

# Chapter 7

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## Steam Systems

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### 7.1 Introduction

Steam systems are vital to commercial, industrial and thermal power plants. In the United States alone, it is estimated that there are over 163 000 boilers in the commercial and industrial sector [1].

The five major steam intensive industries are:

1. food processing
2. pulp and paper
3. chemicals
4. petroleum refining
5. primary metals.

In the U.S. manufacturing sector, these industries account for 71% of the boiler units and 82% of capacity [1]. For instance, in the pulp and paper industry 84% of energy is consumed as steam. Out of which 24% is used in pulping, 20% is used for bleaching and 41% is used for papermaking.

In terms of boiler size, aside from thermal power plants, the chemicals industry, the pulp, paper and oil-refining industries have on average larger boilers than other industries, while not having the most number of boilers. The food industry has the smallest-sized boilers in the industries under discussion. In the commercial property sector, steam systems are also required for heating and refrigeration. However (though numerous), these are (in comparison to the industrial boilers) significantly smaller.

Given the large dependency on steam, in an environment of increasing energy costs and a focus on climate change, increasing steam efficiency allows businesses to be competitive and an opportunity to save energy, water and reduce greenhouse gas emissions.

It is estimated that steam efficiency improvements can reduce a fuel bill by 20–40% [2, 3].

**Case Study: What impact does a 30% improvement in steam efficiency have in the US manufacturing sector?**

If all US manufacturers improved the efficiency of their steam systems by 30%, they would save approximately 2954 PJ\* (2.8 Quadrillion\*\* Btu) of steam energy. This equates to 101 million metric tons of coal, enough to supply the total energy needs of the State of Michigan for a year and reduce CO<sub>2</sub> emissions by 60 million metric tons – and nitrous oxide by 30 thousand metric tons.

Adapted from: U.S. Department of Energy, *Steam Digest* 2000.

\* 1 PJ = Peta Joule = 10<sup>15</sup>J. 29 PJ = 1 million metric tons of coal

\*\* 1 Quadrillion = 10<sup>15</sup> Btu = 10<sup>18</sup>J

The following discussion shows how water conservation can achieve savings in steam systems.

## 7.2 Steam System Principles

The three forms of energy used in industrial processes are as follows.

1. electricity
2. direct-fired heat
3. steam.

Steam is used in a variety of ways, such as

- for process heating and steam tracing
- for pressure control
- for driving mechanical equipment (such as pumps, fans and turbines, and absorption refrigeration)
- as a source of water and heat for process reactions
- for steam jet ejectors to produce a vacuum and component separation (such as in oil distillation)
- to generate electricity.

The wide use of steam is due to its advantages, such as

- low toxicity
- ease of transportability
- high efficiency
- high heat capacity
- low cost relative to other alternatives.

Heat can be stored as sensible heat and latent heat. The advantage of steam is that (unlike other fluids) the majority of the heat is stored as latent heat. Therefore it can be transferred at constant temperature.

As shown in Figure 7.1 a steam system consists of five sections namely

1. pre-treatment
2. steam generation
3. steam distribution
4. end use and
5. steam recovery.

### **7.2.1 Pre-treatment**

As described in Chapter 2, natural waters contain many impurities that are undesirable for steam generation.

These are

- suspended solids
- dissolved solids
- dissolved gases.

Town water normally does not contain suspended matter but contains varying degrees of dissolved solids such as calcium, magnesium, iron, bicarbonates, carbonates and silica, among others.

The presence of calcium, magnesium, silica and iron contributes to scale formation inside the boiler. The thermal conductivity of scale is an order of magnitude less than the corresponding value for bare steel. Even thin layers of scale as seen from Figure 7.2 reduces heat transfer and if left untreated can result in boiler tube failure. Dissolved gases such as oxygen react and corrode boiler internals. Carbonates break down to carbon dioxide and corrode condensate systems.

Therefore, it is necessary to remove these impurities. Pre-treatment systems predominantly consist of filtration, ion exchange and, lately, reverse osmosis systems. Filtration only removes suspended solids. Ion exchange and reverse osmosis systems remove dissolved solids.

There are three types of ion exchange processes. These are

1. water softening
2. dealkalisation
3. demineralisation.

Water softening is the simplest ion exchange process. The softening of water is readily accomplished with a cation exchanger, usually the sodium form of a strongly acidic, sulphonic acid resin that exchanges sodium ions to calcium and magnesium ions.

