Improving Boilers and Heater Energy Efficiency

4

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This guidebook, provided by Natural Resources Canada's (NRCan's) Office of Energy Efficiency (OEE), is for owners and operators of boilers and heaters who want to save energy, improve their bottom line and reduce greenhouse gas emissions that contribute to climate change. As these readers already know the basics of combustion processes and relevant plant operations, these concepts, as well as the environmental effects of combustion, particularly nitrogen oxide (NO_x) emissions, are mentioned only briefly. Detailed information can be found elsewhere.

The guidebook focuses on giving practical tips on improving the energy effectiveness of boiler and heater operations. It aims to stimulate thinking about the ways to achieve greater energy efficiency and to lessen the environmental consequences of energy use, in keeping with the Government of Canada's policy on climate change.

UNITS OF MEASUREMENT

Although Canada officially uses the International System of Units (SI) or metric system, its largest trading partner, the U.S., does not. Consequently, a large proportion of industrial equipment – steel pipe being a common example – is made to Imperial units. Furthermore, many American codes and standards written in Imperial units, such as the one for determining boiler efficiency, have been adopted as the industrial norm for Canada. Since most steam plants employ equipment in Imperial and metric units, this document provides both, with the metric unit presented first.

ACKNOWLEDGEMENT AND DISCLAIMER

This guidebook is based on *An Energy Efficiency and Environment Primer for Boilers and Heaters* (Primer), jointly published in 2000 by the Environmental Partnerships Branch of the Ontario Ministry of the Environment, Union Gas Limited, Enbridge Gas Distribution (formerly Enbridge Consumers Gas), and the OEE of NRCan. The OEE provided funding under the auspices of the Canadian Industry Program for Energy Conservation (CIPEC). The OEE also funded this condensed version of the Primer, which provides more detailed information, especially on combustion emissions.

The views and ideas expressed in this guidebook are those of the authors and do not necessarily reflect the views and policies of the funding organizations. The generic opportunities present herein do not represent recommendations for implementing them at a specific site. Before modifying any equipment or operating procedures, consult qualified professionals and conduct a detailed site evaluation.

SOURCES OF OTHER INFORMATION

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The Canada Centre for Mineral and Energy Technology (CANMET) produces excellent technical industrial publications, most of them related to energy efficiency. They include industry-specific monographs, project reports, fact sheets and the Federal Industrial Boiler Program. To obtain a listing of current publications, contact

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Relevant manuals in NRCan's Energy Management Series include

- *Process Insulation* (Cat. No. M91-6/001E)
- *Boiler Plant Systems* (Cat. No. M91-6/006E)
- *Process Furnaces, Dryers and Kilns* (Cat. No. M91-6/007E)
- *Steam and Condensate Systems* (Cat. No. M91-6/008E)
- *Waste Heat Recovery* (Cat. No. M91-6/020E)

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COMBUSTION PROCESSES have been, are and will be for the near future, the prime generator of energy in our civilization, which is burning fossil fuels at an ever-increasing rate. The processes must be managed well for the sake of the environment and the sustainability of civilization.

The principles of combustion are common to heaters, boilers and other forms of industrial com- bustion, e.g. in furnaces and kilns. In this sense, **the term "boiler" is interchangeable with "heater"throughout this text** (unless stated otherwise).

Conventional fuels consist mainly of two elements – carbon and hydrogen. During combustion, they combine with oxygen to produce heat. The fuel value lies in the carbon and hydrogen content. Non-fossil fuels, such as biomass and alcohol, also contain oxygen in their molecular structures.

Ideally, combustion breaks down the molecular structure of the fuel; the carbon oxidizes to carbon dioxide (CO_2) and the hydrogen to water vapour (H_2O). But an incomplete process creates undesir- able and dangerous products. To ensure complete combustion, even modern equipment with many features must operate with excess air. That is, more air (carrying about 21 percent oxygen by volume) is passed through the burner than is chemically required for complete combustion. This excess air speeds up the mixing of fuel and air.

On one hand, this process ensures that nearly all the fuel receives the oxygen it needs for combustion before it is chilled below combustion temperatures by contact with heat exchange surfaces. It also prevents fuel that is not burned completely from exploding within the boiler.

On the other hand, excess air wastes energy by carrying heat up the stack. A fine line exists between combustion efficiency and safety in ensuring that as little excess air as possible is supplied to the burner.

Boiler owners and operators will want to know if their operations are efficient. As the objective is to increase the energy efficiency of boilers, reviewing the causes of heat loss in boiler operations may be useful.

HEAT LOSSES in a boiler are well described by the American Society of Mechanical Engineers (ASME) in its rigorous PTC4.1 power test code (1973). The test code applies to any type of fuel used. However, natural gas or fuel oil fire most boilers and heaters in Canada. In such systems, many of the losses listed in the code do not apply. And other systems are small enough for their losses to be rolled into an "unaccounted for" category, for which a value can be assumed. A simplified method for quantifying boiler efficiency uses this equation:

Efficiency (E) % 5 (Output 4 Input) 3 100,
where: Output 5 Input 2 Losses

Alternatively,

Efficiency (E) % 5 100 2 losses, where losses can be calculated according to the ASME power test code.

Since this code uses Imperial units, it is necessary to convert temperatures to degrees Fahrenheit (°F) andheating units to British thermal units per pound (Btu/lb.), which can be done with the following conversion formulas:

°F 5 (1.8 3 °C) 1 32
Btu/lb. 5 0.4299 3 kJ/kg

The following four significant types of energy losses apply to natural gas and heating oil systems.

