•••POWER ENGINEERING

Fourth Class

Edition 3.5

Water Treatment

Part B

Unit B-6

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4th Class Edition 3.5 • Part B

UNIT B-6

WATER TREATMENT

UNIT INTRODUCTION

Boilers, and other related equipment, are heat transfer devices that use water as a medium for the transport of heat from its source to its point of usage. Although other heat transfer mediums are sometimes used, water is generally the most effective because of its relative abundance, low cost, and high heat capacity.

However, a boiler can only efficiently transfer heat to water, and separate steam from water, if the quality of the various water sources are within a suitable range. Common issues include scale, sludge, corrosion, and carryover. Neglecting these issues can lead to operational inefficiency, and potentially catastrophic equipment failure. Other equipment, in both the pre-boiler and post-boiler parts of the energy transfer system, is also affected to varying degrees if the water does not meet the expected quality parameters.

The challenge in any water quality control process is that water is a “universal solvent.” As a result, all sources of water contain various natural concentrations of dissolved minerals and gases, in addition to suspended solids and biological matter. The relative amount of each of these impurities varies by geographic location and season. This makes choosing appropriate water treatment a complex decision.

This unit introduces the basic concepts of water treatment, and the various plant systems with particular treatment needs. The following chapters will familiarize the learner with:

- External water treatment (equipment, processes and testing)
- Internal water treatment (problems, feed systems, sampling and tests)
- Condensate treatment (equipment, processes and testing)
- Cooling tower and condenser water treatment
- Recirculating closed-loop treatment (effects, systems, treatments)

UNIT RATIONALE

Under jurisdictional regulations, a Power Engineer is authorized to supervise a power plant, heating plant, or thermal heating system of predefined configurations and capacities. The requirements within this authorization include the care, maintenance, and safe operation of all related equipment within the defined plant.

For systems using water as a heat transfer medium, it is important for Power Engineers to understand how to maintain water quality parameters at every stage of the process. This is critical for managing plants safely and efficiently.

CHAPTER 1

External Boiler Water Treatment

LEARNING OUTCOME

When you complete this chapter you should be able to:

Describe the general principle, methods, and equipment used in preparing raw feedwater for steam production.

LEARNING OBJECTIVES

Here is what you should be able to do when you complete each objective:

1. *Describe typical impurities and their effects on plant and boiler water pre-treatment systems, and their treatment process.*
2. *Describe the equipment requirements for pre-treatment of plant water systems.*
3. *Describe water filtration and the removal of suspended solids.*
4. *Describe the purpose, processes, and equipment used in water softening.*
5. *Describe the theory, process, and equipment used in deaeration.*

CHAPTER INTRODUCTION

In modern society, the expectation is that water supplies are clean and readily available. Increasingly, this has presented significant challenges to those who supply that water. New technologies have improved the efficiency of operating a modern energy plant. This has made the need for more stringent standards increasingly apparent, for both externally supplied and internally treated water.

In an energy plant, water is treated to eliminate or reduce damage to boilers and other components. Damage from poor water conditions includes scale formation, corrosion, carryover, and other equipment damage.

Five common reasons for boiler water treatment are:

1. Prevent scale from forming on the boiler tubes. This scale may create inefficient heat transfer, overheating, and possible tube rupture.
2. Prevent sludge from forming in boiler or steam drums and tubes. This sludge will insulate the metal surfaces, and cause inefficient heat transfer between the furnace and boiler water. It may also cause overheating of tube surfaces or even tube failure.
3. Prevent corrosion or pitting caused by high dissolved gases, such as oxygen; high concentrations of dissolved or suspended solids; or high or low pH levels.
4. Prevent carryover of boiler drum water, and dissolved or suspended solids. This carryover can result from high levels of suspended solids and dissolved gas.
5. Ensure that the required level of steam purity is achieved.

This chapter identifies common externally controlled impurities and conditions in the source water entering an energy plant. It also looks at the steps to take before use in the plant.

A water treatment program is essential to protect a facility's boiler investment. Properly treated water provides:

- Efficient equipment operation
- Increased boiler life expectancy
- Reduced fuel use
- Optimized water use
- Reduced waste
- Considerable savings on maintenance and labour

Installing properly engineered water treatment equipment for the boiler feedwater will also save money on chemicals.

OBJECTIVE 1

Describe typical impurities and their effects on plant and boiler water pre-treatment systems, and their treatment process.

WATER IMPURITIES

The water entering a boiler system may have concentrated levels of impurities that, if left untreated, can result in serious boiler damage. The impurities may originate from the water source itself (such as rivers, lakes, wells, and municipal supplies), or can come from within the plant's systems. In general, the impurities or conditions that are most often identified as important water quality measures include:

- **Suspended Solids**
- **Dissolved Solids**
- **Dissolved Gases**
- **pH**

Any impurity in a boiler can reduce efficiency. Even worse, it can create a dangerous situation that may result in catastrophic failure. In general, the higher the operating pressure of a boiler, the purer the feedwater needs.