### Steam System Schematic

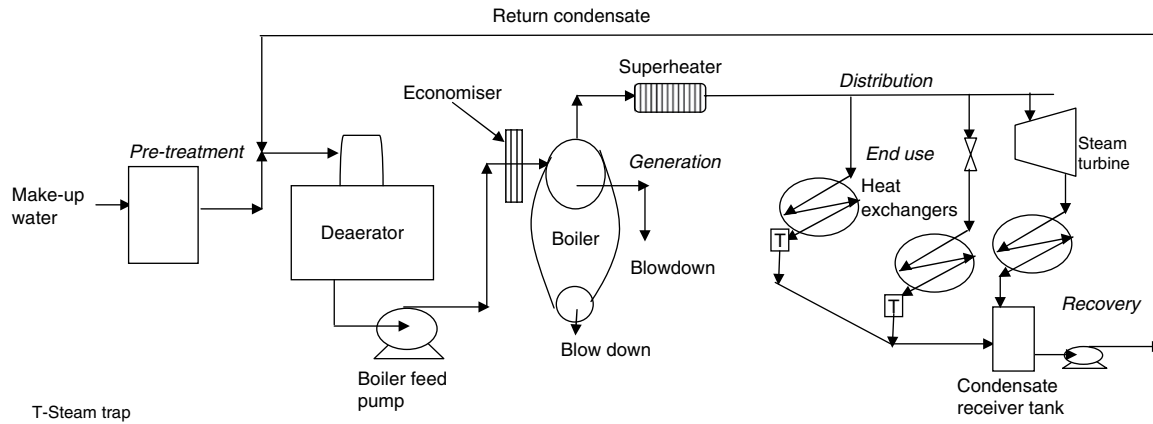


Figure 7.1 Schematic of a typical steam system in an industrial plant

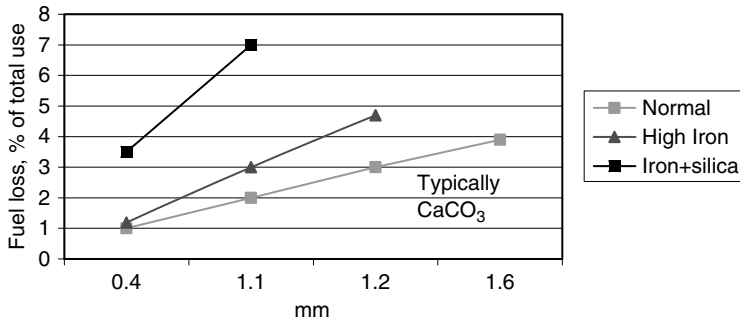
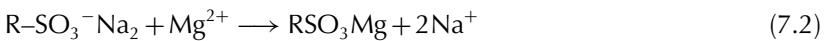
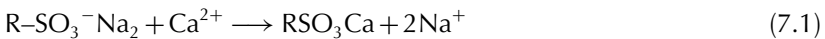


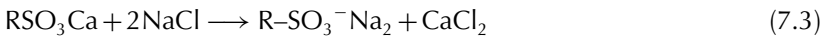
Figure 7.2 Energy loss due to scale deposits

Adapted from U.S. Department of Energy. Industrial Technologies Program, Energy Efficiency and Renewable Energy. *Clean Boiler Waterside Heat Transfer Surfaces*. January 2006.

As shown below:



Since the sodium ions replace the calcium and magnesium ions, there is no reduction in total dissolved solids levels. When the resin is exhausted hardness leakage increases and then the resin needs to be regenerated with a saturated brine solution (NaCl) to bring it back to its original capacity. Water softening is appropriate for low pressure boilers normally less than 4020 kPa (600 psi).



Dealkalisation refers to the removal of bicarbonate and carbonate alkalinity together with hardness.

For high-pressure systems above 4020 kPa (600 psi) removal of all dissolved solids is essential. Demineralisation removes all dissolved ions (both cations and anions) and replaces them with hydrogen (H<sup>+</sup>) or hydroxyl (OH<sup>-</sup>) ions. These units are regenerated with sulphuric or hydrochloric acid and sodium hydroxide. However, a problem with demineralisation is the handling and disposal of spent acids and caustic.

Reverse osmosis (RO) units are used to reduce the burden on ion exchange equipment by removing the majority of dissolved solids. The demineralisation unit then acts as a polisher. Chapter 8 discusses membrane technologies.

Other pre-treatment technologies are cold lime softening and hot process softening. In lime softening, temporary hardness represented by Ca and Mg bicarbonate is precipitated as the insoluble carbonate and hydroxide forms respectively.

Electrodialysis (ED) is the passage of an electric current to drive positively and negatively charged ions towards the cathode and the anode respectively through a semipermeable membrane.

**Table 7.1 Pre-treatment techniques for common impurities**

Substance	Composition	Treatment method
Alkalinity	$\text{HCO}_3^-$ and $\text{CO}_3^{2-}$	Chloride anion exchange, demineralisation, lime-soda softening, Reverse Osmosis (RO), electrodialysis (ED) and chemical neutralisation
Ammonia	$\text{NH}_3$	Hydrogen cycle cation exchange, deaeration and chlorination
Carbon dioxide	$\text{CO}_2$	Deaeration, aeration, chemical neutralisation and membrane contactors
Chloride	$\text{Cl}^-$	Demineralisation, RO and ED
Conductivity	Dissolved solids	Demineralisation, RO and Nanofiltration (NF partial demineralisation), ED and vacuum distillation
Fluoride	$\text{F}^-$	Alum coagulation and anion exchange and RO
Free mineral acidity	$\text{H}_2\text{SO}_4$ , $\text{HCl}$ and $\text{HNO}_3$	Anion exchange, chemical neutralisation, RO
Hardness	$\text{Ca}^{2+}$ and $\text{Mg}^{2+}$	Sodium and demineralisation, NF and RO, EDI, lime-soda softening
Hydrogen sulphide	$\text{H}_2\text{S}$	Aeration and anion exchange using strong base resins
Iron	$\text{Fe}^{2+}$ and $\text{Fe}^{3+}$	Aeration, cation exchange, reverse osmosis, chemical precipitation
Manganese	$\text{Mn}^{2+}$	Aeration, cation exchange, reverse osmosis, chemical precipitation
Nitrate	$\text{NO}_3^-$	Demineralisation, biological treatment, RO and ED
Organics	Various naturally occurring organic acids determined as Total Organic Carbon	Anion exchange, granular activated carbon (GAC), UF, NF and RO
Oxygen	$\text{O}_2$	Deaeration, membrane contactors and chemical treatment
Silica	Dissolved and colloidal silica	Colloidal silica – Hot process softening and Ultrafiltration (UF). Dissolved silica – Strongly basic anion exchange, RO
Sulphate	$\text{SO}_4^{2-}$	Anion exchange and RO
Suspended solids		Filtration, microfiltration (MF), UF and NF

Table 7.1 gives a summary of pre-treatment methods for common impurities and Table 7.2 shows the impact of pre-treatment techniques on water-quality parameters.

Dissolved gases such as oxygen and carbon dioxide are corrosive to carbon steel – and ammonia is corrosive to copper alloys. These effects are exacerbated at elevated temperatures. Therefore, these gases and other non-condensable gases are removed to the lowest practical level in deaerators, deaerating heaters and in membrane contactors.

**Table 7.2 Comparison of effluent quality from commonly used pre-treatment systems**

Technology	Suspended solids	Alkalinity	Hardness	Dissolved silica	Total dissolved solids
Filtration	Reduction close to 100%	No change	No change	No change	No change
Sodium – cycle cation exchange	Prefiltration removes 100%	No change	0–2 ppm hardness in effluent	No change	No change
Two bed strong base/strong acid Demineralisation	Prefiltration removes 100%	100% removal	100% removal	Reduction of 80–90% removal	100% removal
Reverse Osmosis	Removes 100%	At least 90% reduction	At least 90% reduction	Reduction of 90%	Reduction of 90%

In deaerators, low pressure steam is used to heat the boiler feedwater to its saturation temperature, corresponding to the pressure in the deaerator and in the process oxygen is removed. The feedwater oxygen can be reduced to as low as 40–7  $\mu\text{g/L}$ . Following mechanical deaeration, a chemical oxygen scavenger such as sodium sulphite, hydrazine or carbohydrazide (a safer alternative to hydrazine) is used to remove traces of oxygen. The return condensate also joins the deaerator.