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 sulphur 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 5 [24 3 DG 3 (FGT 2 CAT)] 4 HHV, where

DG (lb./lb. fuel) 5 (11CO_2 1 8O_2 1 7N_2) 3 (C 1 0.375S) 4 3CO_2
FGT 5 flue gas temperature, ˚F
CAT 5 combustion air temperature, ˚F
HHV 5 higher heating value of fuel, Btu/lb.
CO_2 and O_2 5 percent by volume in the flue gasN_2 5 100 2 CO_2 2 O_2
C and S 5 weight fraction in fuel analysis

Minimizing excess air reduces dry flue gas losses.

Loss due to moisture from the combustion of hydrogen (LH)

The hydrogen component of fuel leaves the boiler as water vapour, taking with it the enthalpy – or heat content – corresponding to its conditions of temperature and pressure. The vapour is a steam at ve ry 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. This loss (LH) can be calculated as follows:

LH (%) 5 [900 3 H_2 3 (hg 2 hf)] 4 HHV, where

H_2 5 hydrogen weight fraction in fuel analysishg 5 1055 1 (0.467 3 FGT), Btu/lb.
hf 5 CAT 2 32, Btu/lb.

Where hg is the enthalpy of water vapour at 1 psig (pounds per square inch gauge) and the flue gas temperature (FGT), and hf is the enthalpy of water at the combustion air temperature (CAT) .

Only a condensing heat exchanger will reduce this loss appreciably.

Loss due to radiation and convection (LR)

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).

Losses that are unaccounted for (LUA)

For reasons mentioned earlier, use an assumed loss value of 0.1 percent for natural-gas-fired boiler systems and 0.2 percent for oil-fired systems.

Then, calculate efficiency as follows:

Efficiency (E) % 5 100 2 LDG 2 LH 2 LR 2 LUA, where

LDG5 Dry flue gas loss
LH 5 Moisture from hydrogen loss
LR 5 Radiation and convection loss
LUA 5 Unaccounted for losses

Begin a boiler plant program of energy management by assessing current boiler efficiencies. Then monitor boiler performance regularly to gauge the effect of established energy-saving measures and to set improvement targets.

The simplest way to calculate fuel-to-steam efficiency is the direct method of calculation **(see Table 1)**, using steam generation and fuel consumption data from operating logs. However, this method may not be as accurate as the indirect method due to errors in metering fuel flow and steam flow.

Table 1. Direct Method for Calculating Boiler Efficiency

1. Measure steam flow via kg (or lb.) over a set period, e.g. one hour. 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 flow of fuel over the same period. Use the gas or oil integrator, or determine the mass of solid fuel used.
3. Convert steam flow, feedwater flow and fuel flow to identical energy units, e.g. Btu/lb. or kJ/kg.
4. Calculate the efficiency using the following equation:
   Efficiency 5 100 3 (steam energy 2 feedwater energy) 4 fuel energy

Previously, this guidebook explained why it is necessary to operate a boiler with more air than is theoretically needed to burn all the fuel. Burner controls are therefore always set to provide some amount of excess air in all operating scenarios, typically from two to five percent O_2 in the flue gas. This guidebook has also pointed out that excess air incurs a heat loss; it enters the combustion system at ambient temperature and leaves at stack temperature. Therefore, reducing the oxygen level in the flue gas will reduce the heat loss.

A general rule is that a 1 percent reduction in excess oxygen will reduce fuel usage by 1 percent.

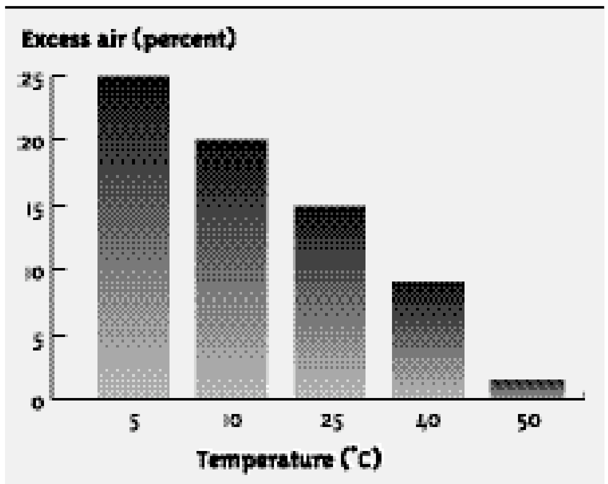
Controlling excess air is the most important tool for managing the energy efficiency and atmospheric emissions of a boiler system.

It is important to keep in mind that the air-to-fuel ratio is based on mass, not volume. The mass of air supplied to the mass of fuel being used (e.g. on a kilogram-to-kilogram basis) must be controlled. 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). As **Figure 1** shows, the effect of air temperature on excess air in the flue gas can be dramatic.

Similarly, the mass of natural gas flowing through a pipe will fall if the pressure in the supply pipe drops. (This may happen when the fuel flow to a second boiler increases.) Constant flow of liquid fuels, although less influenced by temperature, still depends on steady supply pressure to a valve maintaining a constant position. If pressure increases (e.g. when a second pump is started), the oil flow for a given valve position will also increase.

Variations in pressure and temperature can be corrected by sophisticated air and fuel control systems. Such systems can be expensive, so simpler systems are often used to avoid the expense. They are less precise and are set up with larger margins of excess air to avoid insufficient air conditions. They cannot ensure optimum continuous operation. Due to the higher heat losses (i.e. lower energy efficiencies) associated with the cruder control systems, it pays to evaluate the economics of investing in a high-quality control system.