Typical problems that result from impurities are:

- **Sludge**, produced elsewhere but carried along by flowing water, will deposit on the boiler heat transfer surfaces.
- **Scale**, formation from salts. These salts have some solubility in the source water, but are totally insoluble under the conditions inside the boiler.
- **Corrosion**, in the hottest areas of the boiler. This includes the water wall, screen tubes, and superheater tubes.
- **Carryover**, from impurities downstream from the boiler. This carryover will negatively affect the purity of the steam that contacts parts of the energy plant that are susceptible to damage, such as superheaters and turbines.

The methods of treating boiler water can be divided into two main categories:

1. External Treatment of the raw water prior to entering the boiler/steam cycle.
2. Internal Treatment within the boiler.

In general, external treatment takes place before the water enters the boiler. This includes treatment of feedwater, which is comprised of condensate returns and make-up water. Internal treatment consists of the addition of specific chemicals that target problematic impurities. External treatment methods will be discussed later in this chapter. Internal treatment will be discussed in the next chapter.

Suspended Solids

Suspended solids are substances that have not been dissolved, but are held or suspended in the water. Clay, sand, silica, and organic material, such as vegetation, are examples of suspended solids. These small particles are insoluble in water but are carried along suspended in the flow. Though they vary in size, they are usually at least 2 μm in size. Particles smaller than this are usually considered to be dissolved solids.

Larger materials, such as tree debris (leaves and branches), can also be present. These materials are not considered suspended solids since they are easily dealt with by using screens. When surface water is used, higher concentrations of suspended solids can be expected (compared to well or municipal water). The concentrations are usually determined as total suspended solids (TSS) by running a given sample of the water through a standard 2 μm filter, then measuring the amount of solids filtered out.

If suspended solids are not removed, they can form deposits within the boiler. These deposits can reduce heat exchange at the tube walls, which in turn can lead to metal failure or under deposit corrosion. Solids in a stream can also lead to erosion of metal surfaces, or can plug-up the equipment. A higher concentration of solids may cause foaming, which results in carryover or priming from the steam drum.

The most common methods of reducing the levels of suspended solids are externally, through gravity settling (**clarifiers**) and pressure filtration. In some cases, when particles are very small and charged (colloidal particles), **coagulation**, and **flocculation** can be used. Boiler blowdown is used to remove suspended solids that have accumulated in the boiler.

Dissolved Solids

Dissolved solids are usually ionic compounds dissolved in water. Occasionally, dissolved solids consist of suspended particles smaller than two microns in diameter.

Ionic compounds with calcium and magnesium cations are called calcium and magnesium salts. These salts are of particular importance, because their presence is associated with water hardness. Calcium and magnesium ions are more concentrated in well or ground water (compared to lake or river water). Brackish water is water containing high dissolved salt concentrations, but less than the concentration of sea water. When conducting hardness tests, calcium and magnesium salts appear as dissolved solids.

The concentration of different ions are often determined with a conductivity probe. The concentration is then converted to parts per million (ppm).

On Track

PPM is equivalent to mg/L for liquids.

The most common dissolved solids of interest include:

a) Calcium salts of:
  - bicarbonate, $Ca(HCO_3)_2$
  - sulfate, $CaSO_4$
  - carbonate, $CaCO_3$
  - chloride, $CaCl_2$

b) Magnesium salts of:
  - bicarbonate, $Mg(HCO_3)_2$
  - sulfate, $MgSO_4$
  - carbonate, $MgCO_3$
  - chloride, $MgCl_2$

If dissolved solids are not removed, they can react chemically with other ions and precipitate on heating surfaces. This results in local hot spots and, ultimately, tube rupture.

Many of the above compounds cause hardness in the boiler water. The main problem caused by hardness is boiler tube scaling. Scaling coats the tubes, which reduces heat transfer efficiency. In extreme cases, scale causes overheating of the tubes and eventual rupture. Impurities affecting hardness have specific treatments:

a) The bicarbonates of calcium and magnesium cause temporary hardness because they will precipitate out of the water at temperatures below the boiling point. These can be removed before they enter the boiler.

b) The sulfates (and other **anions**) of calcium and magnesium cause permanent hardness since they do not precipitate until the water boils, at which point they form hard, dense scale on boiler surfaces.

The removal of contaminants from water, such as silica, can be a challenge. Colloidal silica can be reduced by agglomeration techniques, such as used in a clarifier. Silica ions (Si^{4+}) are much smaller than colloidal silica. As a result, most mechanical removal techniques such as flocculation, clarification, filtration, and flotation are not capable of removing silica ions. Technologies that remove silica are lime softening, reverse osmosis, and ion exchange.

Sludge is formed by the buildup of solids in a confined location of a boiler. Most sludge precipitates from the boiler water before any steaming occurs. Sludge may be controlled by blowing down the boiler mud drum since this is an area where most of the sludge collects.

Sludge and scale reduce boiler efficiency by decreasing the heat transfer from the flue gas. This occurs for two reasons:

1. Scale insulates boiler surfaces, impeding heat transfer.
2. Scale reduces the flow of boiler water by:
    a) Making heat transfer surfaces rough.
    b) Reducing the flow path cross-sectional area, thus restricting the flow of water.

