part of the boiler. Soot blowers are machines that mechanically drive bushes or scrapers through the tubes and clean the surfaces while the boiler is operating. These machines, in turn, connect to powerful vacuums that draw the loosened soot from the tubes, simultaneously, leaving the tubes, boiler room and operator completely clean.

Small boilers, including natural gas-fired boilers should be opened regularly for checking the deposition. The cleaning can be handled using portable powerful air motors, which drive flexible shafts fitted with a wide variety of cleaning tools.

RECLAIMING BOILER SYSTEM HEAT LOSSES

Flue Gas

A 40°F reduction in flue gas temperature will improve boiler efficiency by about 1%.

Even in an optimized combustion, good percentage of heat varying from 10 to 25% is lost in flue gases. Typically, the temperature of flue gases leaving the stack range from 350°F to 500°F. Thus, there is an ample opportunity to recover some heat from these gases.

The waste heat recovery equipments such as economizer or preheater can be installed to preheat the boiler feedwater or preheat the combustion air. Economizers typically increase the overall boiler efficiency by 3 to 4%.

Economizers

Economizers capture waste heat from the boiler stack gases and transfer it to the feedwater. This raises the temperature of the feedwater and thus lowering the amount of Btu input.

Economizers can save as much as 1% fuel cost per 10-degree rise in feedwater temperatures and most economizers raise feedwater temperature by at least 20 to 30 degrees. The potential for energy saving depends on the type of boiler installed and the fuel used.

For a typically older shell boiler, with a flue gas exit temperature of 500° F, an economizer could be used to reduce it to 380° F; increasing the feed water temperature by 27° F. Increase in overall thermal efficiency would be in the order of 3%. This is one of the simplest and most economical additions to any boiler installation.

The potential of heat recovery from the flue gases through the use of an economizer may be seen from the following data:

Btu vs. Feedwater Tables

BTU Input Required to Bring Feed Water to Steaming Temperature

Feedwater Temperature (°F)	Boiler Operating Pressure										
	0	25	50	75	100	125	150	175	200	225	250
50	5,766	7,754	8,872	9,692	10,349	10,906	11,414	11,829	12,223	12,585	12,585
100	4,044	6,032	7,150	7,970	8,627	9,184	9,692	10,107	10,501	10,864	10,864
125	3,182	5,170	6,288	7,108	7,765	8,322	8,830	9,245	9,639	10,001	10,001
150	2,319	4,307	5,425	6,245	6,902	7,459	7,967	8,382	8,776	9,139	9,139
175	1,457	3,445	4,563	5,383	6,040	6,597	7,105	7,520	7,914	8,276	8,276
200	591	2,579	3,697	4,517	5,174	5,731	6,239	6,654	7,048	7,410	7,410
212	177	2,165	3,283	4,103	4,760	5,317	5,825	6,240	6,634	6,996	6,996
225		1,706	2,824	3,644	4,301	4,858	5,366	5,781	6,175	6,537	6,537
230		1,519	2,638	3,458	4,114	4,672	5,179	5,595	5,989	6,351	6,351
240		1,188	2,306	3,127	3,783	4,341	4,848	5,264	5,658	6,020	6,020
250		829	1,948	2,768	3,424	3,982	4,489	4,905	5,299	5,661	5,661

Acid Dewpoint Temperature

The waste heat recovery equipment (economizer) results in reduction of stack temperatures. Maximizing economizer output means that the stack temperature should be low as possible. However, it should not be so low that water vapor in the exhaust condenses on the stack walls.

This is important in fuels containing significant sulfur as low temperature can lead to sulfur dew point corrosion.

The products of combustion in exhaust stack contain O_2, CO_2, CO, NO_x, SO_2 and free water. These gases particularly CO_2 and SO_2 can start condensing at temperatures as low as 250°F resulting in the formation of corrosive carbonic acid and sulfuric acid, which can corrode the chimney. The most furnace and boiler manufacturers therefore specify to size the waste heat recovery devices (economizer or preheater) in a way that exhaust temperatures do not fall below 325°F on a conservative side. Also, the location of the economizer in the stack is also critical because stack gases tend to cool as they approach the stack outlet.

Designers must consider potential corrosion problems and provide design adjustments wherever necessary. Two important aspects are:

1) Each fuel has its specific limit of low flue gas temperature, which should be determined individually. The best possible heat recovery using economizers is achieved with boilers operating on natural gas or LPG. The economy of heat recovery is much greater.

2) The flue gas temperatures are lower at lower loads. Economizers must have some form of by-pass control that maintains the flue gas temperature above a preset minimum.

Acid Dewpoint Temperature of Various Fuels

Fuel	Acid Dewpoint Temperature (°F)	Minimum Allowable Stack Temperature (°F)	Minimum Allowable Feed water Inlet Temperature (°F)
Natural Gas	150	250	210
#2 Oil	180	275	210
Low Sulfur Oil	200	300	220

Condensing Flue Gases

To overcome the concerns of acid dewpoint in conventional economizers, the condensing economizers can be used. Here water is sprayed directly into the flue gas, which cools the flue gas below the dewpoint. This improves the effectiveness of reclaiming both the sensible heat

from the flue gas and latent heat from the moisture that condenses. The operation is like a cooling tower working in reverse. Hot flue gas is cooled and the heat recovered is used to provide a water source, as opposed to the cooling tower where air is heated and the hot water stream is cooled. The benefits are as follows::

1) The resulting hot water can be used as feedwater or used in the process areas after treatment to neutralize its corrosion potential. In some cases, where natural gas is used, the water can be used directly in the process.

2) For a modern 3-pass shell boiler firing natural gas with a flue gas exit temperature of 280°F, a condensing economizer would reduce the exit temperature to 150 $^{\circ}$F thereby increasing thermal efficiency by 5%.

3) With condensing economizers, the overall boiler efficiencies can exceed 90 percent. Heat pumps can complement a system for recovering flue gas heat, further increasing the reclaim efficiency.

4) There is an incidental advantage of direct-contact flue gas condensing: it removes flue gas particles and acid gases such as SO_2 from exhaust.

Combustion Air Preheat

Combustion air preheating is an alternative to feedwater heating. In order to improve thermal efficiency by 1%, the combustion air temperature must be raised by 36° F. Most gas and oil burners used in a boiler plant are not designed for high air preheat temperatures.

Modern burners can withstand much higher combustion air preheat, so it is possible to consider such units as heat exchangers in the exit flue as an alternative to an economizer, when either space or a high feed water return temperature make it viable.

Flue Gas Recirculation

Flue gas recirculation method recycles some of the exhaust gases back to the burner. While the heat content of the exhaust air contributes to heat recovery, the reduced oxygen content of these exhaust gases lowers the flame temperature in the combustion zone, thereby reducing NOx formation. This reduced flame temperature also lowers the heat transfer, potentially limiting the maximum heating capacity of the unit. For example, it would not be unusual for a boiler

retrofitted with flue gas recirculation to see a 10% reduction in maximum steam generating capacity. The advantage lies in the reduced environment emissions.

Insufficient Heat Transfer Surface (Heat Recuperation)

A three-pass fire-tube boiler will have an exhaust temperature of about 450°F at high fire; whereas a four-pass wet back fire-tube could have an exhaust temperature of only 350°F. Few installations could have the stack temperatures much above these figures.

What does all this mean?

1) Insufficient heating surface of the boiler

2) Lower number of boiler passes

The heating surface (sq-ft per boiler hp*) represents how hard the vessel is working. For fire-tube boilers, 5 sq-ft heating surface per horsepower* is considered to be an optimum design. Inadequate surface area will mean higher losses.

The number of boiler passes simply represents the number of times the hot combustion gas travels across the boiler (heat exchanger). A boiler with two passes provides two opportunities for the hot gasses to exchange heat to the water in the boiler. A 4-pass unit provides four opportunities for heat transfer. The stack temperature of a 4-pass boiler will be lower than the stack temperature of a similar size 2- or 3-pass boiler operating under similar conditions. Obviously, the 4-pass will have higher efficiencies and lower fuel costs.

What should be done?

For new purchases, it is prudent to invest on a product that meets the best efficiency standards and do not require any waste heat recovery add-ons. A high efficiency boiler must be built with an optimum cross sectional heating area ensuring proper flue gas velocity and heat transfer.

For existing installations where, the flue gas temperatures exceed a limit of approximately 230°F for natural gas and 270°F for fuel oil, heat recuperation is an option. Experience shows that additional heat transfer surface in the form of air preheaters or economizer can get a payout of one to two years for most boilers when flue gas temperature exceeds 425°F.

 [* Horse Power is a unit of measurement of the ability of a boiler to evaporate water, usually given as the ability to evaporate 34 lb (15.6 kg) of water per hour, into dry saturated steam at 212°F (100°C)]

Heat cascading

Plants with several heating needs provide an excellent opportunity to improve their overall energy efficiency with heat cascading. The heat cascading implies that the heat exhausted from one part of the process can be used to heat another. While the high-grade heat supplied from fuel should be directed to the process needing the highest temperature, its exhaust heat should be used in lower temperature applications. The heat finally exhausted should be at the lowest temperature that can be economically achieved.

Examples:

- Air or gas exhausted from a high temperature process is passed through a waste heat boiler to generate low-pressure steam or hot water for space heating or hot service water.

- Waste heat in industrial plants can also be used to operate a vapor absorption machine for cooling purposes.

Summarizing:

1. Substantial energy losses in the boiler are caused by waste heat literally going "up the chimney," incomplete combustion and heat loss from exterior boiler surfaces. Together, these losses can reach 30% of the fuel input, thus hurting efficiency.