Figure 1. Effects of Air Temperature on Excess Air Level



For existing combustion equipment, measuring and minimizing excess air is the primary way to optimize boiler and heater efficiency. Optimizing excess air (also referred to as O_2 control) means adjusting burner airflow to match fuel flow. Burner settings, initially calibrated during burner commissioning, should be reviewed regularly. Carbon monoxide (CO) is a sensitive indicator of incomplete combustion; its levels should range from zero to, perhaps, 50 parts per million (ppm) by volume, rather than the usual environmental limit of 400 ppm. Each boiler house should have accurately calibrated analysers for measuring O_2, CO and nitrogen oxides (NO_x).

For ideas about upgrades, a brief description of the types of air and fuel controls follows, in order of sophistication and costs.

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.

Mechanical jackshaft controls

The simplest type of modulating burner control is used in small burners, where the cost of more complex systems cannot be justified. These controls cannot measure airflow or fuel flow; 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.

Parallel controls

Separate drives in parallel controls adjust fuel flow and airflow, taking their signal from a master controller. The operator can adjust the flows individually and override the automatic control settings. These controls are usually applied to older, medium-sized boilers equipped with pneumatic controls. 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.

Cross-limiting control

Usually applied to larger boilers, cross-limiting control can sense and compensate for some of the factors that affect optimum air-to-fuel ratio. This control measures the flow of air and fuel and adjusts airflow to maintain the optimum value determined during calibration tests. Flue gas composition can be monitored and used in air control. Operations are safer when airflow cannot drop below the minimum needed for the existing fuel. They are also safer when fuel flow cannot be increased more than the existing airflow can burn. Oxygen trim is possible but, again, it has a limited range of adjustment. It must also respond slowly enough to allow the primary controls to reach equilibrium.

Automatic control of excess air (oxygen trim)

The high cost of purchasing and installing an oxygen analyser limits the use of oxygen trim controls to large boilers that use between $100,000 and $1 million worth of fuel annually. It increases energy efficiency by one to two percent. For very large boilers, where efficiency gains of 0.1 percent mean significant annual savings, these controls usually measure CO as well.

The negative effects of combustion on the environment – particularly greenhouse gas (GHG) emissions released to the atmosphere that contribute to global warming – have received much attention in recent years. This issue is addressed in the Kyoto Protocol (1997). Canada, which signed the Protocol, aims to reduce emissions between 2008 and 2012 by six percent of 1990 levels. Climate change resulting f rom global warming is one of the greatest challenges facing not only Canada but also the world. Managing combustion processes better and improving the efficiency of energy generation and use are two of the key strategies for reducing atmospheric emissions.

Therefore, this guidebook is being published in concert with Canada's policy on climate change as one of the tools for implementing it.

Canada's goal of reducing GHG and acid-rain emissions can be met only with the co-operation of the owners and operators of combustion equipment. It is beyond the scope of this guidebook to describe the emissions in detail. Instead, a brief overview is presented (see **Table 2** for a list of some emissions from combustion systems and their effects). More complete information can be obtained from *An Energy Efficiency and Environment Primer for Boilers and Heaters*.

Table 2. Emissions from Combustion Systems and Their Effects

EMISSION	SOURCE	EFFECT	GHG POTENTIAL RELATIVE TO CO_2
CO_2 (carbon dioxide)	Complete combustion of carbon in fuel	Global warming	1
CO (carbon monoxide)	Incomplete combustion of carbon in fuel	Smog	
SO_2 (sulphur dioxide)	Combustion of sulphur in fuel	Smog, acid rain	
NO_X (nitrogen oxides)	By-product of most combustion processes	Acid rain	
N_2O (nitrous oxide)	By-product of some combustion processes	Global warming	310
VOCs (volatile organic compounds)	Leakage and evaporation of liquid fuels (from, e.g., vehicles, fuel tanks, fuel pumps, refineries, solvents from paints)	Smog	
CH_4 (methane)	Principal component of natural gas; leakage from gas wells, pipelines and distribution systems	Global warming	21
H_2O (water vapour)	Combustion of hydrogen in fuel	Localized fog	
Particulates (dust, soot, fumes)	Unburned or partially burned carbon and hydrocarbons; also ash and dirt in fuel	Smog	
Trace elements	Impurities in fuel	Potential carcinogens	
Halogenated compounds	Compounds in fuel or combustion air containing halogens (chlorine, fluorine, bromine and iodine)	Potential carcinogens, global warming	Up to 24 000

Table 3. CCME* NO_x Emission Guidelines for New Boilers and Heaters

INPUT CAPACITY	NO_X EMISSION LIMIT, g/GJ** AND PPM (AT 3% O_2)***	
	10.5 TO 105 GJ/h (10 TO 100 MILLION Btu/h)	GREATER THAN 105 GJ/h (>100 MILLION Btu/h)
Natural gas	26 (49.6)	40 (76.3)
Distillate oil	40 (72.3)	50 (90.4)
Residual oil with less than 0.35% nitrogen	90 (162.7)	90 (162.7)
Residual oil with 0.35% or more nitrogen	110 (198.9)	125 (226.0)

* Canadian Council of Ministers of the Environment
** g/GJ 5 grams of NO_x emitted per gigajoule of fuel input
*** ppm 5 parts per million by volume, corrected to 3% O_2 in the flue gas (10 000 ppm 5 1%)

To correct ppm NO_x to 3% O_2: NO_x at 3% O_2 5 [NO_x measured x 17.9] 4 [20.9 2 O_2], where O_2 is oxygen measured in flue gas, dry basis

To convert ppm NO_x at 3% O_2 to g/GJ: for natural gas, g/GJ 5 ppm 4 1.907
for fuel oil, g/GJ 5 ppm 4 1.808

Table 4. Typical NO_x Emissions Without NO_x Control Equipment in Place

FUEL AND BOILER TYPE		TYPICAL NO_X EMI SIONS (PPM AT 3% O_2)
Natural gas	• Firetube	75-115
	• Package watertube	40-90
	• Field-erected watertube	45-105
No. 2 oil	• Firetube	70-140
	• Package watertube	90-150
	• Field-erected watertube	40-115
No. 4 oil	• Package watertube	160-310
	• Field-erected watertube	140-190
No. 6 oil	• Package watertube	200-360
	• Field-erected watertube	190-330

Although the other GHGs, unit for unit, are much more potent than CO_2 in their effects, the latter is the most important GHG because of its volume. In 1997 it represented three-quarters of Canada's total emissions. Most of the CO_2 is generated by the combustion of fuels, whether for residential, industrial, transportation or electric power generation purposes. So, applying energy efficiency measures that reduce fuel consumption is crucial to reducing CO_2 emissions.