Sludge and scale buildup can therefore lead to boiler overheating.

Dissolved solids may also cause foaming in the boiler. Bubbles or froth actually build up on the surface of the boiler water, and pass out with the steam. Foaming can also be caused by the presence of oils or suspended solids. In severe cases of foam carryover, the produced steam is wetter, and could have higher impurity concentrations.

Dissolved solids are most commonly removed externally using some sort of ion exchange, such as lime **softeners**, **cation** exchangers (using **zeolites**), anion exchangers, and demineralizers. Distillation and reverse osmosis units can also be used.

A number of impurities found in water supplies exist in ionic form. Common ones include chloride, fluoride, iron, and manganese. The treatment of these impurities is usually controlled by external systems, such as filters, demineralization processes, and feedwater polishers.

Dissolved Gases

Dissolved gases are gases that are in solution. Gases, such as nitrogen, ammonia, oxygen, and carbon dioxide, are commonly found when source waters are analyzed. As the temperature increases, the solubility of gases in water tends to decrease, which results in the release of these dissolved gases. The two dissolved gases of primary concern to Power Engineers are oxygen (O_2) and carbon dioxide (CO_2), because of their ability to produce boiler corrosion.

Oxygen produces a very common form of ferrous metal corrosion. This occurs due to improperly treated feed water. While dissolved in the boiler water, oxygen causes pitting. This sort of corrosion is particularly worrisome since it is very localized and hard to spot. The oxygen carried off with the steam can cause condensate line corrosion. In room temperature water (20°C), there can be up to 9 mg/L (or 9 ppm) of dissolved oxygen. As the temperature rises, the solubility drops towards zero, and the oxygen comes out of solution.

Oxygen removal is accomplished by a combination of external and internal methods. Externally, **deaerators** are used. These devices raise the water temperature close to the saturation temperature, using steam as the heat source. An effective deaerator can reduce the dissolved oxygen level to 5 - 10 µg/L (0.010 ppm or 10 ppb). Internal control of dissolved oxygen is discussed in the next chapter.

Water that contains ammonia causes corrosion in copper and copper bearing alloys, particularly in the presence of oxygen. This can have a negative effect on heat transfer surfaces of heat exchangers that use steam as a heat transfer medium.

Carbon dioxide, when dissolved in water, forms carbonic acid. In a boiler, carbon dioxide travels with the steam. When condensate forms, the carbon dioxide dissolves, forming carbonic acid. This causes grooving on the metal surfaces of condensate return lines. As more dissolved carbon dioxide is present, the pH drops.

Deaerators effectively reduce dissolved carbon dioxide levels. Carbonic acid formation in condensate lines can be inhibited by adding neutralizing agents internally to the boiler or (preferably) directly to the steam lines.

pH

Acidic Conditions

Although not necessarily an impurity, boiler water **acidity** can cause serious problems. Acidity is measured on the pH scale. pH is a logarithmic measure of how many H^+ ions are in the water ($pH = -\log(H^+)$, where H^+ is the concentration of hydrogen ions). A solution with a pH of 6 contains ten times more H^+ ions than one with a pH of 7 (H^+ concentration = 10^{-7}), and a hundred times more than one with a pH of 8. The lower the pH value, the more acidic the water is. A high pH value indicates a basic or alkaline solution.

A neutral solution is one whose pH value is 7. Water from a municipal source can be slightly acidic, in the range of 6.75. Water from lakes and rivers tends to be in the range of 6.5 to 8.5. Ground water has a slightly different range of 6 to 8.5. The acidity of source water is most often due to the reaction of CO_2 (from the atmosphere or from bicarbonate ions) with the water, which produces a small amount of carbonic acid.

This reaction, due to the presence of atmospheric carbon dioxide, is shown as follows:

$$CO_2 + H_2O \rightarrow H_2CO_3 \rightleftharpoons H^+ + HCO_3^- \qquad (1)$$

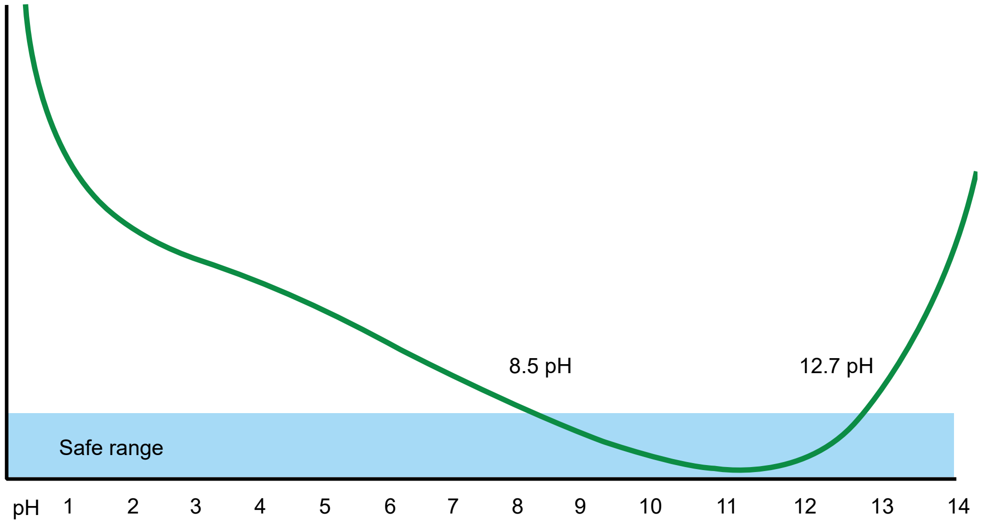
Hard and softened water contains carbonate and bicarbonate salts of calcium, magnesium and sodium. At high temperatures (such as in boiler water), the carbonates and bicarbonates decompose, liberating CO_2. The following uses calcium bicarbonate as an example:

$$Ca(HCO_3)_2 \rightarrow Ca(CO_3)(s) + H_2O + CO_2 \qquad (2)$$

The CO_2 liberated by this reaction enters the atmospheric CO_2 reaction as shown in Equation (1).

The effect of pH conditions on the relative corrosion in boiler steels is shown in Figure 1. A “safe range” of pH is shown between 8.5 and 12.7. Outside this range, corrosion can be significant.

Figure 1 – Relative Corrosion in Boiler Steels vs pH



A pH lower than 8.5 will cause increased boiler system corrosion.

Basic Conditions

While in service, ferrous boiler metal develops a protective type of oxide called magnetite. After this oxide forms, it prevents further oxidation of the boiler heat transfer surface. Magnetite is therefore considered highly beneficial. High pH boiler water will dissolve the magnetite coating, and will eventually cause gouging of the boiler metal (caustic corrosion).

If other conditions exist, such as high boiler metal stress due to large temperature fluctuations, caustic embrittlement may result from high pH levels. Because of the fine intergranular cracking which occurs during embrittlement, it is very difficult to detect. Caustic embrittlement commonly results in boiler metal failure.

High pH boiler water may also cause foaming in the boiler drum.

Most boilers tend to operate at a pH of about 9.5 to 10.5. This balances concerns about corrosion and foaming.

To control the pH of boiler water, monitor, and add neutralizing solutions with a high pH, as required. Sodium hydroxide (NaOH), also known as **caustic soda**, is commonly added to raise pH. To lower pH, the boiler is blown off or its continuous blowdown rate is increased. This removes highly concentrated boiler water, introduces purer, lower pH make-up water, and permits a reduction of pH.

OBJECTIVE 2

Describe the equipment requirements for pre-treatment of plant water systems.

PRE-TREATMENT EQUIPMENT

Boiler feedwater can be sourced from both untreated (surface and well water) and pretreated locations. It is important to know the local water chemistry in order to understand what conditions have to be treated, and how to size the equipment. This information is available in the water analysis for the raw water supply. Most end-user facilities are located in municipal areas, so local water quality reports are available online through the local water utility. If the water report is not available online, contact the local utility to obtain a copy. Municipal water is already quite clean, having already undergone some treatment. However, it does require further treatment for dissolved gases, dissolved solids, and hardness.

Municipal Potable Water Treatment Systems

Municipal potable water systems commonly use three main steps to purify their water:

1. Remove solids
2. Remove pathogens
3. Disinfect

The goal is to provide safe drinking (potable) water that is also aesthetically acceptable.

Municipalities must meet the target requirements of jurisdictional regulation. Table 1 shows some of the most relevant parameters. Municipal systems also test for a large range of other chemicals and bacteria to ensure they are below dangerous levels. (These are not included in Table 1.)

Table 1 – Municipal Water Quality Parameters

	Vancouver, BC	Calgary, AB
Temperature	< 15°C	< 15°C
Turbidity	< 1 NTU	< 0.3 NTU
Free Chlorine	> 0.2 mg/L	≥ 0.2 mg/L
pH	6.5 – 8.5	6.5 – 8.5
Total Dissolved Solids	-----	< 500 mg/L
Hardness (measured)	4 mg/L as $CaCO_3$	132 – 241 mg/L as $CaCO_3$

Regarding the target parameters in Table 1:

a) When the temperature is low, water holds slightly more oxygen. This makes it taste better to the average person. However, greater dissolved oxygen creates problems for the boiler operator.

b) **Turbidity** is a measure of water cloudiness. The turbidity requirement is primarily an aesthetic one. High turbidity also interferes with disinfection efforts. The impurities that cause turbidity may present problems in the boiler.

c) Free chlorine is required to disinfect the water, so that biological impurities do not form or multiply during transportation. However, chlorine is carcinogenic, so its addition must be carefully controlled.

d) The pH of drinking water is expected to be somewhat neutral. However, municipal water is still too acidic for boiler use. To make municipal water suitable for boiler use, the acidity can be neutralized with small amounts of sodium hydroxide (NaOH). However, if made too basic, foaming, gouging and embrittlement can occur.