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

3. The three basic strategies for minimizing stack gas heat loss are: (1) Minimize excess air in combustion, (2) Keep heat transfer surfaces clean, (3) Add flue gas heat recovery equipment where justified.

4. It is important that the combustion air be delivered in just the amount needed for complete combustion. An important point to note here is that the air/fuel ratio is based on mass, not volume. The mass of air supplied to the mass of fuel being used (e.g. on a lb to lb basis) must be controlled.

5. As a rule of thumb, boiler efficiency increases about 1% for each 15% reduction in excess air, 1.3% reduction in oxygen, or 40°F reduction of stack gas temperature.

6. Economizers can save as much as 1% fuel cost per 10-degree rise in feedwater temperatures and most economizers raise feedwater temperature by at least 20 to 30 degrees.

7. A typical condition for efficient boiler operation is to minimize excess air level to 10 to 20% corresponding to O_2 level of 2 to 4% and CO_2 level of resulting in 13 to14%.

8. It is estimated that 3 mm of soot can cause an increase in fuel consumption by 2.5%.

9. As a rule of thumb, reducing O_2 by 1%, say from 5 percent to 4 percent in the flue gas, increases boiler efficiency by about 0.5 percent.

Limitations of Combustion Efficiency Test

The combustion efficiency does not account for:

1) Standby losses (- a combustion efficiency test is performed under a steady load, therefore, the combustion efficiency test does not reveal standby losses which occur between firing intervals).

2) Heat loss from the surface of the boiler to the surrounding space (- as a practical matter, you cannot measure this loss. Typical estimates state that the loss from surface radiation is about two percent of the boiler's full load energy consumption).

3) Blowdown loss (- the amount of energy wasted by blowdown varies over a wide range).

4) Soot blower steam (- the amount of steam used by soot blowers is a variable that depends on the type of fuel and the judgment).

5) Auxiliary equipment energy consumption (- the energy use by auxiliary equipment such as burners, fans, and fuel pumps).

Fortunately, you don't need to measure all these if the objective is to tune up the plant's efficiency.

PART-2   MAKEUP, FEEDWATER & BLOWDOWN MANAGEMENT

Scale deposits and corrosion are the two most important adverse effects of feedwater impurities which influence the energy consumption.

The makeup water, depending on its source, may contain large amount of soluble impurities. Under heat and pressure most of these soluble components come out of solution as particulate solids; sometimes in crystallized forms and other times as amorphous particles. When solubility of a specific component in water is exceeded, scale or deposits develop.

Makeup water also contains considerable amounts of dissolved oxygen, which is a prime cause of corrosion. The high heat intensity of the evaporation accelerates the oxidation, scaling and corrosion process. The pitting corrosion leads to boiler tube failures and might damage the downstream equipment. Generally the higher the makeup water, the higher will be the impurities and the dissolved oxygen loading.

SCALE DEPOSITS

The presence of hardness salts in boiler water leads to formation of deposits, technically known as 'scale', which has a very low thermal conductivity and impacts the evaporation rates.

The most important salts contained in water, which influence the formation of deposits in the boilers, are the salts of calcium and magnesium, which are known as hardness salts. Calcium and magnesium bicarbonate dissolve in water to form an alkaline solution and these salts are known as 'alkaline' hardness. They decompose upon heating, releasing carbon dioxide and forming a soft sludge, which settles out. These are called 'temporary' hardness-hardness that can be removed by boiling.

When calcium and magnesium sulfates, chlorides and nitrates are dissolved in water, they are chemically neutral and are known as 'non-alkaline' hardness. These are called permanent hardness and form hard scales on boiler surfaces, which are difficult to remove. Non-alkalinity hardness chemicals fall out the solution due to reduction in solubility as the temperature rises, by concentration due to evaporation which takes place within the boiler, or by chemical change to a less soluble compound.

The key effects of scale deposits on boiler operation are:

1) Scale deposits act as insulators and slow heat transfer. Large amounts of deposits throughout the boiler could reduce the heat transfer enough to reduce the boiler efficiency significantly.

2) Scale in addition to its high insulating value; progressively narrows pipe internal diameters, roughen tube surfaces and impede proper flow.

3) The insulating effect of scale deposits causes the boiler metal temperature to rise, which increases the flue gas temperature. In extreme cases, the tubes fail from overheating.

4) Scale causes fuel wastage typically up to 2% for water-tube boilers and up to 5% in fire-tube boilers.

As a rule of thumb, one millimeter of scale build-up can increase fuel consumption by 2%.

The figures below bring out the importance of the scales and its influence on energy consumption.

Effect of Scale Thickness on Heat Transfer

(Scale Thickness vs. Heat Transfer Loss Multiplier)
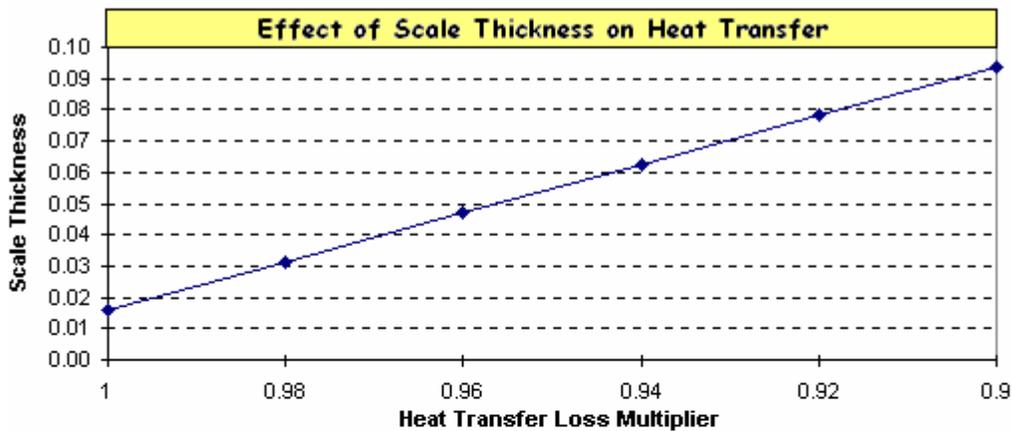
| Energy Loss due to Scale Deposits			
	Fuel Loss, % of Total Use		
Scale Thickness, inches	Scale Type		
	"Normal"	High Iron	Iron Plus Silica
1/64	1.0	1.6	3.5
1/32	2.0	3.1	7.0
3/64	3.0	4.7	–
1/16	3.9	6.2	–

Example: *Consider a 10,000 lb/hr boiler operating at 150 psig and uses a 100,000 million Btus of fuel while operating at 8,000 hours per annum. Assuming the fuel rate of $3 per million Btu, how much will be the dollar loss if scales build up of 1/32" is allowed.*

From the table above 1/32" thickness of scale will correspond to 2% of fuel loss.

*Therefore Annual Operating Cost Increase = 100,000 * 3 * 0.02 = $ 6000*

The result of tests made by University of Illinois and the U.S. Bureau of Standards on the effects of boiler scale on the fuel costs is depicted in the figure below:
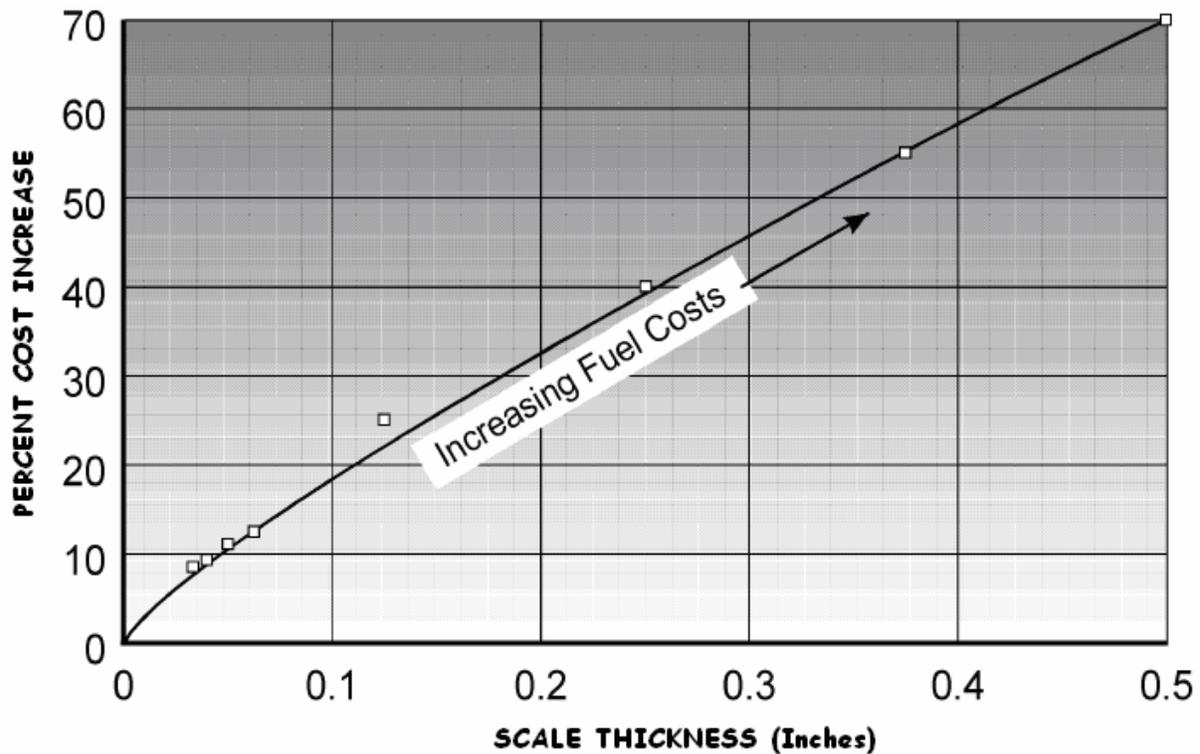
This brings out the importance of the scales and its influence on energy conservation in a boiler. It is intuitively obvious that the presence of any scale in a boiler is undesirable. The best way to deal with scale is not to let it form in the first place. Scale formation is prevented by:

- Pretreatment of boiler make-up water (using water softeners, demineralizers, and reverse osmosis) to remove the scale forming minerals before they enter the system.