Fuel consumers face a double challenge. One is economic – to get the best value for their fuel budget. The other is environmental – to keep emissions low, at least within legislated limits. Fortunately, what benefits the first objective also benefits the second.

Higher limits are allowed for equipment with a proven higher efficiency than normal and which, therefore, burns less fuel. Provinces and territories are responsible for enforcement and may enact stricter limits. They also have responsibility for determining to what extent the guideline applies to boilers and heaters that are being modified or overhauled.

Emissions of sulphur dioxide (SO_2) and nitrogen oxides (NO_X) contribute to acid rain and, therefore, are also of concern. SO_2 emissions are controlled by limiting the allowable sulphur content of the fuel, but NO_X emissions can be reduced by manipulating the combustion process. Guidelines for new boilers and heaters are presented in **Table 3**, and *An Energy Efficiency and Environmental Primer for Boilers and Heaters* describes the strategies for complying withNO_X regulations.

The Canadian Council of Ministers of the Environment (CCME) issued the *National Emission Guideline for Commercial/Industrial Boilers and Heaters* in Ma rch 1998. It applies to **new** boilers and heaters that use natural gas, distillate oil or residual oil as their primary fuel. However, it does not apply to standby boilers (those fired less than 500 hours per year). Existing boilers and heaters also are not required to meet the Guideline. If a boiler or a heater is overhauled, the CCME suggests that the Guideline applies if

a) the cost of the heater or boiler reconstruction exceeds 50 percent of the current total erected costs; or

b) the reconstruction work involves a burner change and the costs exceed 12.5 percent of the current total erected costs.

One of the many exclusions in the Guideline applies to boilers and heaters having an input capacity less than 10.5 GJ/h (10 million Btu/h). An important point to remember is that emissions credits are allowed when energy efficiency (e.g. of fuel combustion and heat recovery) is improved.

Provinces and territories may adopt the Guideline as a part of their environmental legislation. The applicable provincial and territorial regulations can be obtained from environment ministries. For the full text of the CCME Guideline, contact the CCME at

CCME Documents
c/o Manitoba Statutory Publications
200 Vaughan Street
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Figure 2. Boiler Efficiency Improvement Program

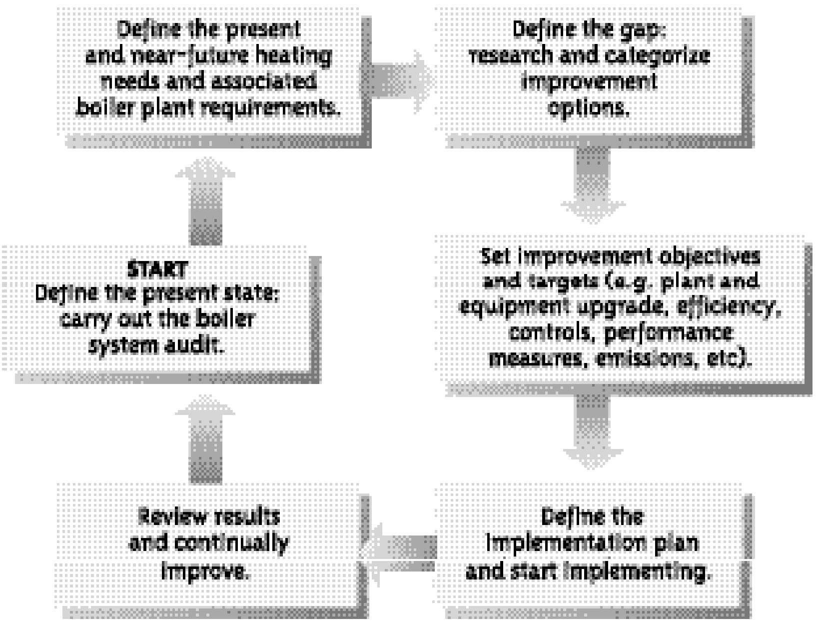
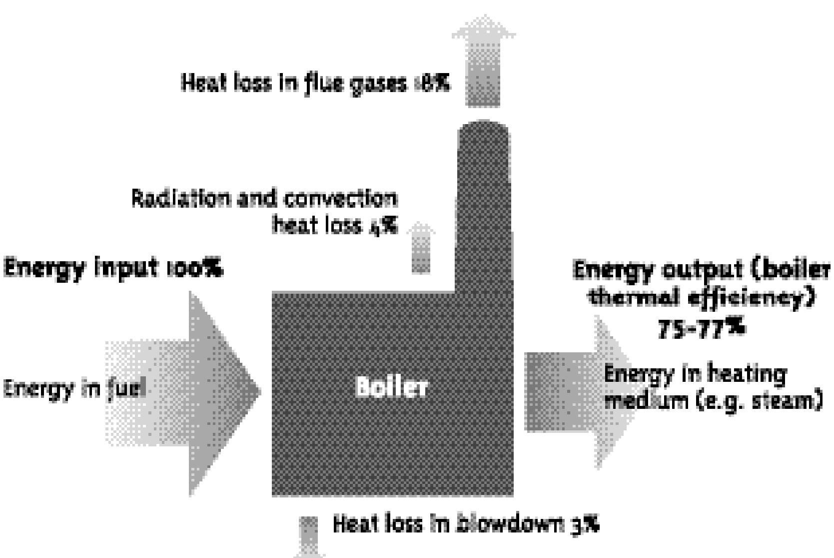


Figure 3. Typical Energy Balance of a Boiler/Heater
(before improvements)



A systematic approach to improving the energy efficiency of boilers – rather than unsystematic improvements – involves a few simplified steps, as shown in **Figure 2**.