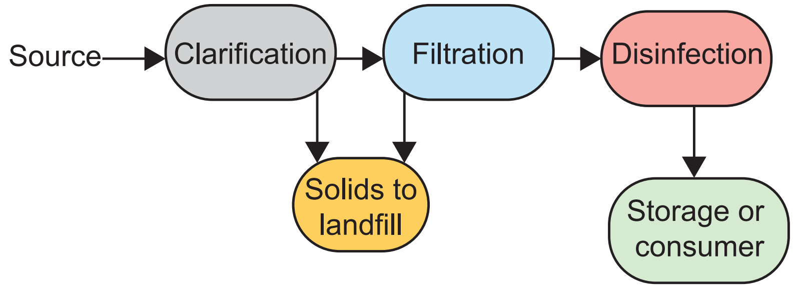
Table 1 shows regional variations. In the Vancouver area, municipal water comes primarily from rain and surface run-off. As a result, it has low total dissolved solids, and is very soft (low hardness). The municipal water source in Calgary has a much higher hardness, and is of extra concern for the boiler operator if used as a source.

A typical municipal water treatment process is shown in Figure 2. The sequence of steps can change from city to city, but generally, all start by removing solids. When water is drawn from a natural source, leaves, branches, and other debris are often drawn along with the water. The water passes through a screen (not shown in Figure 2), and the debris is left behind. These screens are cleaned, either manually or mechanically, on a periodic basis to remove the accumulated debris.

Further removal of solids happens in the clarification step. This usually requires two stages. In the first stage, the larger suspended particles may be removed through gravity separation in a clarifier. Water flows through a large unit (several metres in diameter, and a couple of metres in height) where particles and organic material settle out naturally. The second stage includes a flocculation and coagulation unit, where chemicals are added (such as alum) to promote the **agglomeration** of small particles into larger clumps. The large clumps settle out due to gravity. In some plants, clarification only uses a flocculation and coagulation unit (the initial clarifier is omitted).

At this stage, up to 99% of the particles in the water may have been removed. Many water impurities, such as heavy metals and biological contaminants, are carried along with the particles, and are removed at this step. This reduces the amount of chlorine required later in the process. The collected particles are usually further processed to recover some available water, and then sent to a landfill.

Figure 2 – Municipal Water Treatment Process



In the second step of the process (as shown in Figure 2), there is often a filtration system that removes any remaining small particles. Sand filters are commonly used. Activated carbon can also be used if there are persistent soluble organic constituents that affect taste and odour. The collected particles are sent for further de-watering and disposal along with the clarifier waste stream.

Disinfection is the third step. However, many municipal processes add chlorine earlier in the process, or even have multiple injection points. Disinfection may also include ultraviolet (UV) light or ozone, which has the potential to create fewer health issues over time. Ultimately, some chlorine or chloramine (considered a safer alternative to chlorine) will be used to prevent contamination during transit. Lime may also be added to adjust the pH levels. The water then goes to a storage vessel, or directly to the consumer.

Boiler Feedwater Treatment (Municipal Source Water)

When boilers use municipal water as feedstock, it requires further processing. This will:

1. Reduce hardness (in the form of calcium and magnesium ions)
2. Remove oxygen (and other dissolved gases)
3. Adjust the pH

Care must also be taken to minimize the amounts of iron (Fe), copper (Cu), and silica (SiO_2) in the water. These could all cause deposits. Tables 2 and 3 show recommended ASME guidelines for boiler water quality.

Municipal water also brings with it residual chlorine. In a boiler, as little as 100 ppm could lead to corrosion (such as pitting, cracking, and fatigue). If it is necessary to remove residual chlorine, activated charcoal filters and degasifier towers are used.

Table 2 – ASME Guidelines for Water Quality in Industrial Water Tube Boilers

Boiler Feed Water				Boiler Water		
Drum Pressure (kPa)	Iron (ppm Fe)	Copper (ppm Cu)	Total Hardness (ppm $CaCO_3$)	Silica (ppm SiO_2)	Total Alkalinity (ppm $CaCO_3$)	Specific Conductance µS/cm (unneutralized)
0 – 2070	0.100	0.050	0.300	150	700	7000
2071 – 3105	0.050	0.025	0.300	90	600	6000
3106 – 4140	0.030	0.020	0.200	40	500	5000
4141 – 5175	0.025	0.020	0.200	30	400	4000
5176 – 6210	0.020	0.015	0.100	20	300	3000
6211 – 6900	0.020	0.015	0.050	8	200	2000
6901 – 10 350	0.010	0.010	0.0	2	0	150
10 351 – 13 800	0.010	0.010	0.0	1	0	100

Table 3 – ASME Guidelines for Water Quality in Industrial Fire Tube Boilers (0 – 2068 kPa)

Boiler Water Property	Limit
Silica (ppm SiO_2)	< 150
Total alkalinity	< 700
Free OH alkalinity	Not Specified
Specific conductance (µS/cm) without neutralization	< 7000

Boiler Feedwater Treatment (Non-Municipal Source Water)

For some boilers, makeup water is sourced from a lake, a river, or a well (groundwater). In those cases, pre-treatment is essential before the water goes to the boiler house. The first two stages of the process (clarification and filtration) shown in Figure 2 are still required. Unlike municipal systems, there is no need for disinfection using chlorine. If the water is biologically active, ultraviolet or ozone system are sufficient for disinfection.