- Chemical injection into the boiler feedwater for instance acid or phosphates to keep the common scale forming materials in dissolved form.

- Adopting proper boiler blowdown practices: Limit the concentration of scale forming materials by controlling cycles of concentration. Some water is purposely drained off (blow down) to prevent minerals built up. A cycle of concentration is the ratio of the make-up rate to the blow down rate.

Monitoring Scale Formation

Scale formation can be monitored by direct or indirect methods.

1) The direct method involves visual inspections of boiler tubes when the unit is shut down for maintenance. Scale removal can be achieved by mechanical means or acid cleaning. If scale is present, consult with your local water treatment specialist and consider modifying your feedwater treatment or chemical additives schedule.

2) An indirect indicator of scale formation is flue gas temperature. An upward trend in flue gas temperatures over weeks or months usually indicates that a deposit has built up on either the fireside or waterside of boiler heat-exchange surfaces. The boiler should be inspected promptly.

Water Treatment Approaches

There are two types of boiler water treatment methods: Internal water treatment and External water treatment and are discussed below:

Internal Water Treatment

Internal boiler water treatment is usually in form of chemical dosage/injection to prevent the potential problems of scale by converting the scale-forming compounds to free-flowing sludge's, which can be removed by blowdown. The corrosion inhibitors in form of neutralizing or filming amines protect the boiler internals from corrosion.

The internal treatment alone is not recommended and is usually accompanied along with the external treatment.

Where feedwater is low in hardness salts, the internal treatment alone might be OK, but for high pressure boilers and those requiring large quantity of makeup water, the internal treatment

alone may not be economical. The blowdown rate in such situations will be very high and these become uneconomical from heat, water and chemical loss considerations.

The common internal treatment chemicals are:

- Polyphosphates and Sodium Meta Phosphate for scale control

- Sodium Sulfite, Hydroquinone Hydrazine, Diethylhydroxyamine (DEHA), Methyl ethyl ketoxime for dissolved oxygen

- Neutralizing and filming amines for corrosion control due to CO_2.

Internal treatment alone is not recommended.

External Water Treatment

The first stage of treatment is to remove hardness salt and total dissolved solids (TDS). Removal of only hardness salts is called softening, while total removal of salts from solution is called demineralization. A brief overview is as follows:

Water Softener: Where hardness alone is a limiting factor, the most common method is the water softener. In softening process, a cation-exchange zeolite resin exchanges all calcium and magnesium ions (hardness ions) for sodium ions and reduces hardness to nearly zero. Sodium zeolite softening has no effect on dissolved solids, alkalinity or silica. Other softening techniques include:

- *Cold lime softening:* is performed at ambient temperatures by the addition of hydrated lime to the water being treated. Maintaining proper control of the lime feed reduces calcium hardness to 35 to 50 ppm as calcium carbonate.

- *Hot lime softening* is carried out in a pressure vessel at temperatures between 227 and 240°F. At these temperatures, hot process softening reactions go essentially to completion.

- *Hot lime soda:* Adding soda with ash to the hot lime process increases the effectiveness of the softening process further. It reduces hardness to about 8 ppm and magnesium content to 2 to 5 ppm.

Dealkalization: Where hardness and alkalinity is the limiting factor, split-stream dealkalization or chloride dealkalization is used. Split- stream dealkalization employs two cation exchange units operated in parallel; one is conventional sodium zeolite softener regenerated with salt, and the other contains the same type of resin but is regenerated with acid. A portion of makeup water passes through the sodium zeolite to remove hardness by exchanging calcium and magnesium for sodium, and the remainder goes through acidified zeolite for removal of hardness and alkalinity. Adjusting the ratio of sodium zeolite effluent to hydrogen (acid) zeolite effluent obtains any desired alkalinity reduction. Split-stream dealkalization lowers the hardness level to nearly zero, reduces alkalinity and removes dissolved solids to the extent of alkalinity reduction.

Chloride dealkalization uses two ion exchange units operated in series. The first is a conventional sodium zeolite softener containing cation exchange resin, and the second is a dealkalization unit containing anion exchange resin. Both units are regenerated with salt, which eliminates the handling of acids required in the split-stream method. The sodium zeolite is used to remove hardness and the anion unit exchanges bicarbonate and sulfate for chloride. Alkalinity of the final effluent is reduced to nearly zero.

The chloride processes do not remove dissolved solids or silica. All anions including bicarbonate and sulfate are exchanged; therefore, high-sulfate waters are costly to treat by chloride dealkalization. Because this process removes nearly all alkalinity, caustic soda is added to the system to obtain the necessary hydroxide alkalinity in the boiler water.

Desilicization: If silica is the limiting feedwater constituent, it is removed by a strongly basic anion exchange resin regenerated with caustic soda. Two systems are used; the choice depends on whether a reduction in the dissolved solids level also is required.

1) Desilicization uses a convention sodium zeolite softener, followed by a strongly basic anion resin unit. Hardness is reduced in the cation unit and all anions and silica are reduced to nearly zero.

2) A cation exchanger in the hydrogen form (regenerated with acid) is followed by a strong base anion exchanger (regenerated with caustic soda). All cations and anions are exchanged for hydrogen and hydroxide respectively, thus removing all dissolved solids, including silica, to nearly zero. Demineralization results in a very pure effluent but the cost of operation is high and may not be justified for low to moderate pressure boilers.

Desilicization using membrane systems is often preferred where dissolved ion concentrations are high because of operating cost considerations. High silicate levels are difficult and may require co-precipitation with other ions or high temperature caustic regeneration of ion exchange system.

Demineralization: Where dissolved solids (TDS) is a limiting feedwater constituent, demineralization approach is followed. Demineralizers consist of ion exchange resin columns, a strong cation unit, and strong anion unit. Hydrogen cation exchange converts dissolved salts to their corresponding acid forms, which are removed by the basic anion exchanger. Demineralization removes all inorganic salts by ion exchange. Demineralizer water approaches distilled water in purity but the cost of operation is high and may not be justified for low to moderate pressure boilers. The other methods for removal of total dissolved solids include simple sedimentation in settling tanks or settling in clarifiers with aid of coagulants and flocculants. Pressure sand filters, with spray aeration to remove carbon dioxide and iron, may be used to remove metal salts from bore well water.

Caution: Before any of these external treatments are used, it is necessary to remove suspended solids and color from the raw water, because these may foul the resins used in the treatment sections.

FEEDWATER MANANGEMENT

Boiler feedwater consists of returned condensate plus the makeup water to satisfy steam demands.

Condensate water, if not contaminated by the process is very pure, and when returned back to the boiler is the most attractive method of improving the boiler water quality and plant's energy efficiency.

Makeup water usually contributes to most of the contaminants. Therefore, the more the condensate water, the better will the feedwater quality be.

Condensate recovery is important to the overall efficiency of a boiler for three main reasons:

1) Condensate is usually hot (130°F to 225°F) compared to the temperature of the makeup water (50°F to 60°F). Losing hot condensate means loosing precious heat energy of

heating makeup water. Recovery of all condensate can improve overall efficiency by up to 10%.

2) Condensate is very high quality water. The more condensate that is returned, the less makeup water will be used. The lesser the makeup water, the lesser will the amount of contaminants be introduced into the boiler system. The lesser the contaminants, the lesser will the need for both external and internal water treatment be. This saves on the volume of water on the account of compensating makeup water and associated cost of treatment/chemicals.

3) The more the condensate recovery, the lesser will the condensate that is discharged into a sewer system be and the lower will the blowdown be. This will reduce the sewer disposal costs.

Condensate recirculation is unsuitable only where there is possibility of condensate being contaminated because of process leaks and direct process contact. The contaminated condensate must be segregated from the pure stream; otherwise it may lead to bigger failures, safety and efficiency issues. As such, it should be avoided.

Heat Content of Condensate

The graph below shows the heat remaining in the condensate at various condensate temperatures, for a steam system operating at 100 psig, with make-up water at 55°F.
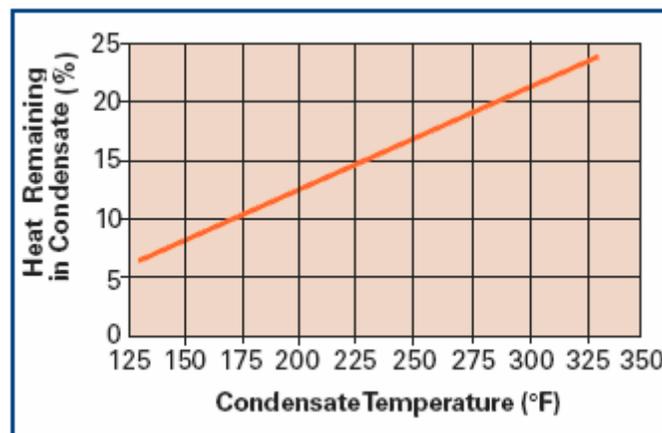
A simple calculation indicates that energy in the condensate can be more than 10% of the total steam energy content of a typical system.