A boiler system audit (see the simplified audit checklist in the Appendix) will likely reveal energy losses and inefficiencies. The objective of good energy management is to minimize them. The payoff can be significant in terms of both savings and emissions.

Figure 3 gives a practical hint as to where to direct energy-conservation efforts. However important the economic, efficient operation of the boiler system, it should not be examined in isolation. The following should be checked for further energy-saving and energy-reclaim opportunities:

- the heating needs and energy efficiency aspects of heat-consuming processes, products and equipment; and
- the heat distribution systems (such as steam and condensate).

Heat and energy losses in a boiler system can be reduced in several ways. Some, such as combined heat and power generation (cogeneration), are sophisticated and complex; others can be easily implemented and offer good payback.

***Recent examples:** A chemical plant is saving $500,000 per year by checking for, and replacing, all leaking steam traps. A plywood plant reduced its steamload by 2700 kg/h (6000 lb./h) by upgrading its piping insulation.*

Lowering the system's steam pressure or water temperature to what the involved processes actually need can also reduce energy consumption.

The main categories in the energy efficiency improvement drive are the following.

PROPER BOILER OPERATION

Keep the boiler clean

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 reduces heat transfer dramatically. 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 a result, the flue gas temperature rises – as does the energy cost.

Boilers that burn solid fuels (such as coal and biomass) have a high fouling tendency, whereas those that burn liquid fuels (particularly refined oils) have a low fouling tendency. Maintaining the boiler at peak efficiency requires keeping the boiler surfaces as clean as possible. Large boilers and those burning fuels with a high fouling tendency have soot blower systems that clean the fireside surfaces while the boiler is operating. Brushes and manual lances may also be used. Small boilers, including natural gas-fired boilers and those without soot blower systems, should be opened regularly for checking and cleaning.

Deposits (called scale) on the **waterside of the boiler tubes** can impair heat transfer. They can also reduce boiler efficiency, restrict water circulation and lead to serious mechanical and operating problems. Scale causes the tubes' metal temperature to rise, which increases the flue gas temperature. In extreme cases, the tubes fail from overheating.

Remember, one millimetre of scale build-up can increase fuel consumption by two percent.

Rather than shutting down and draining the boilers to visually inspect the cleanliness of boiler waterside surfaces, waterside conditions can be estimated by testing the boiler water while the boiler is running. Certain water treatment chemicals can then be injected depending on the results. Boiler water is tested daily in small, low-pressure boiler plants and every hour in large, high-pressure plants. The water treatment and testing program is critical to ensuring the maximum efficiency and reliable operation of any boiler plant.

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.

Keep unwanted air out

Effective control of excess combustion air (discussed earlier) 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.

Blowdown water – dollars down the drain

Even treated ("demineralized") boiler feedwater contains small amounts of dissolved mineral salts. Ongoing water evaporation in steam boilers and fresh boiler makeup water increases the concentration of these minerals and leads to scale formation. To prevent this, boiler water must be blown down periodically. Usually, the blowdown is excessive, "just to be sure." The blowdown water is heated, thus wasting heat, water and water treatment chemicals. As minimum preventive measures, test the boiler water periodically for the level of dissolved solids and adjust the blowdown rate.

When the blowdown is done once a day or once a shift, the content of dissolved solids immediately after blowdown is far below the acceptable maximum. If the blowdown can be done more often and with less water – or continuously – the total dissolved solids (TDS) content can be maintained closer to the desired maximum level of safety. The key is good control of TDS. Automatic blowdown control systems with continuous blowdown TDS measurements are available on the market.

Example: *Consider a 23 t/h boiler operating at 860 kPa (about 50 000 lb./h at 125 psig). The blowdown water contains 770 kJ/kg (330 Btu/lb.).*
If the continuous blowdown system is set at the usualfive percent of the maximum boiler rating, then the blowdown flow would be 1150 kg/h containing 885 500 kJ (about 2500 lb./h containing 825 000 Btu). At 80 percent boiler efficiency, this heat requires about 29.7 m^3/h (1050 cu. ft./h)of natural gas, worth about $32,100 per year (based on 300 days per year at $0.15/$m^3$).

Water-heating boiler systems, obviously, do not incur the blowdown costs.

Maximize hot condensate return

A steam and condensate system must be properly designed to eliminate water hammer and reduce losses and maintenance.

Losing hot condensate from a steam boiler system increases water consumption, water treatment chemicals and the thermal energy needed to heat the makeup water. Additional energy is lost in the form of flash steam. This develops when the process pressure, under which the condensate is returned, is released in the condensate return tank. Such losses can be minimized, for example, by submerging the condensate return inlet in the tank or installing a spray condenser fitted on top of the tank.

A **closed-loop system** that delivers steam condensate under pressure to be reboiled practically eliminates losses and needs less steam process equipment.

Example: *A mining company in Quebec recentlyinstalled a closed-loop condensate system. It soon saved 18 percent energy consumption in the boilerhouse compared with a conventional steam condensate open system.*

RECLAIMING BOILER SYSTEM HEAT LOSSES

Flue gas

Herein lies the best opportunity for heat recovery in the boilerhouse.