If the water has significant suspended solids (normally associated with surface water), then a settling pond can be used initially to economically remove most of the solids. The water enters this large (usually lined) pond, and moves very slowly through it.

The size of the pond depends on the amount of water treated and the required retention time (the time the water spends in the pond). Retention time is usually in days. Gravity pulls the solids towards the bottom, where they are trapped. This leaves cleaner water to continue on its way. To promote settling, compounds such as alum, clay, and polymers may be added.

Table 4 shows some of the common potential problems with boiler water, and lists some of the possible preventative solutions. Subsequent objectives within this chapter will focus on the equipment used to remove suspended solids, hardness, and dissolved oxygen.

Table 4 – Typical Processes used in External Water Treatment

Issue	Problem	Possible Process Solutions
Acidity (low pH)	Corrosion, Scale	Neutralization
Alkalinity	Embrittlement, Foam and Carryover	Lime and Lime-Soda or Zeolite Softening, Anion Exchange
Chloride	Solids creation, increased corrosion	Demineralization, Reverse Osmosis
Dissolved oxygen, carbon dioxide	Corrosion (pitting)	Deaeration, Chemicals
Hydrocarbons	Foaming, Deposits	Coagulation, Carbon Filtration
Hardness (Ca and Mg ions)	Scale	Softening (Ion-exchange, Precipitation)
Iron (Fe) and Copper (Cu)	Deposits	Filtration, Cation Exchange
Silica (Colloidal or Soluble)	Deposits	Deionization, Hot Lime Softening with Magnesium Oxide Addition, Reverse Osmosis, Anion Exchange
Suspended Solids	Deposits (corrosion), sludge, carryover	Clarifiers, Coagulation, Filtration
Dissolved Solids	Foaming	Lime Softening, Cation Exchange, Reverse Osmosis

Note that external treatment for dissolved oxygen will only lower the level to the range of 10 ppb (parts per billion or μg/L). Internal treatment with chemical is necessary to reduce this level to safer values.

OBJECTIVE 3

Describe water filtration and the removal of suspended solids.

The first stage of water treatment is usually the removal of suspended solids. This has the added benefit of removing other harmful substances (e.g. heavy metals), and reducing other treatment costs (such as disinfection).

Suspended solids are particles that are relatively large (greater than 2 microns), and are easy to remove. They do not dissolve as ions, and will either sink with gravity (given sufficient time) or float. As mentioned earlier, if not removed, they will cause significant operational issues, such as deposits, erosion, and plugging of equipment.

While municipal water is likely to have little suspended solids, water drawn from rivers and lakes can have higher levels of suspended solids. This will likely require either a settling pond or a clarifier. Most ground water should not be too high in suspended solids. Suspended solids that do exist in ground water can be removed with filtration.

Settling Pond/Basin

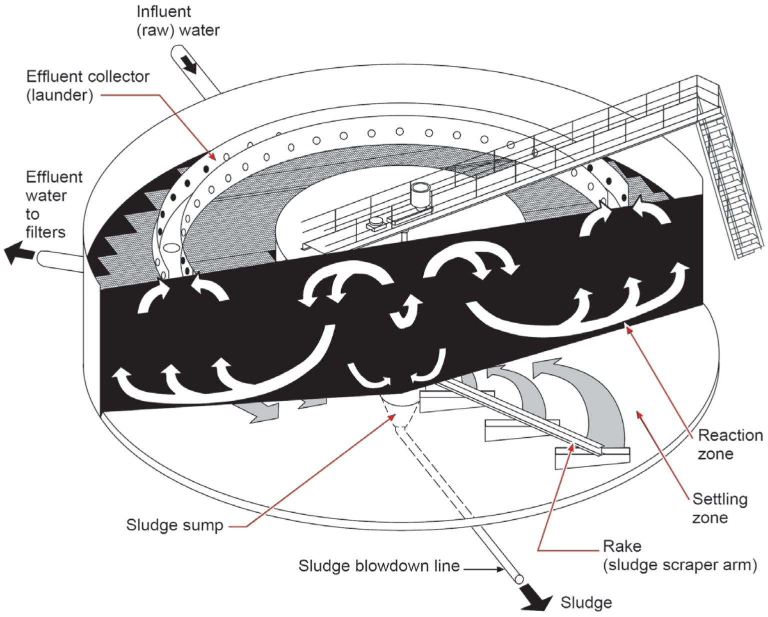
The settling pond or basin will slow or delay the velocity of water. This allows suspended solids to settle, by gravity, to the bottom. Examples of common settling basins are cooling water basins and inlet water basins.