- hc = Enthalpy of condensate at 180°F = 148 Btu/lb

- hm = Enthalpy of makeup water at 55° F = 23 Btu/lb

- hs = Enthalpy of steam at 100 psig = 1189 Btu/lb

Heat remaining in condensate (%) = (hc- hm) / (hs- hm) * 100

= (148 -23) / (1189-23) * 100 = 10.7%

As a rule of thumb, every 10.7°F rise in the feedwater temperature, the fuel saving may be up to 1%.

Energy Savings due to Return Condensate

Example-1

Consider a boiler produces 100,000 lb/hr of steam and operates 8,400 hours per year. Raw make-up water is at 68°F. Currently all condensate is discharged to waste at 194°F. Raw water costs $0.002/gal and effluent treatment costs are $0.001/gal. The boiler is 85% efficient, and uses gas on an interruptible tariff charged at $3.00 per Million Btu. Assuming 75% of condensate is recovered; determine the potential savings value of returning the condensate.

Part 1 - Determine the fuel cost

Each lb of condensate not returned to the boiler feed tank must be replaced by 1 lb of cold make-up water (68°F) that must be heated to the condensate temperature of 194°F. (ΔT = 126°F).

Heat required to increase the temperature of 1lb of cold make-up water by 126°F is given by:

$Q = m \times C_p \times \Delta T$

Where:

- Q = Quantity of energy (Btu/hr)

- m = Mass of the substance (lbs)

- c_p = Specific heat capacity of the substance (Btu/lb °F)

- ΔT = Temperature rise of the substance (°F)

m is unity; ΔT is the difference between the cold water make-up and the temperature of returned condensate; c_p is the specific heat of water at 1 Btu/lb °F.

1 lb x 1 Btu/lb °F x 126°F = 126 Btu/lb

Evaporation rate = 100,000 lb/hr

Condensate return = 100,000 x 75% = 75,000 lb/hr

For a plant in operation 8,400 h/year, the energy required to replace the heat in the make-up water   is:
75,000 lb/h x 126 Btu/lb x 8,400 h/year = 79,380 Million Btu/year

If the average boiler efficiency is 85%, the energy supplied to heat the make-up water is:

79,380 million Btu/year / 0.85 = 93,388 million Btu/year

With a fuel cost of $ 3 per MBtu, the value of the energy in the condensate is: Annual fuel savings = 93,388 million Btu/year x $3 = $280,164 per annum

Part 2 - Determine the water cost

Water is sold by volume, and the density of water at normal ambient temperature is about 8.33 lb/gallon. The total amount of water required in one year replacing non-returned condensate is therefore:

8,400 hr * 75,000 lb/hr / 8.33 lb/gallon = 75,630,252 gallons/year

At water cost of $ 0.002 per gallon, the annual water cost is = 75,630,252 * 0.002 = $151,260 per year

Part 3 - Determine the effluent cost

The condensate that was not recovered would have to be discharged to waste, and may also be charged by the water authority.

Total amount of water to waste in one year also equals 75,630,252 gallons/year

At effluent costs of $ 0.001 per gallon, the annual water cost is = 75,630,252 * 0.001 = $75,630 per year.

Part 4 – Potential Value of Condensate Return

The total savings due to 75% condensate return are therefore:

Fuel Savings = $280,164 per annum

Water Savings = $151,260 per year

Effluent Savings = $75,630 per year

Total Savings = $507,054 per year

On this basis, it follows that for each 1% of condensate returned per 100,000 lb/hr evaporated as in the examples, a saving of 1% of each of the values shown in Part 4 would be possible.

This calculation above does not include a value for savings due to reduction in the costs of water treatment, chemicals and reduced blowdown, which will further increase the savings. When assessing condensate management for a specific project, such savings must also be determined and included.

Example-2

Consider a boiler producing steam @ 50,000 lb/hr and is returning 25,000 lb/hr of condensate at 180°F. The energy audit results for the plant indicate that by upgrading the steam traps and distribution network, an additional 10,000 lb/hr of condensate can be recovered. This involves an investment of $100,000. Determine simple payback for implementing this decision.

Assume the system operates 8,000 hours annually with an average boiler efficiency of 82%, and the average makeup water temperature of 55°F. The water and sewage costs for the plant are $0.002/gal, and the water treatment chemical cost is $0.002/gal.

Consider average fuel cost of $3.00 per Million Btu and for conservatism assume 12% of flash steam loss, when saturated condensate is reduced to lower pressure.

Annual Fuel Savings:

(1 – Flash Steam Fraction) x (Additional Condensate Recovered in lbs/hr) x Annual Operating Hours x (Makeup Water Temperature rise in °F) x (Fuel Cost in $/Btu)) ÷ Boiler Efficiency

$(1 - 0.12) \times 10,000 \times 8,000 \times (180 - 55) \times \$3.00 / (0.82 \times 10^6)$

= $32,195

Annual Water & Sewage:

(1 – Flash Steam Fraction) x (Additional Condensate Recovered in lbs/hr) x Annual Operating Hours x (Total Water Costs in $/gal) ÷ (Water Density in lbs/gal)

(1 - 0.12) x 10,000 x 8,000 x $0.002 / 8.33

= $16,880

Annual Chemicals Savings:

(1 – Flash Steam Fraction) x (Additional Condensate Recovered in lbs/hr) x Annual Operating Hours x (Total Water Costs in $/gal) ÷ (Water Density in lbs/gal)

(1 - 0.12) x 10,000 x 8,000 x $0.002 / 8.33

= $16,880

Total Annual Savings Due to Return of an Additional 10,000 lbs/hr of Condensate

= $33,760 + $16,880 +$16,880 = $65,955

Simple Payback period = Investment / Savings = 100,000 / 65,955 = 1.52 years or ~ 18 months

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Flash Steam Recovery

Flash steam is produced when condensate at a high pressure is released to a lower pressure and can be used for low pressure heating. The flash steam quantity can be calculated by the following relation with the help of steam tables:

Flash Steam Available % = (S1- S2) / L2

Where:

- S1 is the sensible heat of higher pressure condensate

- S2 is the sensible heat of the steam at lower pressure (at which it has been flashed)

- L2 is the latent heat of the flash steam (at lower pressure)

Flash steam from the condensate can be separated in equipment called the flash vessel. This is a vertical vessel with the diameter of the vessel is such that a considerable drop in velocity allows the condensate to fall to the bottom of the vessel from where it is drained out by a steam trap. Flash steam itself rises to leave the vessel at the top.

The steam generated can be used on low-pressure applications like direct injection and can replace an equal quantity of live steam that would be otherwise required. *The higher the steam pressure and the lower the pressure of flash steam, the greater the quantity of flash steam that can be generated.* Generally, the simplest method of using flash steam is to flash from a machine/equipment at a higher pressure to a machine/equipment at a lower pressure, thereby augmenting steam supply to the low pressure equipment (from the need of steam regularly through a reducing valve).

In general, a flash system should run at a lowest possible pressure so that the maximum amount of flash is available and the back pressure on the high pressure systems is kept as low as possible.

Estimating Condensate Recovery

As a rule, the ideal percent condensate return can be easily estimated based on silica or neutralized conductivity tests which provide a reasonable accurate estimate.

Consider a test on a small boiler using softened water, which indicates the following analysis:

Location	Silica, ppm	Conductivity, micromhos (neutralized)
Boiler makeup	40	525
Condensate	3	45
Feedwater	20	265

Then based on silica results, the following equations can be used:

20 VF = 40 VM + 3 VC…………..Equation 1

VF = VM + VC…………………….Equation 2

Where:

- VF = Volume of feedwater

- VM = volume of makeup water

- VC = Volume of condensate

VC is estimated by solving Equations 1 and 2 (multiply Equation 2 with 3 and subtract from Equation 1)

17 VF = 37 VM

From which:

VM = 17*100/37 = 45.94%

VC = 100-45.94 or 54.06%

Therefore in the scenario above, the ideal 'condensate- makeup' split is roughly 54% condensate and 46% makeup water.

If all the condensate streams return back to the boiler and nothing escapes the system, then the makeup water topping up is minimum. The process is essentially a "closed loop" process.

Most often, however, some water or steam escapes from the loop and makeup is necessary in order to maintain the water inventory. In the extreme case where no condensate is returned to the boiler, the process becomes a "once through" system and makeup water rate matches steam flow rate.

Generally the higher the makeup water, the higher will the impurities be and the higher will the water treatment costs be. Closed loop process requiring minimum makeup water is the best way to ensure optimum level of water quality.

Condensate Water Treatment and Monitoring

Condensate water is very important to your facility and ignoring this unseen closed loop component will soon cause failures, thereby costing bottom-line dollars. In general, the condensate is very pure or free of salts but it could be corrosive because it contains dissolved CO_2, and can add dissolved and suspended iron to the feedwater.

Carbonate and bicarbonate alkalinities in the makeup water break down under boiler temperature and pressure to form carbon dioxide (CO_2), which is liberated to the steam. During steam condensation, the carbon dioxide dissolves to form carbonic acid. If untreated, the condensate return piping, valves and tanks experience severe "grooving" corrosion. These products "neutralize" the acidic effects of the hot carbonic acid.

The condensate system does not require elaborate external treatment as with makeup water but soft measures like condensate polishing or conditioning may be required to insure the integrity of the equipment.

The remedies and cautions are as follows:

1) The most common method of dealing with this problem is through the use of neutralizing amines. These chemicals, better known as morpholine and cyclohexylamine neutralize the carbonic acid and increase the pH of the condensate.

2) A filming amine, such as octyldecylamine, provides a non-wettable protective barrier against both carbonic acid and oxygen. These create an oil attractive, water repellent film on metal surfaces which is resistant to both carbon dioxide and oxygen.