Figure 7.3 shows a photograph of a deaerator.



Figure 7.3 A deaerator in an industrial plant

Courtesy of RCR EA Steel Energy Systems Pty Ltd.

### 7.2.2 Steam Generation

From the deaerator the boiler feed water in water tube boilers is pumped through the economiser to the steam drum. The economiser preheats the incoming water further with the exiting flue gases.

Boilers are characterised by

- their application
- configuration
- size
- quality of steam produced.

For example, by application, boilers are classified as

- hot water boilers
- steam boilers
- power boilers.

By configuration boilers can be classified as

- firetube
- watertube
- waste heat boilers
- electric boilers
- hot water boilers
- once-through boilers.

In industry, the most common are firetube, watertube and wasteheat boilers. The average capacity of these are about 10 MW (36 000 MMBtu/hr) [1]. Electric boilers are found in commercial applications such as in hotels and have a capacity less than 300 kW. Hot water boilers are designed to heat water to about 121°C and are mainly used in hotels, schools and hospitals. Once-through boilers are found mainly in thermal power plants.

The focus of this chapter is on fire tube, water tube and wasteheat boilers.

#### 7.2.2.1 Firetube Boilers

Firetube boilers are used principally as heating systems for industrial process steam or as portable steam-generating units. They normally produce 230–68 000 kg/hr (500–150 000 lbs/hr). Typical operating pressures for fire tube boilers are below 1014 kPa (150 psig) [4]. These types of boilers are used in applications where steam demands are relatively small or require only saturated steam. In a fire tube there is only one cylindrical steam drum, which serves to store the water and steam. The hot combustion gases pass inside boiler tubes that are contained within the drum. Heat is transferred to water from the hot flue gases in the fire tubes.

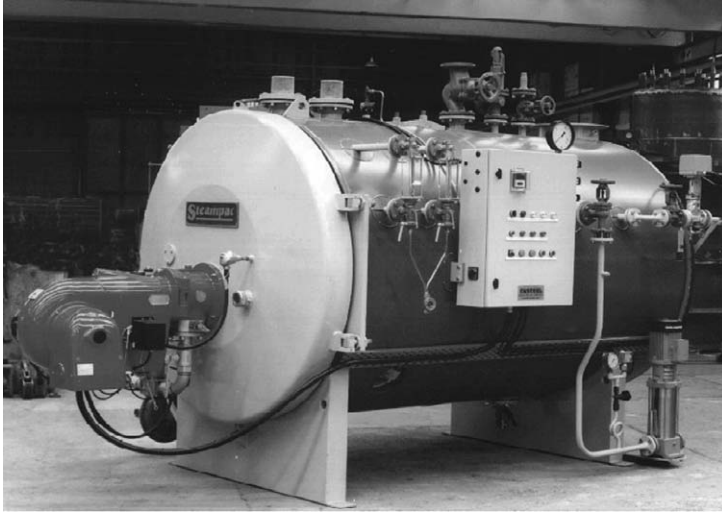


Figure 7.4 Photo of a firetube boiler

Courtesy of RCR EASSteel Energy Systems Pty Ltd.

Figure 7.4 shows a photograph of a firetube boiler. Firetube boilers use gas or fuel oil in their burners. Firetube boilers are easy to operate and are low in cost to run. Given the large body of water in the drum, they can respond to sudden increases in steam demand.

#### 7.2.2.2 *Watertube Boilers*

Watertube boilers, due to their ability to withstand high pressures (as much as 20.3 MPa (3000 psi) or higher), are used in high-pressure systems. In watertube boilers, the boiler water is circulated through the tubes while the exhaust gases are outside passing over the tube surfaces. Heat transfer occurs due to radiation heat as well as conduction and convection from the hot combustion gases.

The circulation in water tube boilers can be forced or natural. Natural circulation boilers operate on the principle of differences in density between cold water (higher density) and a steam/water mixture (lower density). Their capacity may range from as little as 3 MW (10 MMBtu/hr) to 3000 MW (10 000 MMBtu/hr). The larger units are found in chemical, oil refining and steel industries. Water tube boilers can consist of factory fabricated package boilers that use oil or gas as fuel to field erected coal fired boilers which can be several storeys high.

While the initial cost of a watertube will be higher than an equivalent firetube boiler, watertube boilers are capable of high efficiencies and can generate either saturated or superheated steam. The superheater further increases the temperature of the steam. These are particularly suited for high-energy high-pressure systems requiring dry steam – such as in steam turbine

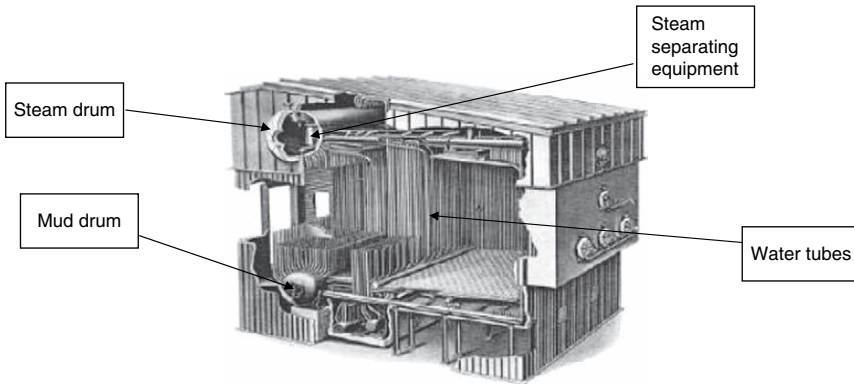


Figure 7.5 A cutaway view of a typical watertube boiler

applications for power generation. Figure 7.5 shows a cutaway view of a typical water tube boiler.

A watertube boiler consists of

- the steam drum
- water tubes
- a mud drum.