Clarifier

A clarifier is a large settling tank that uses gravity to settle out particles. A settling pond is very similar. Both have water flowing through them, from which suspended solids in the water fall to the bottom. However, with clarifiers, the accumulations of solids are drained from the bottom.

Clarifiers have features that promote the continuous removal of solids deposited by sedimentation. Residence time for the water in a clarifier is in the order of an hour or two, compared to a number of days for a typical settling pond. A common clarifier is shown in Figure 3. Some clarifiers are rectangular in nature, but the same principles apply.

Figure 3 – Schematic of Typical Clarifier



Water is introduced in the center of the clarifier, and flows to the bottom middle section. It then continues upwards to the weirs as shown by the arrows in Figure 3. As the water flows, the particles settle out, and are removed by a rake that moves the sludge to a central sludge blowoff point.

In some cases, the particles are too small to be removed within a reasonable time in a clarifier. Colloidal particles, for example, are less than 1 μm in size, and carry a slight electric charge. This creates natural settling times that can be impractical. To speed the settling time, **alum** (aluminum sulfate), or a synthetic polymer coagulant, may be added to neutralize the particles. This allows the colloidal particles to combine and settle to the bottom of the clarifier.

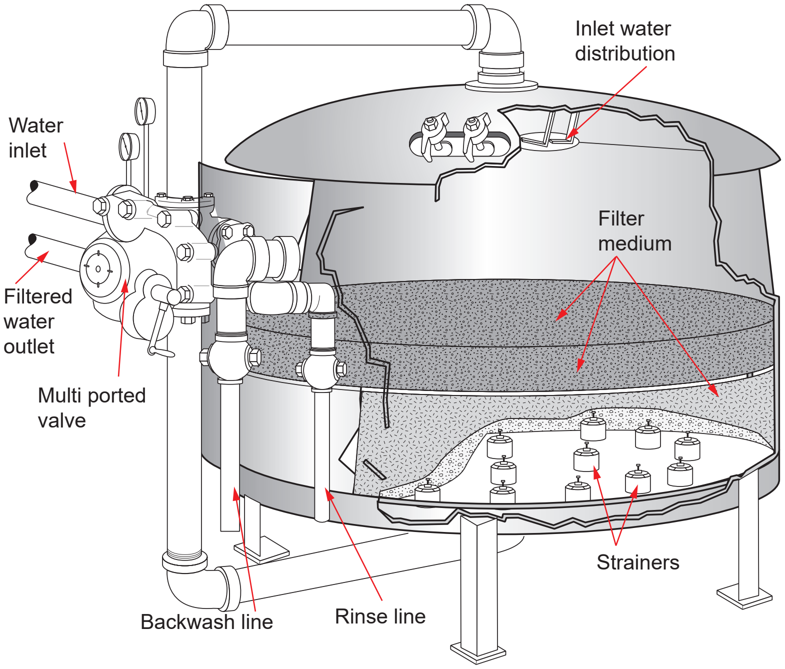
Filtration

Once the initial removal of suspended solids is done, the water usually passes through a filter to remove the last of the suspended particles. The most common types of filters are:

- Pressure filters
- Filter-aid tubular filters
- Cartridge filters
- Activated carbon filters

A schematic of a pressure filter is shown in Figure 4. The water enters at the top, and flows through a distribution plate onto the filter medium. As the water flows downwards through the medium, suspended particles adhere to its surface, and get trapped in pores. The medium is usually a couple of metres deep. It can be sand, anthracite coal, or calcite. The filtered water is collected in the under-bed collection system.

Figure 4 – Pressure Filter



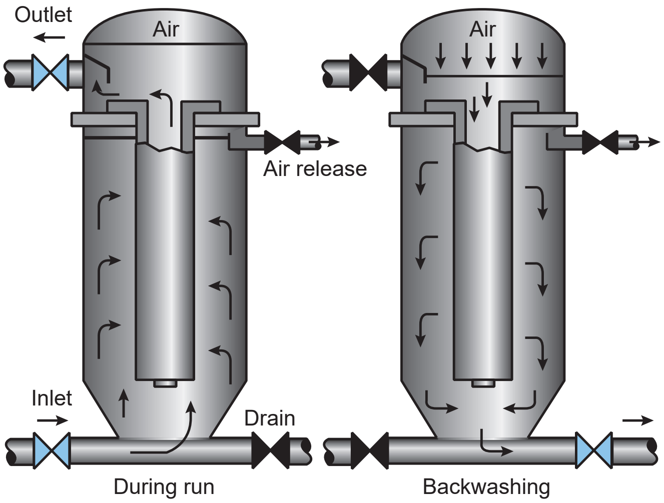
Over time, filters become plugged with suspended particles and must be backwashed. Backwashing involves reversing the flow of water through the filter, thus freeing trapped solids. Care must be taken so that the backwash flow rate is correct. Inadequate backwash flow will fail to expand the bed, so that trapped solids will not come free, making the backwash ineffective. Excessive backwash flow will entrain filter media particles, removing them to waste. Over time, excessive backwash flow rates will remove so much filter media that the filter becomes ineffective. In this situation, the filter must be taken out of service and the filter media replaced.