Energy Loss due to Improper De-aeration of Boiler Feedwater

Since makeup water contains considerable amounts of dissolved oxygen, corrosion becomes a critical reliability concern because high heat intensity at the boiler tubes accelerates the oxidation process. Therefore, feedwater to the boiler must be made oxygen free.

Also steam with as little as 1% by volume of air in it, can reduce the efficiency of heat transfer by up to 50%. Therefore, attention to the de-aeration process as well as to the proper functioning of air vents is of significant importance.

Deaerator is most commonly used equipment to get rid of dissolved oxygen. Very briefly, the deaeration process uses live steam to bring the feedwater up to approximately 105°C and mechanical agitation to drive off the oxygen from the water. The liberated dissolved oxygen must be continuously removed from the deaerator, and hence, a small amount of purge steam from the deaerator is an accepted industrial norm.

The size of this required purge depends on factors like design capacity, efficiency and oxygen loading on the deaerator unit. Typically, the vent rate is around 0.5 to 1% for smaller, more efficient units and having lower make-up water. High make-up water requires vent rate of over 1%.

Example: A boiler with 100,000 lb/hr capacity vent out 1,000 lb/hr of steam. That amounts to 8 million pounds of steam per year costing $64,000.00 at $8.00 per thousand pounds. Additional venting over and above this 1% can quickly add up to hundreds of thousands of dollars a year.

Dearators must be fitted with auto-controls and safety devices to limit the purge requirement to the required levels. Note that the higher the makeup water, the higher is the dissolved oxygen loading. All efforts to maximize condensate recovery are therefore very important.

In order to minimize oxygen pitting, a volatile oxygen scavenger such as diethylhydroxyamine (DEHA) could be utilized. DEHA provides better results, as it scavenges oxygen and passivates

or coats the condensate system, making it less susceptible to corrosion. Sodium sulfite and Hydrazine are other commonly used chemicals for oxygen scavenging. The latter, however, is carcinogenic and is not generally used in low and medium pressure plants.

BLOWDOWN WATER

When water is converted to steam, the dissolved solids do not travel with the steam, but are left behind in the boiler water. Fresh makeup water enters the boiler to replace the amount lost through steam evaporation. When this new water is converted to steam, more solids are left behind. As steam is continually produced, evaporated, and replaced with new water, the amount of solids in the boiler continues to increase indefinitely until the water is unable to dissolve its own impurities or hold them in solution. These will inevitably collect in the bottom of the boiler in the form of sludge, and are removed by a process known as bottom blowdown.

Cycles of concentration is an indicator of the amount of solids buildup in the water.

For every pound of steam generated, a pound of water must be replaced. The amount of solids in the water will have doubled when the amount of new water that has entered the boiler is equal to the amount of water that was used to originally fill the boiler. When the amount of solids has doubled, there are *2 cycles of concentration in the water.* When the amount of solids has tripled, there are *3 cycles of concentration.*

Effects of Insufficient or Excessive Blowdown

Insufficient blowdown may lead to carryover of boiler water into the steam, or the formation of deposits. Excessive blowdown will waste energy, water, and chemicals. The optimum blowdown rate is determined by various factors including the boiler type, operating pressure, water treatment, and quality of makeup water. Blowdown rates typically range from 4% to 8% of boiler feedwater flow rate, but can be as high as 10% when makeup water has high solids content.

For example, consider a 50,000 lb/hr boiler operating @ 125 psig has a blowdown heat content of 330 Btu/lb. If the continuous blowdown system is set at 5% of the maximum boiler rating, then the blowdown flow would be about 2,500 lb/hr containing 825,000 Btu.

At 80 percent boiler efficiency, this heat requires about 1,050 cu- ft / hr of natural gas, worth about $42,000 per year based on 8,000 hrs of operation per year at $5 per 1,000 cu-ft.

Blowdown Rate & Cycles of Concentration

Blowdown limits the concentration of impurities in the boiler water. A boiler operating on high quality feedwater needs very little blowdown. The purer the feedwater, the lesser is the blowdown required and higher shall be the cycles of concentration. If the feedwater quality is improved so that it is concentrated 6 times rather than 3, the blowdown rate for 100,000 lb/hr steam boiler is reduced from 33.3 to 16.7 percent.

Increasing the cycles of concentration to twice the original value shall cut the blowdown and energy losses in half. One way to maximize the cycles of concentration of the boiler water is by controlling the boiler water at the highest allowable chemistry limits and feeding recommended levels of treatment. The quantity of blowdown can be minimized and the steam purity maintained. In actual practice, a combination of the mechanical heat recovery and chemical treatment is best.

Blowdown Calculations

The quantity of blowdown required to control boiler water solids concentration is calculated by using the following formula:

$$\text{Blowdown (\%)} = \frac{\text{Feedwater TDS} * \text{\% Makeup Water}}{\text{Maximum Permissible TDS in Boiler Water}}$$

If maximum permissible limit of TDS as in a package boiler is 3,000 ppm, percentage make up water is 10% and TDS in feed water is 300 ppm, then the percentage blow down is given as:

$$\text{Blowdown (\%)} = \frac{300 * 10}{3000} = 1\%$$

If boiler evaporation rate is 10,000 lb/hr, then the required blowdown rate is

$$= \frac{10000 * 1}{100} = 100 \text{ lb/hr}$$

What parameters establish the cycles of concentration or blowdown regulation?

There are two tests used to establish the cycles of concentration or to regulate the frequency and volume of blowdown. These are chloride level and specific conductance.

Chloride Test

Chloride is chosen as the indicator for cycles of concentration because:

1) It is always present in the makeup water

2) It does not change character when heated

3) It do not react with the chemicals in the water treatment, and

4) It does not leave the water in the boiler when steam is produced

If the Chloride in the water doubles, all the solids would have doubled.

Example:

If the makeup chlorides are 20 ppm and the boiler water chlorides are 100 ppm, the boiler is at 5 cycles of concentration. If makeup chlorides are at 30 ppm and the boiler water is at 120 ppm, the boiler is at 4 cycles of concentration.

The Chloride Test is run on a sample of the raw water and on a sample of the water from the boiler sight glass. When the Chloride reading of the boiler water is 6 times the Chloride reading of the raw water, there are 6 cycles of concentration.

Specific Conductance Test

The second test used for regulating blowdown is specific conductance. A conductivity meter is used to measure the conductivity of the "make up" water as compared to the conductivity of the boiler water. The ratio of the two figures is the "cycles of concentration".

Example: If the makeup water conductivity is 300 umhos and boiler water conductivity is 2100 umhos, 2100 ÷ 300 equals 7 cycles of concentration.

Important: In general, the boiler should never be operated over 10 Cycles of Concentration

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Methods for controlling blowdown

Blowdown systems could be either manually or automatically controlled.

1) Manual control: The amount of blowdown is determined by performing tests to determine the amount of dissolved solids in the boiler water. The operator must be thoroughly instructed in the correct blowdown procedure. Mud or bottom blowdown is usually a manual procedure performed for a few seconds on intervals of several hours. It is

designed to remove suspended solids that settle out of the boiler water and form a heavy sludge.

2) Automatic blowdown: The automatic controllers sense the boiler TDS in terms of electrical conductivity and automatically open or close the surface blowdown lines to control exactly the right minimum level. The operator must check that the controls are set for required blowdown and that they function properly. Automatic controls can have a significant impact on efficiency, especially if steam loads vary widely. Surface or skimming blowdown is designed to remove the dissolved solids that concentrate near the liquid surface. Surface blowdown is often a continuous process.

Uncontrolled or continuous blowdown is wasteful. Automatic blowdown controls can sense and respond to boiler water conductivity much more effectively.

Energy Savings due to Reduction in Blowdown

Assuming the feedwater consists of 60% returned condensate and 40% makeup water; the analyzed sample tests alkalinity (as $CaCO_3$) of 70 ppm and the maximum allowed is 700 ppm. Therefore the concentration limit is 10.

If additional recovery results in a 67% condensate, feedwater quality is improved and a lower blowdown rate results. The total alkalinity (as CaCO3) is reduced to 70 to 58, allowing the concentration to increase from 10 to 12. Correspondingly the blowdown rate is proportionately reduced by 1.7% from 10 to 8.3 percent.

Actual blowdown and feedwater requirements for steam production of 100,000 lb/day are calculated by using several formulas:

$F = E / (1 - B)$

Where:

- F = Feedwater requirements, lb/day

- E = Steam generated, lb/day

- B = Blowdown, percent (expressed as decimal)

At 10 percent blowdown,

$F = 100,000 / (1 - 0.10)$

= 1,111,111 lb/day

At 8.3 percent blowdown,

F = 100,000/ (1-0.083)

 = 1,090,513 lb/day

The daily reduction resulting from the 1.7% blowdown decline is 20,598 lb, which is applied to determine fuel savings. (Heat content values are obtained from saturated steam tables).

S = R x H x C / (V x E)

Where

- S = Fuel savings, dollars/day
- R = Blowdown reduction, lb/day
- H = Blowdown heat content, Btu/lb
- C = Fuel cost, $ per unit
- V = Fuel heating value, Btu/lb
- E = Boiler efficiency, % expressed as decimal

Daily savings when burning No. 6 fuel oil with a heating value of 142,440 Btu/gal costing $1.1 per gallon in an 80% efficient boiler are:

S = 20,598 x 309 x 1.1 / (142440 x 0.80)

S = $61.44/day

Consequently, returning 7% more condensate of the boiler realizes a fuel savings of $21,504 per annum assuming 350 days operation.

Blowdown Heat Recovery

Although reducing blowdown results in substantial fuel savings, this function cannot be eliminated entirely. A boiler operating on high quality feedwater needs very little blowdown, while equipment using feedwater containing solids, alkalinity or silica requires a much higher rate, may be even continuous discharge.