The steam drum is the receptacle for steam/water mixture and it separates the steam from the water. The boiler feedwater and chemical dosing line enters the steam drum. The continuous blowdown lines also exits the steam drum. The mud drum (as the name suggests) separates the suspended solids from the water. A bottom blowdown is also located here. The steam drum is bled to control the dissolved solids while the mud drum is bled to remove particulates and sludge. Bottom blowdowns are periodically carried out at predetermined frequencies.

The steam drum continuous blowdown is carried out in accordance with the water-treatment requirements – as dictated by guidelines – such as

- American Society of Mechanical Engineers (ASME) [5]
- British Standard BS 2486 [6]
- Pulp and Paper Institute Guidelines (TAPPI)
- Boiler manufacturers guidelines, such as ABB.

The blowdown water contains useful heat and is therefore a good source of energy to preheat boiler feed water and flash tanks can capture the low-pressure flash steam.

Table 7.3 is a typical guideline for watertube fired boilers.

**Table 7.3 Typical guidelines for Industrial Fired Watertube Boilers**

<i>Drum operating Pressure</i>							
MPa	0–2.03	2.04–3.04	3.05–4.06	4.06–5.07	5.07–6.09	6.09–6.76	6.78–10.14
Bar	0–21	21–31	31–41	41–52	52–62	62–69	69–103
psig	0–300	301–450	451–600	601–750	751–900	901–1000	1001–1500
<i>Feedwater</i>							
pH	8.5–9.5	8.5–9.5	8.5–9.5	8.5–9.5	8.5–9.5	8.8–9.6	8.8–9.6
Total hardness as mg/L CaCO <sub>3</sub>	1.0–0.5	0.5–0.3	<0.2	<0.1	<0.1	ND	ND
Dissolved oxygen as mg/L O <sub>2</sub>	0.02	0.02	0.007	0.005	0.005	0.005	0.005
Oily substances as mg/L	1–0.5	1–0.5	<0.5	<0.5	<0.2	0.2–0.05	0.2–0.05
Total iron max as Fe mg/L	0.1–0.05	<0.05	0.05–0.03	0.03–0.02	0.02	<0.02	0.02–0.01
Total copper max as Cu mg/L	0.05–0.03	<0.03	0.02	0.02	0.01	0.01	<0.01
<i>Boiler water</i>							
TDS max mg/L	3000	2500–1000	<500	300–200	100–50	50	20
pH	10.5–12	10.5–12	10.5–12	10–11	10–11	9.5–10.5	9.5–10.0
Caustic alkalinity mg/L as CaCO <sub>3</sub>	50–300	50–150	25–50	10–20	5–10	2–5	2–5
Phosphates as PO <sub>4</sub> mg/L	30–60	30–40	15–20	15–20	15–20	5–10	5–10
Silica as SiO <sub>2</sub> mg/L	<150	<90	<40	30–10	20–10	8–5	5–2

### 7.2.2.3 Waste Heat Recovery Boilers

Waste heat boilers are unfired boilers and are used in heat recovery applications to generate steam. They may be either watertube or firetube design and use heat that would otherwise have gone to waste.

Ammonia and ethylene plants have unique waste heat recovery boiler designs. For example, in a MW Kellogg ammonia plant, the 101 C heat exchanger is a waste heat boiler which has a *bayonet tube* design. Proper water circulation in these is crucial to minimise tube rupture. Waste heat boilers can sometimes supply close to one-third of the steam demand. They have special requirements, in so much as, being waste heat boilers they may not have sophisticated steam separation equipment and any foaming can decrease steam purity. Heat recovery steam generators (HRSGs) are found in combined cycle cogeneration plants. These are a particular type of waste heat boilers, which generate steam from the exhaust of a gas turbine. Exhaust gases leave the gas turbine at 538° C (1000° F) or higher and can represent more than 75% of the total energy input [7].

## 7.2.3 Steam Distribution System

The steam distribution system distributes steam from the boiler to the end users such as heat exchangers, steam turbines and process vessels. A well-designed steam distribution system ensures that the steam reaches the end users with a minimum of energy losses. Also once the latent heat has been utilised steam condenses to liquid – known as steam condensate. It needs to be collected and returned to the boiler thus minimising water, chemical and energy wastage.

Consequently, proper performance of the steam distribution system requires careful design practices and effective maintenance. The steam pressure needs to match process requirements. The piping should be the right size and insulated to minimise heat loss. The steam balance between the different steam headers should be carefully balanced. The condensate collection system should have adequate drainage and correctly selected steam traps.

Steam traps are essential for the efficient collection of condensate. Steam condensate is hot pure water. If not removed quickly it hampers heat transfer – since a heat exchanger part full of condensate acts as an insulation barrier reducing the physical size of the exchanger.

Steam condensate also contributes to water hammer, resulting in damage to piping and fittings and loss of heat transfer efficiency. A steam trap is a self-contained valve that automatically drains the condensate from steam-containing enclosure while preventing live steam from passing through. Thus the purpose of the steam trap is to remove condensate, air and CO<sub>2</sub> out of the system as quickly as they accumulate.

There are four types of steam traps:

1. thermostatic
2. mechanical
3. thermodynamic
4. fixed orifice condensate discharge traps (FOCDT).

#### *7.2.3.1 Thermostatic Traps*

Thermostatic traps use temperature differential to distinguish between condensate and live steam. This differential is used to open or close a valve. Under normal operating conditions, the condensate must cool below the steam temperature before the valve will open. Common types of thermostatic traps include bellows and bimetallic traps. Thermostatic steam traps are commonly found in low pressure heating systems and are the cheapest type of trap.

#### *7.2.3.2 Mechanical Traps*

Mechanical traps use the difference in density between condensate and live steam to produce a change in the position of a float or bucket. The types of mechanical traps include ball float, float and lever, inverted bucket, open bucket and float and thermostatic traps (F&T steam traps). The F&T steam traps operate on both density and temperature principles. The float valve operates on the density principle: A lever connects the ball float to the valve and seat. Once condensate reaches a certain level in the trap, the float rises, opening the orifice and draining condensate. A water seal formed by the condensate prevents live steam loss. Since the discharge is under water, it is not capable of venting air and non-condensables. When the accumulation of air and non-condensable gases causes a significant temperature drop, a thermostatic air vent in the top of the trap opens to vent air (if air is trapped then it will not allow the steam to enter). Shell and tube heat exchangers require fast draining of condensate and F&T steam traps are ideal for this application. Figure 7.6 shows a cut away of a F&T steam trap.