> A 20˚C (36˚F) reduction in flue gas temperature will improve boiler efficiency by about one percent.

Even with well-adjusted burners providing the minimum flue gas temperatures while achieving complete fuel combustion, the exit temperatures of the flue gas may normally range from 175°C (350°F) to 260°C (500°F). Still, there is ample room to recover some of this heat that would otherwise "go up the stack." Heat exchangers can be used for preheating boiler feedwater (called economizers) or combustion air (air heaters). Economizers typically increase the overall boiler efficiency by three to four percent.

Designers and operators of economizers must consider potential corrosion problems, particularly in fuels containing sulphur. Moisture containing corrosive sulphuric acid is likely to condense on any heat exchanger surfaces that fall below the acid dewpoint. This usually occurs near the inlet of the combustion air or feedwater to be heated.

Each boiler has its specific limit of low flue gas temperature, which should be determined individually if supplementary heat exchange is being considered. Since the flue gas temperatures are lower at lower loads, economizers often have some form of by-pass control that maintains the flue gas temperature above a preset minimum.

Condensing economizers improve the effectiveness of reclaiming flue gas heat. They cool the flue gas below the dew point. Thus they recover both sensible heat from the flue gas and latent heat from the moisture which condenses. Some moisture may be present in the fuel, but most of it is formed by combustion of the hydrogen component of the fuel. (See "Loss due to moisture from the combustion of hydrogen," page 2). Since condensation (and the resulting danger of corrosion) is inevitable, the heat exchanger system must be made of materials that will not corrode. In **direct-contact economizers**, water is sprayed directly into the flue gas. The resulting hot water is collected and used after treatment to neutralize its corrosion potential. (This is an incidental advantage of direct-contact flue gas condensing: it removes particles and acid gases, such as SO_2, from exhaust.) 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.)

Example: *The Hôpital du Sacré-Cœur de Montréal installed direct-contact condensing economizers. The reclaimed heat was used for hot water space heating, fresh air conditioning, laundry, sanitary hot water supply and cooking. It saved 11 percent in natural gasand reduced annual CO_2 emissions by 12 000 t.*

Blowdown heat recovery

Some ways to limit blowdown volume and heat loss were covered earlier. Heat exchangers can reclaim the sensible heat from the blowdown that goes into sewerage for heating boiler makeup water and the like.

BOILER USE AND SIZING

The use and sizing of a boiler system comes up for review when it needs to be replaced or extensively upgraded. Many boiler plants, particularly those used for space heating, face large seasonal or other variations in demand. The efficiency with which boilers convert fuel energy into steam or hot water drops off sharply at low load – when output falls below 40 percent of the maximum capacity rating. It therefore makes sense to select boiler sizes to match varying demand. A small boiler could be installed to operate at close-to-full load for periods of low demand; one or two larger boilers could handle peak loads.

In evaluating a boiler system's use and sizing, consider current and future heating and process steam requirements. More opportunities for improving energy efficiency may be revealed while the process and process equipment are being reviewed.

Example: *Saskatchewan Penitentiary installed two new, smaller boilers, sized for summer load (operating singly) and for joint operation during the winter. Theyreplaced old, oversized boilers, which operated at low fire for most of the year. This solution led to higher efficiency at higher firing rates. Gas savings relative to heated space were 17 percent or 500 000 m³, amounting to \$75,000 per year. Emissions of CO_2 fell accordingly; new low-NO_X burners reducednitrogen oxide emissions by 70 percent.*

COMBINED HEAT AND POWER GENERATION – COGENERATION

Old, inefficient boiler systems often need major, expensive upgrades. In such instances, where there are both electrical and heating demands or where electricity can be profitably sold, a case can be made for cogeneration – combined heat and power generation (CHP). Here lies the greatest potential of CHP systems in Canada – to replace the thousands of small, ageing boilers across the country with units producing both power and heat with greater efficiency than if they were generated separately.

CHP may need more fuel and considerably more capital above that needed to simply meet the heat requirement. But the bonus is the electric energy that CHP provides at high thermal efficiency. This means that the total energy, electrical and thermal, is supplied at lower cost. The high overall energy efficiency of CHP (up to 85 percent), CHP's environmental benefits in reducing CO_2 and NO_X emissions and the ongoing deregulation of the Canadian energy market are stimulating the mounting interest in this rapidly developing technology.

A CHP unit typically consists of a prime mover, such as a gas turbine or piston engine, and a heat recovery steam generator, which is a type of boiler. The prime mover drives an electric generator and sometimes other equipment, such as air compressors. Its exhaust, via the steam generator, provides steam for heating or process use. CHP units are now available in sizes ranging from a few kilowatts to tens of megawatts of output.

Informed, professional advice is required in assessing a potential CHP product.

OTHER CONSIDERATIONS

To optimize the performance and improve the energy efficiency of a boiler system, consider other factors. Some are a matter of regular maintenance and small-scale improvements; others are considered when a major upgrade is required.

Insulation

An audit of a boiler system may reveal that the insulation of the boiler and its piping system is inadequate, in need of repair or missing altogether.

Example: *If only 10 flanges are not insulated on a10-cm (4-in. diameter) pipe carrying steam at 860 kPa (125 psig), the annual heat loss is equivalentto 2450 m^3 of natural gas (worth $370).*

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

Heating needs

Reducing the boiler's steam operating pressure to the minimum needed by the end user, or reducing the temperature of the fluid in the pipes in fluid heating systems, can dramatically affect the energy savings and the quantity of GHGs generated. 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.

Distribution system losses

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. As well, water leaked from the system must be replaced, chemically treated and heated. This is a less apparent, but still expensive, consequence. Heating fluid systems also face this problem.