A comprehensive energy conservation program, apart from ensuring correct amount of blowdown must include the use of flash tanks and heat exchangers to reclaim some of the energy wastage in boiler blowdown.

1. Flash Steam Recovery

Flash steam heat recovery is a method for recovering at least 85% of the blowdown heating value.

About half of the heat contained in the blowdown water is recovered in the form of flash steam by discharging the flow to a flash tank, usually operated at 5 psig. A portion of the blowdown flashes to steam at the lower pressure and is available for use in the deaerator or for other low pressure demands.

Flash steam recovery is calculated using the formula:

$A = (H - W) / L$

Where:

- A = Flash steam %

- H = Boiler blowdown water heat content, Btu/lb

- W = Water heat/content at flash pressure, Btu/lb

- L = Steam latent heat content at flash pressure, Btu/lb

Assuming, a flash tank is added to a boiler operating at 235 psig and generating 1,000,000 lb/day of steam, the blowdown rate is 5%, or 52,632 lb/day

$A = (376 - 196) / 960$

$A = 0.1875$ or 18.75%

Daily heat recovery is calculated by applying the formula

$G = A \times J \times K$

Where:

- A = Flash steam, %

- G = Daily heat recovery, Btu

- J = Blowdown, lb/day

- K = (L+W), which is heat content of saturated vapor at flash pressure, Btu/lb

Using the numbers

G = 0.1875 x 52,632 x 1156

= 11,407,986 Btu/day

2. Blowdown heat recovery

Heat exchangers can reclaim the sensible heat from the blowdown that goes into sewerage for heating boiler makeup water and the like.

In most cases, the heat exchanger is designed to reduce the temperature of the blowdown water to within 20 °F of the temperature of the makeup water.

Additional heat recovered is calculated from the following formula:

M = J x (1- A) x (W – P)

Where:

- M = Additional daily heat recovery, Btu

- P = Water heat content at exchanger outlet, Btu/lb

M = 52,356 x (1- 0.1875) x (196-48)

M = 6,296.531 Btu/day

Total heat recovery from the flash steam and the heat exchanger is 17,704,517 Btu/day;

Total heating value in the blowdown is 52,632 x 376 Btu/lb or 19,789,632 Btu/day. The two methods captured 89% of the blowdown water energy.

Summarizing:

Inadequate treatment of boiler water can waste as much as 15-18% of energy and can even result in plant damage. Feedwater, if not properly treated shall result in scale build-up which can reduce boiler efficiency by as much as 10 to 12 percent and can even result in plant damage. It is important to maximize condensate return; an additional 15 to 18% of boiler energy from the steam system is needed to re-heat each pound of cold makeup water.

PART-3   STEAM DISTRIBUTION MANAGEMENT

The primary purpose of an effective steam distribution system is to link the output of the steam generation system to the steam end use equipment. The distribution system should supply high-quality steam to the end use equipment at the required rate and pressure, and with the minimum heat loss.

Key components include steam distribution piping, valves, and flanges, distribution system insulation, steam traps, air vents, drip legs, and strainers.

Optimum Pipe Sizing

Steam piping transports steam from the boiler to the end-use services whereas condensate return piping transports condensate back to the boiler. Important characteristics of well-designed steam & condensate system piping are these that are adequately sized, configured, insulated and supported.

The steam flow through the pipe in terms of pressure and volume required is dictated by the process needs. Proper sizing of steam pipelines help in minimizing pressure drop. There are broad limits on the velocities of steam in pipes imposed by considerations of related erosion rates etc. On the basis of practical experience, acceptable velocities limits are:

- Superheated 50-70 m/sec

- Saturated 30-40 m/sec

- Wet or Exhaust 20-30 m/sec

Velocities exceeding these are likely to generate noise and erosion, specifically if there is wet steam. For shorter branch connections, it is advisable not to exceed 15 m/s. The starting conditions at the beginning of the steam main are usually provided by the boiler specifications. There are fraction allowances in a pipe, the friction factor 'F' depending on the Reynolds number and the relative roughness of the pipes internal surface, defined as the ratio of a mean roughness height 'k' to the pipe diameter. For commercial, non-corrosive steel tubes commonly used in steam and water service, k may be taken to be 0.05 mm. As the network in general will include tees, bends, valves etc, these will also contribute to overall friction.

Standard data tables are available that help in making the final selection. The equations, on which these data is based, make use of the following empirical relation:

$$(P_1^{1.9375} - P_2^{1.9375}) / L = 0.00012 \times Q^{1.853} / d^{4.987}$$

Where:

- P_1 = Initial pressure at the beginning of a run of pipe (psig)

- P_2 = Final pressure at the end of a run of pipe (psig)

- L = Equivalent length (ft) of the pipe after the resistance of fitting has been taken into account

- Q = Quantity of steam passing (lb/hr)

- d = Diameter of the pipe (inches)

The steam piping should be sized, based on both 'permissible velocity' and the available 'pressure drop' considerations in the line. Selecting a higher pipe size will reduce the pressure drop and thus the energy cost. However, higher pipe size will increase the initial installation cost. Hence, care should be taken in selecting the optimum pipe size.

If the condensate pipes are not sized properly, they may either impose unacceptably high back pressure on the traps when they are undersized or a heavy capital investment when they are unnecessarily oversized. In practice, the condensate piping have to handle two phase flow, i.e. water and flash steams, with ratio depending on the operating conditions. As a rule of thumb, it is best to size a condensate pipe as if it were carrying water under starting conditions only. It would then have adequate capacity to carry the condensate, as well as flash steam, under running conditions and to allow for the discharge of air at start-ups.

The following simple rules may serve as guidelines:

a) Ensure that the distributing pipework is of the right size. Oversized pipes increase capital, maintenance and insulation costs, and generate higher surface heat losses. Undersized pipes require higher pressure and extra pumping energy and have higher rates of leakage.

b) Redundant, obsolete pipework wastes energy as it is kept at the same temperature as the rest of the system; the heat loss per length of pipe remains the same. The heat losses from extra piping add to the space heat load of the facility and thus to the unnecessary ventilation and air-conditioning needs. Moreover, redundant pipework receives scant maintenance and attention, incurring further losses.

c) In a neglected steam distribution system, leaks are common in the piping, valves, process equipment, steam traps, flanges, or other connections. Fixing steam leaks is a simple and low cost opportunity to save energy and money.

d) Install meters and keep track of where the steam is going. The facility-wide and individual process-unit steam balances will help in accessing losses in a better way.

e) Important configuration issues are flexibility and drainage. With respect to flexibility, piping especially at equipment connections, needs to accommodate thermal reactions during system startups and shutdowns. With respect to drainage, the piping should be equipped with a sufficient number of appropriately sized drip legs for effective condensate drainage.

f) All pipes should have fall in the direction of the steam flow typically not less than 125 mm for every 30 meter length. The piping should be pitched properly to promote the drainage of condensate to these drip lines. Typically these drainage points experience two very different operating conditions: normal operation and startup. Both load conditions should be considered in the initial design.

g) Drain points should be provided at intervals of 30 to 45 meters along the main. Drain points should also be provided at low points in the mains and where the steam main rises. Ideal locations are the bottom of expansion joints and before reduction and stop valves.

h) Drain points in the main lines should be through an equal tee connection only. It is preferable to choose open bucket or TD traps on the account of their resilience.

i) The branch lines from the mains should always be connected at the top. Otherwise, the branch line itself will act as a drain for the condensate.

j) Expansion loops are required to accommodate the expansion of steam lines while starting from cold.

k) To ensure dry steam in the process equipment and in branch lines, steam separators can be installed as required.

Proper Insulation of Steam Pipe

The steam distribution network including pipes, fittings, flanges, valves, traps and the hot process equipment must be insulated to avoid excessive loss of heat to the atmosphere. The

insulation also benefits in a way that the steam reaches the point of use at the desired temperature and pressure.

Important insulation properties include thermal conductivity, strength, abrasion resistance, workability, and resistance to water absorption.

Thermal conductivity is the measure of heat transfer per unit thickness. Thermal conductivity of insulation varies with temperature; consequently, it is important to know the right temperature range when selecting insulation. In general, the lower the thermal conductivity, the higher will the resistance to heat transfer be.

Some common insulating materials used in steam piping include calcium silicate, mineral fiber, fiberglass, perlite, and cellular glass. The American Society for Testing and Materials (ASTM) provides standards for the required properties of these and other insulation materials.

Insulation blankets (fiberglass and fabric) are commonly used on steam distribution components (valves, expansion joints, flanges etc.) to enable easy removal and replacement for maintenance tasks.

The following simple rules may serve as guidelines on insulation:

a) The smaller the pipe diameter, the thinner the insulation.

b) Good quality insulation with low thermal conductivity is far better than a poor quality material.

c) The higher is the temperature of the surface to be insulated; the better is the return on investment.

d) It is the initial 1 ½" thickness of insulation which is critical to heat loss. It is more important that all steam pipework be insulated to some degree, rather than having some pipework well insulated while other sections are left bare. Therefore it is always advantageous to cover up all fittings, valves, supports and flanges.

e) Running pipes in groups greatly reduce heat losses. All future installations should incorporate this principle.

f) Drafts and air movements greatly increase heat losses especially when pipe are not well insulated.

The optimized insulation is the most economic one.

Example: If only 10 flanges are not insulated on a 4-in. diameter pipe carrying steam at 125 psig, the annual heat loss is equivalent to 2,450 m^3 of natural gas worth $370.

Example: A 3-m (10-ft.) length of uninsulated 4-in steam pipe wastes more than twice as much money in steam costs per year than the cost of insulating it with mineral fiber and aluminum jacket.