#### *7.2.3.3 Thermodynamic Traps*

These use the difference in velocity between condensate and live steam to operate a valve. The disc trap is the most common type belonging to this group. The disc steam trap is time-delayed device that has only one moving part, the disc itself. As long as cold condensate is flowing, the disc will remain open. As soon as steam reaches the inlet orifice, velocity of flow increases, it pulls the disc towards the seat thus closing the disc. It is ideal in situations where space is limited, simple and small. It completely discharges all condensate when open and during intermittent operation for a steady purging action. These are not meant for high-capacity condensate discharge unlike F&T. Figure 7.7 shows a cutaway view of a thermodynamic disc steam trap.

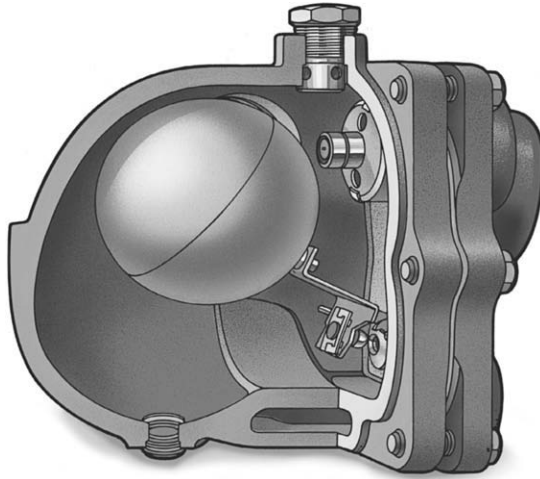


Figure 7.6 A cutaway view of an F&T steam trap

Courtesy of Armstrong International Inc.

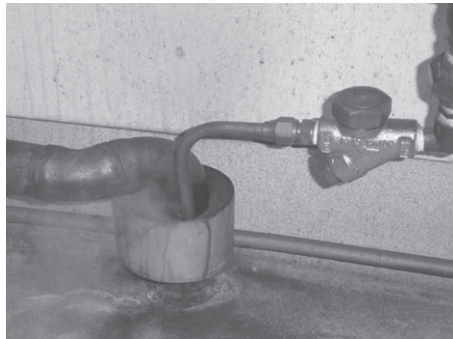
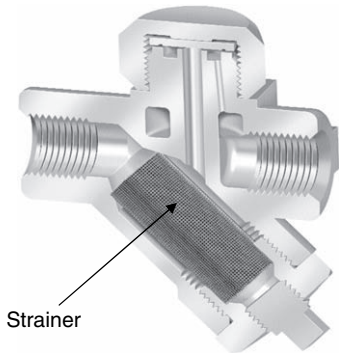


Figure 7.7 Cutaway view of a thermodynamic disc steam trap

Courtesy of Armstrong International Inc.

#### 7.2.3.4 Fixed Orifice Condensate Discharge Traps (FOCDT)

Fixed orifice condensate discharge traps have no moving parts and in principle therefore requires little maintenance. They have a small orifice that allows for the condensate to pass through while preventing the passage of steam. Unlike conventional steam traps these do not reduce the system pressure. They also give a more consistent heat transfer rate. Moreover, when the orifice is blocked it prevents condensate to pass through, which can be easily detected since the line temperature drops. The FOCDT has an advantage

over conventional traps by being more reliable reduces maintenance costs which in turn results in reduced energy consumption.

### Case Study

South Manchester University Hospitals Trust is one of the largest patient care providers in the UK. The Trust replaced 86 traps with FOCDT in their laundry at Withington hospital. The laundry has an annual throughput of 1.8 million kg of linen.

Low priority for maintenance of the steam system led to the hospital trust using an additional 500 kg/hr. The replacement with FOCDT led to the hospital saving 19.2% of steam used in the laundry. Reductions in CO<sub>2</sub> and NO<sub>x</sub> equated to 19% and cost savings of £9,600 per year were realised.

Source: Energy Efficiency Best Practice Programme, *Energy and Cost Savings through the installation of low maintenance steam traps*, Case Study 120. Watford, UK. 2000.

## 7.3 Steam and Energy Conservation Opportunities

From the previous discussion it is evident that there are a number of steam and energy conservation opportunities in steam plants. These are shown in Table 7.4.

Some of these measures are described below.

**Table 7.4 Steam conservation opportunities**

Area	Action
Maintenance	Repair steam leaks
	Maximise condensate recovery
	Install continuous blowdown heat recovery
Operating practices	Minimise vented steam
	Reduce steam system operating pressure
	Improve blowdown practices
	Isolate steam from unused lines
	Reduce excess boilers on standby or install smaller boiler
	Use high-pressure condensate to make low-pressure steam
Water treatment	Reduce deaerator vent steam rate
	Maintain clean boiler heat transfer surfaces
	Minimise blowdown
	Reduce boiler water dissolved solids
	Improve condensate recovery by improving condensate chemistry and preventative maintenance of steam traps

### 7.3.1 Repair Steam Leaks

Steam leaks are often found at

- valve stems
- unions
- pressure regulators
- equipment connection flanges
- pipe joints.

While saturated steam is visible to the naked eye, high-pressure superheated steam is not and poses a safety risk. A typical saving of 1.4% fuel saving is realisable. Table 7.5 shows the steam losses as a function of hole diameter and pressure.

Table 7.6 shows the annual cost of steam leaks from a 1035 kPa (150 psig) steam pressure line as a function of hole diameter.