Example: *Failure of a single 3.2-mm (nominal 1/8-in.) trap in a 690-kPa (100-psig) steam system can lose the equivalent of 11 600 m^3/y of natural gas,worth $1,700.*

Ensure that the distributing pipework is the proper dimension. 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.

Redundant, obsolete pipework wastes energy: because 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 ventilation and air-conditioning needs. Moreover, redundant pipework receives scant maintenance and attention, incurring further losses.

Improper de-aeration of boiler feedwater

Steam with as little as one percent by volume of air in it can reduce the efficiency of heat transfer by up to 50 percent. Pay attention to the de-aeration process as well as to the proper functioning of air vents.

Heat cascading

Plants with several heating needs may have an excellent opportunity to improve their overall energy efficiency with heat cascading. 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 heatboiler to generate low-pressure steam or hot water for space heating and service water. Waste heat is also used for cooling purposes, via an absorption cooler, forexample. Heat can be recovered, stored and reused many ways.*

Approach energy management with an open mind to critically evaluate accepted practices. Some practices may prove to be inefficient. A fresh look or an added awareness, which this chapter aims to supply – combined with imagination and expert assistance – can pay large dividends in reducing energy and costs.

"Energy management opportunities" (EMOs) represents how energy can be used wisely to save money and to limit environmental impacts. This section presents proven ideas that may improve the operation of boiler and heater systems. Choose EMOs from the lists that suit the particular situation and combine them with other energy efficiency measures.

Notes

- The tips for EMOs are presented in three categories. The difference in price between **low-cost** and **retrofit EMOs** depends on the size, type and financial policy of the organization. (Housekeeping is the third category.)
- Due to the variety of possible circumstances, it is impossible to indicate when an EMO will pay for itself. In general, however, **retrofit EMOs** can be expected to have the longest payback.

HOUSEKEEPING EMOS **are energy management actions that are repeated regularly and at least once a year.**

- Run the process equipment using downstream steam (or heating fluid) efficiently by proper production scheduling and maintenance.
- Try to operate the process equipment using downstream steam (or heating fluid) at capacity.
- Shut down the equipment in the process using downstream steam (or heating fluid) when it is not needed.
- 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.
- Maintain good steam quality with a program of regular water chemical treatment and the blowdown regime. Ensure that the feedwater de-aerating equipment and the air vents on the steam piping work properly.
- Monitor the flue gas combustibles and the combustion excess air regularly. Adjust as conditions change.
- Check for and eliminate the entrance of unwanted air into the boiler and flue gas exhaust system.
- Keep burners properly adjusted.
- Maintain the best operating condition of air and fuel controls.
- Calibrate measuring equipment and instruments and tune up the combustion control system regularly.
- Check all the control settings regularly.
- Check and verify the boiler efficiency regularly.
- Monitor and compare the boiler performance-related data to standard and targets regularly.
- Apply routine and preventive maintenance programs to the boiler and heat distribution and condensate collection systems.
- 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.
- Check the integrity of the steam and condensate network (heating fluid supply and return network) and related equipment routinely. Walk through the facility with appropriate detection

equipment (e.g. ultrasonic detector, listening rods, pyrometer and stethoscope), looking and listening for steam leaks. Repair the leaks.

- Set up a steam trap inspection and maintenance program and procedures.
- Inspect the insulation for waterlogging; locate the source of the moisture (e.g. a leaking pipe) and correct the problem.
- Replace or repair any missing and damaged insulation and insulation covering.

LOW-COST EMOS are energy management actions that are done once at a reasonable cost.

- Develop and implement operating procedures and work instructions. Train boilerhouse operators and other employees when necessary. Create an awareness of energy efficiency among all employees.
- Operate the boiler (heater) at the lowest steam pressure (or heating fluid temperature) that meets the needs of the production process. To do this, the process, plant and equipment may need to be modified.
- Review whether the type of facility or industry has combustible by-products (e.g. waste hydrogen, oxygen, carbon monoxide, biogas or hydrocarbon streams, or biomass) that could be used as no- or low-cost boiler fuel supplements. Consider using these by-products.
- Add measuring, metering and monitoring equipment to the boiler and heat distribution systems for fuel, steam, heating fluid, condensate and blowdown flows.
- Optimize the location of sensors. Make sure that the sensor and control devices can be easily accessed for control and maintenance.
- Fit controls with locks to prevent tampering and unauthorized adjustment.
- Consider starting a metering and targeting program to better manage the use of thermal energy (and other utilities) throughout the facility.
- Repair, replace or add air vents (e.g. thermostatic air vents).
- Consider recovering heat from blowdown water. To do this, use flash tanks to generate low-pressure steam from the blowdown (and use it in other heating applications, such as the de-aerator). Use the remaining water in the heat exchanger to preheat makeup water.
- Overhaul steam pressure-reducing stations.
- Consider the economics and means of capturing radiation and convection heat from the boiler shell for pre-heating combustion air.
- Relocate the combustion air intake to a spot where the incoming air has the highest possible temperature year-round.
- Upgrade the fuel and air controls.
- Insulate pipes, flanges, fittings and other equipment with efficient insulation at an economic thickness. Add insulation where it is inadequate.
- Review whether the steam and steam condensate recove ry network (and heating coils and other steam-using equipment) has proper drainage. This will eliminate water hammer, losses and damage.
- Shut down the steam and condensate branch system when it is not needed.
- Look for opportunities to rationalize and streamline the steam and condensate network. Examine current plant-piping drawings, if available, or walk through the facility. First, ensure that the obsolete, unused or redundant piping can be isolated from the rest of the system. Then remove the unnecessary parts.
- Set up a program for steam trap replacement.