Plugging Leaks

The first concern for efficient energy utilization is that there is no heat loss through direct steam leakage from the faulty joints, valves and steam traps. Steam leaks commonly develop around valve stems, pressure regulators, and pipe joints. This kind of waste is easy to detect and shall not be allowed.

Even a small leak represents a significant loss of energy during the year. For example, if steam at a pressure of 100 psi is leaking from an 0.8 mm diameter hole, the steam lost will cause up to 1,500 liters of oil to be wastefully burned a year. The table below provides a glimpse of energy loss from leaking steam.

Cost of Various Sized Steam Leaks at 100 psi (Assuming steam costs $5.00/1,000 lbs)			
Size of Orifice (in)	Lbs Steam Wasted Per Month	Total Cost Per Month	Total Cost Per Year
1/2	835,000	$4,175.00	$50,100.00
7/16	637,000	3,185.00	38,220.00
3/8	470,000	2,350.00	28,200.00
5/16	325,000	1,625.00	19,500.00
1/4	210,000	1,050.00	12,600.00
3/16	117,000	585.00	7,020.00
1/8	52,500	262.50	3,150.00

Generally, leak repairs have a short payback (two months or less) and preserve the life of surrounding insulation.

Steam Trap and Associated Pipelines

A steam trap is a kind of automatic valve which distinguishes condensate from steam and affects condensate removal. Three types of steam traps are commonly used:

1) In the first type, this distinction is made on the basis of their density difference. These are also known as mechanical traps and include float traps and bucket traps.

2) In the second type, they react to the difference of their temperature. These are also called thermostatic traps and include balanced-pressure traps, bimetal traps and liquid expansion traps.

3) The third type operates on the difference in their flow characteristics. These are also called the thermodynamic traps.

Steam traps play a very important role in steam distribution systems.

The identification of a correct steam trap is made on the basis of the proposed application area and the working conditions (working pressure and the temperature). An exact analysis of these conditions will give the proper data necessary for selecting the type and size of the steam trap. After a careful selection, it must be properly installed, tested, periodically inspected, cleaned and maintained.

The following facts must be noted:

1) Traps need cleaning periodically. A recommended practice is to drop a short length of pipe vertically below the supply to the trap (called a dirt leg) which can be cleaned easily and frequently.

2) Traps can be seriously damaged by scale and dirt. A good practice is to install strainers ahead of the traps which should be inspected and cleaned frequently.

3) Traps are subject to severe wear if steam blows through continuously. They should be inspected for worn valve parts or a change in operating conditions.

4) When a steam trap fails to discharge, the heating system should be inspected to ensure that all units are drained with separate traps, thus guarding against short circuiting, loss of energy, and reduction of operating efficiency.

5) Discharge lines should be short and self draining traps should be fitted with dirt pockets, test valves, and drains.

6) Steam traps handling large volumes of air require more frequent inspection and proper venting for efficient operation. Vents should be used to avoid air binding and ensure positive drainage.

In steam systems, steam traps can fail (on average) up to 25 percent of the time. Steam leaking from pipe fittings, valves and traps can cause large energy losses.

Example: Failure of a single nominal 1/8-in trap in a 100-psig steam system can lose the equivalent of 11,600 m^3/y of natural gas, approximately worth $1,700.

Steam Use in Heating

The primary objective of the effective steam utilization is to maximize the transfer of heat of the steam to the end use equipment. The following need to be noted:

1. *Providing dry steam for process:* The best steam for industrial process heating is dry saturated steam; neither wet nor superheated. If steam is wet, the trapped moisture particles reduce the total heat in the steam (since they carry no latent heat), and increase the resistant film of water on the heat transfer surfaces, thereby slowing down the rate of heat transfer. Superheated steam is not so practical because it gives up its heat slower than the condensation heat transfer of saturated steam.

   Boiler without a super-heater cannot deliver perfectly dry saturated steam. At best, it can deliver only 95% dry steam. The dryness fraction of steam depends on various factors, such as level of water in the boiler drum, the effect of peak loads, the surging within the boiler, the pressure on the water surface in the boiler and the solids content in the boiler water. Any one of these factors can cause droplets of water to be a part of the steam. A steam separator may be installed on the stem main as well as on the branch lines to reduce the wetness in steam and improve the quality of steam going to the user units.

2. *Using Steam at Lowest Pressures:* Reducing the boiler's steam operating pressure to the minimum needed by the end user, or reducing the temperature of the fluid (not overheating the fluid), can dramatically affect the energy savings. These savings come from burning less fuel in the boiler or heater and lowering the amount of heat lost in the piping system.

   To change the system's operating pressure or fluid temperature, verify that the boiler and end devices can run at the lower pressure (temperature). The potential environmental and dollar savings are worth investigating. Key end use equipment includes, heat exchangers, unit heaters, vessels, tanks and other process-specific steam use equipment.

   In one of the liquor factory, the tanks were found to be operating at a temperature of 180°F when it was known that a temperature of 150°F was adequate for the particular process.

The unnecessary overheating was causing a wasteful use of about 13,700 gallons of fuel oil a year. A simple temperature control device with temperature sensor and 'On-Off' control valve on the steam can prevent this energy loss.

Caution: The energy manager should consider pressure reduction carefully before implementing it. Adverse effects, such as an increase in water carryover from the boiler owing to pressure reduction, may negate any potential saving. Pressure should be reduced in stages and no more than a 20 percent reduction should be considered.

3. *Heating by Direct Injection:* In plants where water or process liquor is heated by direct steam injection, one can see the liquid in the tank boiling away, thereby creating clouds of vapor. This is waste of steam; besides it creates unpleasant working conditions. Ideally, the injected steam should be condensed completely as the bubbles rise through the liquid. This is possible only if the inlet pressure is kept low around 7 psig and certainly not over 14 psig. Recommended arrangement includes a sparge pipe with large number of small diameter holes (2 to 5 mm) facing downwards should be placed in the tank.

4. *Proper Air Venting:* A 0.25 mm thick air film offers the same resistance to heat transfer as a 330 mm thick copper wall. Air in a steam system will also affect the system temperature. The presence of air inside the process equipment will reduce the partial pressure of steam in the steam-air mixture, thus dropping the overall temperature of the steam-air mixture, which is the heating media. It is however, impossible to avoid the entry of air into a steam system that is working intermittently. If the steam condenses during the shut downs, air tends to be sucked in due to the partial vacuum created. Air is also pushed into the process equipment from the steam mains at the time of start up. The situation can be improved by installing properly sized air vents at appropriate positions in the pipelines, and equipment at the highest points. Automatic air vents for steam systems (which operate on the same principle as thermostatic steam traps) should be fitted above the condensate level so that only air or steam-air mixtures can reach them.

Summarizing:

Taking care of the steam distribution system provides one of the best opportunities for savings. The cost of maintaining steam traps and checking piping flanges and valves for leaks requires little or no capital investment.

1) Ensure that distribution system piping is correctly sized to produce the appropriate system pressure drops.

2) Ensure that the distribution pipes are properly laid out, adequately drained and adequately air vented.

3) Ensure that the distribution system piping is adequately supported, guided, and anchored, and that appropriate allowances are made for pipe expansion at operating temperatures.

4) Select, size, and maintain steam traps for specific end use applications. Blowdown of non-condensable from condensing equipment is critical. If non-condensable are not removed from condensing applications, the condensing equipment will quickly cease to function. The rule of thumb is that for every 1% of non-condensable in steam, the heat transfer coefficient decreases by 10%.

5) A 100-foot length, uncovered 6" diameter pipe carrying steam at 100 psi can waste 3,000 liters of oil a year. Every square feet of unlagged steam heated surface operating at a steam pressure of 100 psi is equivalent to an hourly loss of 1 lb of steam per hour.

6) Make arrangements to collect condensate and pump it back to the feedwater circuit.

7) Insulate all distribution system pipes, flanges, and valves.

8) Major housekeeping items that deserve attention are steam leaks, pipe insulation, and steam traps. Giving maintenance staff proper training and the time to thoroughly go through the steam distribution system is generally well worth the expenditure.

9) Use dry steam for heating at appropriate pressures. Don't overheat and provide air vents to eliminate air film.

A good starting point to an energy efficiency program is to conduct an energy audit. This starts with identification of the components of the system boundary and encompassing the two most important objectives:

- Define the status of the system in terms of overall efficiency

- Identify areas where energy (dollars) can be saved

Certain data must be gathered and calculations completed in order to determine the status of the system in terms of efficiency and sources of energy loss.

This section presents some ideas that may be applied to the boiler efficiency program.

Combustion and Waste Heat Recovery

1) Check and verify the boiler efficiency regularly. Monitor and compare the boiler performance related data to standard targets regularly.

2) Monitor the flue gas combustibles and the combustion excess air regularly. Adjust as conditions change. Operating your boiler with an optimum amount of excess air will minimize heat loss up the stack and improve combustion efficiency.

3) The optimum amount of excess air required for the combustion reaction depends on fuel composition and the type of boiler used. Heavier fuels require higher excess air and the stoker fired boilers need more air than oil fired boilers.

4) Check for and eliminate the entrance of unwanted air into the boiler and flue gas exhaust system.

5) Keep burners adjusted to optimum efficiency. Establish a burner maintenance schedule. Inspect and replace fault burners.

6) Replace obsolete boilers with high-efficiency, low-emissions units fitted with new burner technology and heat recovery options suited to the required demand. Excess air needs of oil fired boilers depend on the design of the burners and atomizers, and on the cleanliness of the burner nozzles. Low excess air burners, which can operate efficiently at much lower levels of excess air, are available for liquid and gaseous fuels.