**Table 7.5 Steam loss kg/hr as a function of pressure and hole diameter**

Hole diameter (mm)	Hole diameter (in.)	Steam Loss kg/hr			
		Steam pressure kPa (psi)			
		104 (15)	690 (100)	1035 (150)	2070 (300)
0.8	1/32	0.4	1	2	–
1.6	3/16	2	6	9	16
3.2	1/16	6	24	34	65
4.5	1/4	14	54	77	147
6.5	1/8	25	95	136	261
9.5	3/8	55	214	307	586

*Adapted from US EPA Steam Challenge.*

**Table 7.6 Cost of steam leaks from 1035 kPa steam pressure**

Size of orifice (mm)	Size of orifice (in.)	kg of steam wasted per year	Total cost per year (A\$/yr)*
0.8	1/32	19,008	171
1.6	1/16	74,304	676
3.2	1/8	297,216	2,710
4.8	3/16	666,144	6,078
6.4	1/4	1,187,136	10,833
9.5	3/8	2,672,352	24,384

\* Steam cost at A\$9/ton.

### 7.3.2 Maximise Condensate Recovery

Optimising condensate return for reuse as boiler feedwater is a profitable means of reducing fuel costs and water usage while increasing boiler system efficiency.

Strategies to recover condensate are to

- maximise condensate return
- reduce steam leaks
- reduce venting of steam
- isolate steam from unused lines
- monitor condensate quality
- minimise waterlogging of pipes.

If steam traps have not been maintained for 3–5 years it is estimated on average 15–30% of steam traps may have failed. Regularly scheduled maintenance should reduce this to fewer than 5% of traps [2]. The dollar impact of poor trap maintenance can be seen from the example cited in Table 7.7.

The industry standard is to carryout inspections of steam traps as follows:

- high pressure 1034 kPa (150 psig) – weekly to monthly
- medium pressure – monthly to quarterly
- low pressure – annually.

Table 7.7 shows the potential water loss from a system that has 1000 steam traps.

As more condensate is returned, less make-up water is required, saving on both water and pre-treatment costs. The high purity of condensate allows for greater boiler cycles of concentration, thus reducing water and energy losses to blowdown. Since condensate is typically around 80°C (176°F) the added benefit of returning hot condensate translates to reduced heated cost of make-up water. Additional savings can also be made in reduced water-treatment chemicals and sewer discharge costs.

**Table 7.7 Estimation of daily water loss from steam traps**

Total number of steam traps	1000
Average steam trap failure rate	20%
Minimum leakage rate from a failed steam trap	10 kg/hr
Estimated number of failed steam traps	$1000 \times 0.2 = 200$
Loss of live steam	$200 \times 10/1000 = 2$ tons per hour
Percentage flash off	10%
Daily water loss, m <sup>3</sup> /d	$= (1 - 0.1) \times 2 \times 24 = 43.2$
Annual cost*	$= 2 \times 24 \times 365 = \$157,680$

\* Steam cost at A\$9/ton

A simple calculation indicates that energy in the condensate can be more than 10% of the total steam energy content of a typical system.

### Water and energy savings from increased steam condensate recovery

Assume that the temperature of condensate is 80° C (176° F) and that the temperature of make-up water is at 15° C (59° F). The steam pressure is 700 kPa. The percentage of heat contained in the condensate can be calculated as:

$$h_c = \text{enthalpy of condensate at } 80^\circ \text{ C (176}^\circ \text{ F)} = 334.9 \text{ kJ/kg}$$

$$h_m = \text{enthalpy of make-up water at } 15^\circ \text{ C (59}^\circ \text{ F)} = 62.9 \text{ kJ/kg}$$

$$h_s = \text{enthalpy of steam at } 800 \text{ kPa absolute (114 psia)} = 2768 \text{ kJ/kg}$$

$$\begin{aligned} \text{Heat remaining in condensate} &= (h_c - h_m) / (h_s - h_m) \% \\ &= (334.9 - 62.0) / (2768 - 62.9) \times 100 \\ &= 10.1\% \end{aligned}$$

### Worked example

Assume that the steam system returned an additional 2 ton/hr of condensate at 80° C. The plant operates for 8000 hrs annually with an average boiler efficiency of 82%. The temperature of make-up water is 15° C.

The water usage charges is \$1.00/m<sup>3</sup> and the sewer usage charge is \$1.00/m<sup>3</sup>. The cost of water treatment is \$2.00/m<sup>3</sup>. The gas cost is \$9.00/GJ. Assume a 10% flash steam loss. Calculate the overall annual savings.

Annual water, sewage and chemical savings = (1 - flash steam fraction) × (condensate load in tons/hr) × Annual operating hours × (total water costs \$/m<sup>3</sup>)

$$= (1 - 0.1) \times 2 \text{ tons/hr} \times 8000 \text{ h} \times \$4/\text{m}^3 = \$57\,600/\text{yr.}$$

**Annual Fuel Savings** = (1 - Flash steam fraction) × Condensate load tons/hr × Operating hours × Make-up water temperature rise × Gas costs in \$/GJ / Boiler efficiency

$$= (1 - 0.1) \times 2 \text{ tons/hr} \times 8000 \text{ h} \times (80^\circ \text{ C} - 15^\circ \text{ C}) \times \$9/\text{GJ} / 0.82 = \$10\,273$$

Total Annual Savings due to return of an additional 2 tons/hr of condensate = \$57 600 + 10 273 = \$67 873.

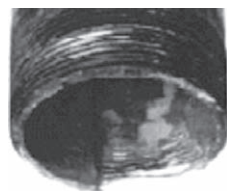
### 7.3.2.1 Condensate Quality and System Protection

Corrosion in condensate systems can limit the quality and quantity of returned condensate because, dissolved and insoluble iron and copper, oil and grease can deposit on boiler heat transfer surfaces. This reduces heat transfer efficiency and could cause premature tube failure.

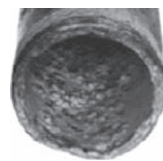
Dissolved gases in condensate such as  $\text{CO}_2$ , Oxygen ( $\text{O}_2$ ) and ammonia ( $\text{NH}_3$ ) contribute to general (and pitting) corrosion of process equipment, lines and tanks. The major source of  $\text{CO}_2$  is the breakdown of feedwater bicarbonate and carbonate alkalinity in the boiler. In water,  $\text{CO}_2$  forms carbonic acid and since condensate is extremely pure even small quantities of carbonic acid can significantly depress the pH to 4.5–5.5. A classic indication of carbonic acid attack is shown in the photo on the left of Figure 7.8. The higher the temperature the more aggressive the acid is to ferrous metals. In the presence of  $\text{O}_2$  the resulting corrosion rate can accelerate 10–40 times faster than the rate of either gas alone [8]. Oxygen causes pitting attack and this is shown in Figure 7.8 photo on the right.  $\text{NH}_3$  is corrosive to copper and copper alloys. The corrosion by-products get carried to the boiler and deposit in boiler tubes. This in turn reduces heat transfer and the usual remedy is to dump the condensate.