RETROFIT EMOS are energy management actions that are done once at significant cost.

- Review whether possibilities exist in the facility and industry to eliminate or scale down the use of steam and heating fluid. If so, modify or adopt a new technology or production equipment (e.g. replace pasteurization with sterile filtration and filling). Or supplement heat usage with other sources, such as a ground-source heat pump, solar walls or thermal storage.
- Replace obsolete boilers with high-efficiency, low-emissions units fitted with new burner technology and heat recovery options suited to the required demand.
- Upgrade the fuel burner. Consider using fuel direct injection (FDI) technology, for example. A full-time FDI regenerative burner (FFR) reduces NO_X emissions by about 90 percent compared with ordinary regenerative burners. The compact FFR burner allows simplification and downsizing, plus a significant reduction in energy consumption and a short payback.
- Install a turbulator in the firetube boiler.
- Convert the burner from oil to natural gas. (Although this may save more money than energy, it has some operational and environmental advantages.)
- Convert from indirect to direct steam heating, where appropriate.
- Convert from steam to heating fluid heating, where appropriate.
- Install an integrated computerized management system for generating and distributing thermal energy.
- Determine whether a waste product is flared off in the operations (e.g. petrochemical, steel and lime industries). If so, consider using it to preheat boiler combustion air or even to operate a micro-turbine generator.
- 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.
- Consider alternate uses for the remaining heat in the flue gas. Use it for space heating, process or drying the product or biomass fuel.
- Consider deploying absorption heat converters (AHC) on the flue gas system.
- Recover heat from waste streams, such as flash steam. Choose from the many options available. Consider incorporating a heat pump into the system to further boost the energy recovery or integrating the new technology of highly efficient compact heat exchangers (CHE) with other processes.
- Consider installing a system for closed-loop pressurized condensate return.
- Hire a qualified contractor to redesign the steam and condensate network to maximize its use. Repipe systems or relocate equipment to shorten pipe lengths.
- If required, consider moving steam generation units (possibly smaller or new) and delivery closer to the steam-using equipment.
- Use the correct pipe size. In heating fluid systems, consider the economics of going to increased pipe diameter versus pumping cost and pressure losses.
- Evaluate the economics of upgrading or adding more insulation. Consider energy cost trends, and consult an unbiased professional. Upgrade insulation cladding.

SAMPLE CHECKLIST FOR AUDITING A BOILER AND HEATER SYSTEM

The following questions will help uncover inefficiencies. Formulate additional questions by the layering technique to get more details.

Management

- Is the use of steam and heating fluid throughout the facility budgeted? Is it monitored? Are there consumption targets?
- If so, are the users of thermal energy accountable for its use? How?
- Are there approved procedures and work instructions governing thermal energy generation, distribution, monitoring and other processes?
- Have employees learned about the significance of energy and utility conservation, and do they use correct practices?
- Are boiler and heater operators involved with the efforts to conserve energy and utilities?
- 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?
- Is there a system for communicating to employees the results of efforts to conserve energy and utilities?

Heat consumption

- Are there procedures for shutting off thermal energy-using production equipment and auxiliary production equipment when not in use?
- Are the above procedures implemented?
- Is steam or heating fluid produced at temperatures or pressures greater than those required by end-user processes, product, plant or equipment?
- 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

- Can a cheaper alternative source for thermal energy be used?
- Can process by-products be used as an auxiliary fuel or fuel supplement?
- If natural gas is used, have the costs of uninterruptible versus interruptible supply been evaluated?
- Is the boiler fitted with dual capability to use natural gas or fuel oil to take advantage of interruptible gas supply contracts?

Fuel storage

- Are heated oil tanks and associated piping adequately insulated?
- Is the external insulation for the above items watertight?
- Is oil heated at the correct temperature?
- Is solid fuel (e.g. biomass) protected against rain? Is it dried?

Boilers and steam distribution

- Is the flue gas free of combustibles?
- Is the boiler efficiency checked on a regular basis?
- Is a proper method for determining boiler efficiency being used?
- Is the efficiency acceptable for the type of boiler and fuel?
- Is the burner operating in the "zone of maximum combustion efficiency"?
- Are the heat losses of the boiler and system known and quantified?
- Is the flue gas checked for combustibles, carbon monoxide and oxygen content on a regular basis? Is the content within an acceptable range?
- How is the excess combustion air managed? How frequently?
- Can unwanted air get into the boiler and the flue stack?

- What type of air or fuel control is used? How is it maintained?
- What type of equipment is used for controlling and monitoring the system? What instruments are used?
- Where is the combustion air intake located?
- Is the combustion air preheated? If so, how?
- Are the NO_x levels in the flue gas known and monitored? Are they within an acceptable range?
- What are the flue gas temperatures at various boiler loads? Are they monitored?
- Is heat being recovered from flue gas? What type? How efficiently?
- Is there any evidence of soot buildup on the fireside surface of the boiler?
- Is there a program for inspecting and removing soot and scale from heat transfer surfaces of the heater and boiler? From process equipment?
- Is the flame in the combustion chamber bright and clear? Does it fill the combustion chamber without encroaching?
- 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?
- How is the blowdown rate controlled?
- Is there a system for recovering heat from the blowdown?
- Is there redundant, oversized or undersized steam piping that causes heat losses? Is there an inspection program for it?
- Are steam lines, flanges, valves and condensate lines adequately insulated? Is the insulation dry and protected against water ingress?
- Is steam or condensate leaking?
- Is the makeup water preheated? If so, how?
- Is the condensate return rate adequate? Has it been verified?
- Is the correct type of steam traps for the application being used?
- Is there an adequate maintenance program for inspecting, repairing and replacing steam traps? How many of the traps are faulty?