7) Consider using fuel direct injection (FDI) technology. A FDI regenerative burner reduces NOx emissions by about 90 percent compared with ordinary regenerative burners.

8) Convert fuel from oil to natural gas, where gas supplies are available. (Although this may save more money than energy, it has some operational and environmental advantages.)

9) Check all the control settings regularly. Fit controls with locks to prevent tampering and unauthorized adjustment.

10) Maintain the best operating condition of air and fuel controls.

11) Inspect the fireside and waterside heat transfer surfaces when the boiler plant is shut down; keep the surfaces clean. Ensure that the fireside anti-fouling equipment works properly.

12) Use continuous oxygen monitors and operator adjustments to minimize excess air level. Use continuous oxygen trim to automatically minimize excess air level.

13) Draw warmer combustion air from ceiling of boiler plant, where the incoming air has the highest possible temperature year-round.

14) Install an integrated computerized management system for generating and distributing thermal energy.

15) Consider alternate uses for the remaining heat in the flue gas. Use it for space heating, process or drying the product or biomass fuel.

16) Install equipment to recuperate heat on the flue gas system. This includes economizers, combustion air preheaters and flue gas condensers (indirect or direct contact). If already in place, review its efficiency and consider replacing or upgrading it.

17) Keep unwanted air out: Effective control of excess combustion air also involves guarding against infiltration (ingress) of unwanted air into the boiler combustion cavity or the flue system. The air enters through cover leaks, observation ports, faulty gaskets and other openings.

18) O_2 monitoring may be drastically distorted by air infiltration into the furnace and the convection passages downstream of the burners. CO concentration is unaffected by air infiltration, and thus gives a more certain indication of combustion.

19) Avoid subjective judgments; many operators are in a habit of taking judgments based on the appearance of flame or color of flue gas. This usually results in pumping lots of excess air or Btus (dollars) blowing out of the stack. Remember, the deficient air constitutes a safety hazard and excessive stack emissions.

Makeup Management

1) Maintain records of the amount of makeup water used. This helps in analyzing the presence of leaks or losses in the system. They also assist in developing a more effective chemical treatment program.

2) Excessive water use indicates a change in system operation and, therefore, a change in efficiency.

3) Maximize efficiency and capacity of existing pretreatment system

4) Use of alternative raw water sources of better chemical and heat content quality

5) Consider improved pretreatment systems to minimize boiler blowdown losses

6) Use of process heat exchangers to preheat makeup water

7) Adapt a chemical treatment system in addition to the fixed water treatment

Feedwater, Condensate and Blowdown Management

1) Return a greater percentage of condensate to boiler

2) Use condensate monitors to check the contaminants and quality of return water

3) Use of economizers to preheat boiler feedwater

4) Maintain good steam quality with a program of regular water chemical treatment and the blowdown regime.

5) Evaluate deaerating system to ensure maximum operating efficiency.

6) Consider use of boiler blowdown heat recovery to preheat makeup water.

7) Use flash tanks to generate low-pressure steam from the blowdown (and use it in other heating applications, such as the de-aerator).

Steam and Condensate Management

1) Look for opportunities to rationalize and streamline the steam and condensate network.

2) Return more condensate to boiler system. Consider installing a system for closed-loop pressurized condensate return.

3) Locate the areas of steam/condensate leakages and correct the problem.

4) Repair insulation on steam and condensate lines. Add insulation where it is inadequate. Evaluate the economics of upgrading or adding more insulation on current energy cost trends.

5) Review whether the steam and steam condensate recovery network (and heating coils and other steam-using equipment) has proper drainage. This will eliminate water hammer, losses and damage.

6) Shut down the steam and condensate branch system when it is not needed. Plug all obsolete, unused and redundant piping.

7) Set up a steam trap inspection and maintenance program and procedures. Repair and/or replace faulty steam traps.

Steam Generation Management

1) Add measuring, metering and monitoring equipment to the boiler and heat distribution systems for fuel, steam, heating fluid, condensate and blowdown flows.

2) Try to stabilize heating demand. To do this, review the schedule for process demand. This will minimize boiler load swings and maximize boiler efficiencies. Try to operate boilers at full load.

3) Operate steam generator at proper cycles of concentration to control blowdown losses

4) Minimize blowdown losses by operating at maximum cycles of concentration with automatic blowdown control

5) Repair faulty insulation on boilers

6) Balance load factor on alternate boilers with respect to overall boiler efficiency ratings

7) Replace worn out burners

8) Replace outdated, inefficient boiler with new systems

9) Repair lost steam generating tubes, baffles and refractory to improve overall efficiency

10) Operate the boiler (heater) at the lowest steam pressure (or heating fluid temperature) that meets the needs of the production process

11) Convert from indirect to direct steam heating, where appropriate. Convert from steam to heating fluid heating, where appropriate.

SAMPLE QUESTIONAIRE

The following questions will help uncover boiler inefficiencies.

Management

1) Is the use of steam and heating fluid throughout the facility budgeted? Is it monitored? Are there consumption targets?

2) If so, are the users of thermal energy accountable for its use? How?

3) Are there approved procedures and work instructions governing thermal energy generation, distribution, monitoring and other processes?

4) Have employees learned about the significance of energy and utility conservation, and do they use correct practices?

5) Are boiler and heater operators involved with the efforts to conserve energy and utilities?

6) Are employees aware of how much energy and utilities cost, and how much is being spent for these in the facility? Are they significantly interested in improving the results?

7) Is there a system for communicating to employees the results of efforts to conserve energy and utilities?

Heat consumption

1) Are there procedures for shutting off thermal energy-using production equipment and auxiliary production equipment when not in use?

2) Are the above procedures implemented?

3) Is steam or heating fluid produced at temperatures or pressures greater than those required by end-user processes, product, plant or equipment?

4) In multiple boiler installations, how is steam demand matched to boiler deployment? How is it done on weekends, during non-production periods and in various seasons?

Fuels

1) Can a cheaper alternative source for thermal energy be used?

2) Can process by-products be used as an auxiliary fuel or fuel supplement?

3) If natural gas is used, have the costs of uninterruptible versus interruptible supply been evaluated?

4) Is the boiler fitted with dual capability to use natural gas or fuel oil to take advantage of interruptible gas supply contracts?

Fuel storage

1) Are heated oil tanks and associated piping adequately insulated?

2) Is the external insulation for the above items watertight?

3) Is oil heated at the correct temperature?

4) Is solid fuel (e.g. biomass) protected against rain? Is it dried?

Boilers and steam distribution

1) Is the flue gas free of combustibles?

2) Is the boiler efficiency checked on a regular basis?

3) Is a proper method for determining boiler efficiency being used?

4) Is the efficiency acceptable for the type of boiler and fuel?

5) Is the burner operating in the "zone of maximum combustion efficiency"?

6) Are the heat losses of the boiler and system known and quantified?

7) Is the flue gas checked for combustibles, carbon monoxide and oxygen content on a regular basis?

8) Is the content within an acceptable range?

9) How is the excess combustion air managed? How frequently?

10) Can unwanted air get into the boiler and the flue stack? What type of air or fuel control is used? How is it maintained?

11) What type of equipment is used for controlling and monitoring the system? What instruments are used?

12) Where is the combustion air intake located?

13) Is the combustion air preheated? If so, how?

14) Are the NOx levels in the flue gas known and monitored? Are they within an acceptable range?

15) What are the flue gas temperatures at various boiler loads? Are they monitored?

16) Is heat being recovered from flue gas? What type? How efficiently?

17) Is there any evidence of soot buildup on the fireside surface of the boiler?

18) Is there a program for inspecting and removing soot and scale from heat transfer surfaces of the heater and boiler? From process equipment?

19) Is the flame in the combustion chamber bright and clear? Does it fill the combustion chamber without encroaching?

20) What is the blowdown rate, and is it at the level recommended by water treatment specialists? Is it based on the content of dissolved solids (DS) in the boiler water? Have the levels of DS content been calibrated to conductivity?

21) How is the blowdown rate controlled?

22) Is there a system for recovering heat from the blowdown?

23) Is there redundant, oversized or undersized steam piping that causes heat losses? Is there an inspection program for it?

24) Are steam lines, flanges, valves and condensate lines adequately insulated? Is the insulation dry and protected against water ingress?

25) Is steam or condensate leaking?

26) Is the makeup water preheated? If so, how?

27) Is the condensate return rate adequate? Has it been verified?

28) Is the correct type of steam traps for the application being used?

29) Is there an adequate maintenance program for inspecting, repairing and replacing steam traps?

30) How many of the traps are faulty?

Summary

The performance parameters of boiler, like efficiency and evaporation ratio reduces with time due to poor combustion, heat transfer surface fouling and poor operation and maintenance. Even for a new boiler, reasons such as deteriorating fuel quality, water quality etc. can result in poor boiler performance. Boiler efficiency tests help us to find out the deviation of boiler efficiency from the best efficiency and target problem area for corrective action.

Flue gas temperature, oxygen and carbon dioxide measurements are good indicators of the excess air level and boiler efficiency changes. The larger the excess air and the flue gas temperature, the larger shall be the losses. An often stated rule of thumb is that boiler efficiency can be increased by 1% for each 15% reduction in excess air or 40°F reduction in stack gas temperature.

The boiler water must be sufficiently free of deposit forming solids to allow rapid and efficient heat transfer and it must not be corrosive to the boiler metal. Deposits in boilers may result from hardness contamination of makeup water and corrosion products from the condensate and feed water system.

The heat recovery from flue gases and boiler blowdown provides another means of tapping energy. The payback period varies from 6 months to 2 years depending on the scale of operation.

Last but not the least, boiler operating parameters is the key to energy savings and unless you measure it, you don't get it.