A better way is to reduce corrosion by the addition of chemical inhibitors or using a magnetic filter. Condensate corrosion inhibitors known as neutralising amines react with the  $\text{CO}_2$  and elevate the pH to 8.8–9.2. The most common is amine-based organic compounds such as morpholine and cyclohexylamine. Filming amines also protect condensate systems by forming a film and preventing the oxygen to attack the pipe interior. Magnetic filters remove particulate iron in condensate streams. They typically remove 95% of magnetite present [9]. In food plants due to food safety considerations, only a very limited number of neutralising amines can be used, magnetic filters are commonly used to remove the iron in steam condensate.

Condensate can get contaminated from process fluids. When this happens, the condensate needs to be segregated from the clean condensate. Contaminants commonly found in condensate range from sugars, hardness



Carbonic acid attack showing the metal thinning.



Pitting corrosion due to oxygen attack.

Figure 7.8 Corrosion of condensate due to carbonic acid and oxygen

Courtesy of GE Water and Process Technologies.

leakage, fibrous matter, animal fats, grease, naphtha, kerosene, hexanes and fatty acids, among others.

The most common is oil contamination. If left untreated the oily condensate contributes to foaming and sludge deposits in the boiler. Therefore, it is common practice to dump this source of water. The most immediate step is to eliminate the contamination by fixing leaks. If the contamination is severe, then dumping the condensate may be the short-term answer. However, there are technologies to effectively treat oily condensate. These technologies are described in Chapter 8.

#### 7.3.2.2 *Minimise Water Logging of Pipes*

Incorrect location of the steam trap can cause water logging of pipes and result in loss of output, water hammer and erosion of pipes. When two or more vessels are connected to the same pipeline and share a common steam trap known as group trapping, it can lead to water hammer.

It is important to ensure that the pipes are sloped correctly to minimise water hammer. The main should have a slope of 12.5 mm (1/2 in.) in 3 m (10 ft) in the direction of the steam flow. Also ensure there are sufficient steam traps in risers and along horizontal lines and unused steam lines need to be isolated.

#### **Case Study**

A large specialty paper plant reduced its boiler make-up water rate from about 35% of steam production to between 14 and 20% by returning additional condensate. Annual savings added up to more than US\$300 000.

Source: US Department of Energy. Steam Tip Sheet Number 8. *Return condensate to the boiler*. June 2001.

### **7.3.3 Minimising Boiler Water Blowdown**

#### 7.3.3.1 *Blowdown Control*

Proper control of blowdown is a critical part of boiler operation. While insufficient blowdown may lead to deposits and carryover, excessive blowdown will waste water, heat and chemicals. All boiler feedwaters contain some solid impurities. When the feedwater is evaporated in a boiler, steam is formed from the water, leaving the solids behind. As a result, the solids gradually build up in the boiler water. To control these solids, boiler water is removed (i.e. blown down) and replaced with lower solids feedwater.

To keep the solids from building to unacceptable levels, the amount of solids removed by blowdown must equal the amount brought in with feedwater as shown in Figure 7.9. The quantity of blowdown depends on both the amount of feedwater solids and the level of solids that can be tolerated in

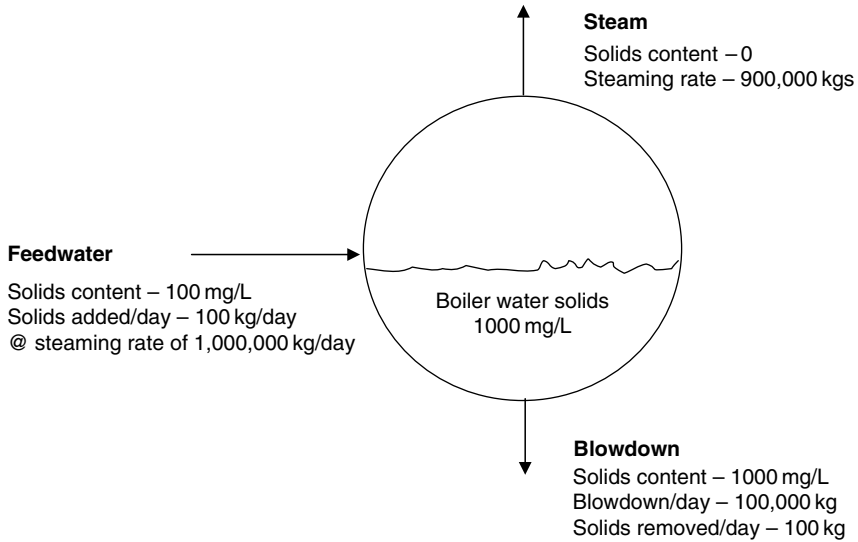


Figure 7.9 The balance between incoming solids with boiler concentrations

a particular boiler – based on the pressure of the boiler as per the guidelines recommended by manufacturers or national standards (Table 7.3).

Minimising boiler water blowdown will reduce water, chemicals and energy costs. On the other hand, increasing solids in the boiler water can cause steam contamination.

The optimum blowdown rate is a function of

- boiler type
- boiler pressure
- water treatment chemistry
- make-up water quality.

Blowdown rates for softened water can be around 5% and for demineralised makeup – about 1%

Blowdown percentages is calculated as

$$\% \text{ Blowdown} = \frac{\text{volume of blowdown water}}{\text{volume of feedwater}} \times 100 \quad (7.4)$$

or

$$\% \text{ Blowdown} = \frac{\text{conductivity of feedwater}}{\text{conductivity in boiler water}} \times 100 \quad (7.5)$$

The second equation shows that per cent blowdown increases as (a) feed-water solids increases and (b) boiler water solids decrease.

There are four basic ways to minimise boiler blowdown. These are

1. improve boiler blowdown control
2. alter treatment chemicals to minimise feedwater conductivity
3. improve boiler feedwater quality.

Examining each alternative enables an assessment of potential savings.

### **1. Improve boiler blowdown control and install automatic blowdown control**

The best way to illustrate this is to use an example. The following parameters will apply.

The boiler water conductivity ( $\text{Cond}_{\text{BW}}$ ) control limit is	600–1000 $\mu\text{S}/\text{cm}$
Average $\text{Cond}_{\text{BW}}$ in boiler water is	700 $\mu\text{S}/\text{cm}$
Boiler Feedwater conductivity ( $\text{Cond}_{\text{BFW}}$ ) is	50 $\mu\text{S}/\text{cm}$
Steaming Rate	50 tons/hr
Annual hours of operation	8000
Cost of gas	\$6/GJ

$$\text{Concentration ratio (CR)} = \text{Cond}_{\text{BW}}/\text{Cond}_{\text{BFW}} = 700/50 = 14$$

Based on the conductivity limits of 600 and 1000  $\mu\text{S}/\text{cm}$ , the CR can vary from 12 to 20.

$$\text{Boiler make up} = \text{Steam rate} \times \text{CR}/(\text{CR} - 1) = 50 \times 14/(14 - 1) = 53.85 \text{ tons/hr}$$

$$\text{Blowdown rate} = \text{Make up} - \text{steam rate} = 53.85 - 50 = 3.85 \text{ tons/hr}$$

$$\text{If the average } \text{Cond}_{\text{BW}} \text{ is increased to } 900 \mu\text{S}/\text{cm}, \text{ then the new CR is } \text{CR}_1 = 900/50 = 18$$

$$\text{New blowdown rate} = 50 \times 18/(18 - 1) = 52.94 - 50 = 2.94 \text{ tons/hr}$$

$$\text{Reduction in blowdown rate} = 3.85 - 2.94 = 0.91 \text{ tons/hr}$$

If cost of water is \$1.0/m<sup>3</sup> and sewage charges are \$1.0/m<sup>3</sup> and chemical treatment costs are \$3.0/m<sup>3</sup>, then the annual water and chemical savings = 0.91 × 8000 × \$5.0/m<sup>3</sup> = \$36400/yr.

To achieve these savings strict control of boiler blowdown is required. An automatic blowdown controller will pay for itself in one year.

### **2. Alter the boiler treatment programme to minimise boiler blowdown**

Boiler water treatment chemicals such as phosphate and sulphite add dissolved solids to the boiler. By altering the treatment programme where there is a reduced contribution of dissolved solids from the chemicals the boiler water blowdown can be minimised.

For example, sodium sulphite is commonly added to mitigate against oxygen-induced corrosion in the pre-boiler and after-boiler sections. However, sodium sulphite adds solids to the boiler water. By converting the treatment

programme to a volatile chemical such as hydrazine or its derivatives such as carbohydazide, this is avoided.

### 3. Improve boiler feedwater quality

As discussed, softeners do not reduce the dissolved solids. By converting to a demineralisation system, the dissolved solids are removed completely and the boiler water cycles increase significantly reducing boiler blowdown.

For instance, using the previous example, let

Boiler water conductivity ( $\text{Cond}_{\text{BW}}$ )	700 $\mu\text{S}/\text{cm}$
Boiler Feedwater conductivity ( $\text{Cond}_{\text{BFW}}$ )	50 $\mu\text{S}/\text{cm}$
CR	14

If  $\text{Cond}_{\text{BFW}}$  is decreased to 20  $\mu\text{S}/\text{cm}$ , then, new  $\text{CR} = 700/20 = 35$

If the blowdown is continuous, heat recovery can result in fuel savings.

## 7.4 Calculating the “True” Cost of Steam

Calculating the true steam costs is essential for water and energy conservation projects to correctly reflect the economic opportunities. Incorrect utility costing can lead to poor investment decisions. Good projects can be discarded and bad projects implemented.

To avoid such mistakes plant managers need to use appropriate steam pricing methods, taking into account all the parameters that impact energy costs which includes fuel, condensate, power generation, cooling water, water treatment, labour, maintenance and water and blowdown discharge costs to the sewer.

It is common to use average costs of generation at a particular production rate. The total operating costs which includes all of the above costs are divided by the total amount of steam produced. Whilst this approach produces a convenient benchmark it may not correctly reflect the true picture. This is especially so when there are multiple boilers and steam turbines. Without going into too much detail the cost of generating steam needs to include the following [10]:

- Cost of fuel ( $C_F$ )
- Cost of raw water ( $C_w$ )
- Cost of boiler feed water treatment ( $C_{\text{BFW}}$ )
- Feedwater pumping power ( $C_p$ )
- Combustion air fan power ( $C_A$ )
- Trade waste charges for boiler blowdown ( $C_B$ )
- Ash disposal (for coal fired and bagasse boilers) ( $C_D$ )
- Environmental emissions control ( $C_E$ )
- Maintenance materials and labour ( $C_M$ )

Cost of steam generation =  $C_F + C_W + C_{BFW} + C_P + C_A + C_B + C_D + C_E + C_M$   
 Fuel costs is by far the major cost of steam.

$$C_F = \frac{\text{Fuel cost} \times (h_s - h_{fw}) \times T}{\text{Boiler efficiency}} \quad (7.6)$$

where

Fuel cost is given in \$/GJ (\$/MM Btu)

$h_s$  – enthalpy of steam kJ/kg (Btu/lb)

$h_{fw}$  – enthalpy of feedwater kJ/kg (Btulb)

T – number of hours of operation per year

Overall boiler efficiency is primarily a function of flue gas temperature and will be in the range of 75–85%.

For oil and gas fired facilities the other costs can be approximated as 30% of the fuel costs and therefore the cost of generation is simplified as

$$C_G = C_F(1 + 0.3) \quad (7.7)$$

The above method gives the average cost of generating steam. However, for water and energy conservation projects it is more useful to use the marginal cost of generation since most of the infrastructure is already paid for and the option to save is the incremental cost of gas or oil.

$$\text{Marginal cost} = \frac{\text{Incremental operating cost}}{\text{Incremental steam consumption}} \quad (7.8)$$

It is not the intention of the book to go into the details of calculating the marginal cost of steam since it depends on a number of variables.

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