Effluent resulting from the filter backwash is sent for processing and disposal.

Filter-Aid Tubular Filter

This sort of filter consists of a closed cylindrical housing that contains several screen-type cylindrical tubes. Socks made of Dacron, or a polyethylene filter cloth, cover these tubes. These filters can be quite large, and are similar in concept to an air cleaning baghouse. A schematic of a tubular filter is shown in Figure 5. The left-hand image shows a filter in operation. The right-hand image shows how the filter is backwashed.

Figure 5 – Filter-Aid Tubular Filter



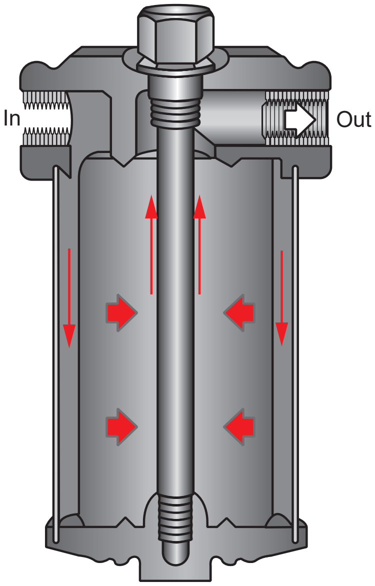
A slurry of filter-aid (usually diatomaceous earth or volcanic ash) is fed through the inlet at the beginning of the filter cycle. The filter-aid pre-coats the tubes. Filter aid is continuously fed while the filter is in service, to prolong the filter run. The additional filter cake that forms increases the filtration effectiveness, until the pressure drop across the filter becomes excessive.

The upper part of the filter housing of the tubular filter is filled with air, which is compressed by the water during the operation of the filter. When the filter starts to clog and requires backwashing, the inlet and outlet valves are closed, and the drain valve is opened. The compressed air in the top of the filter forces water through the tubes in the reverse direction at high speed. This short blast loosens the filter cake so that it drops off and is removed through the drain. Filter cake, depending on the water to be filtered, may last from one week to six months before needing replacement.

Cartridge Filters

Cartridge filters are simple systems that are similar to an oil filter in an automotive engine. A schematic of a cartridge filter is shown in Figure 6. The outer shell can be either steel or plastic. The inner cylinder is usually made of some sort of woven fibers.

Figure 6 – Cartridge Filter



Water flows around the outer space of the filter (between the wall and the filter), and then through the filter. The arrows in Figure 6 show the water passing through the filter to its hollow center. As it does, the filter material catches the suspended solids. The clarified water then goes through the middle of the filter and out to the next stage in the treatment process.

As the filter screens out more solids, the pressure drop across the filter increases. If monitored, this pressure change provides a guideline for the operator. Once the pressure drop is too high (this will depend on the process parameters), the filter cartridge is replaced.

Activated Carbon Filter

An activated carbon filter is often used to remove taste or odours from water. It is also used effectively in industry to remove chlorine, especially from municipal source water. Chlorine must be removed to protect reverse osmosis membranes and ion exchange material. Organics are adsorbed onto the activated carbon, while chlorines are reduced to non-oxidative chlorides. These filters are not very effective against dissolved solids. If used, they should be placed in the process after the removal of solids.

Activated carbon is produced from carbonaceous material, such as coal, coconut shells, peat, and wood. The material is transformed into activated carbon by heating to about 1000°C with steam, and in the absence of oxygen. All the volatiles are stripped, and many of the carbon atoms are removed as they react with the steam. This results in a carbon skeleton having a large surface area (one of the highest surface area to mass ratios known). This property makes activated carbon very useful for adsorption of material. Each teaspoon of activated carbon has a total surface area equal to that of a football field.

Once carbon filters lose their effectiveness, they need to be backwashed and regenerated by heating, or replacement of the carbon media.

OBJECTIVE 4

Describe the purpose, processes, and equipment used in water softening.

WATER SOFTENING

Calcium and magnesium ions are present in water as dissolved solids. Water is considered hard when it contains over 120 ppm (120 mg/L) of calcium or magnesium ions, as $CaCO_3$). This is usually the case when the source is groundwater. For consumers, the main concerns are that hard water is less likely to lather well, and it can leave white residue on faucets and dishware.

For operators, the problems are much more severe. As the water enters the boiler and increases in temperature, the solubility of these ions decreases (which is not the case for most other dissolved solids). As the solubility drops, these ions precipitate out of the solution and form scale. The scale tends to form in high heat areas, and lowers the heat transfer. Scale could possibly lead to under deposit corrosion, and even cause local metal failure.

Clearly, these dissolved solids need to be removed, or treated with a softener prior to water entering the boiler system. To remove the harmful ions, four common techniques are used to soften the water:

- Lime-soda systems
- **Sodium Zeolites**
- Demineralizers
- Reverse Osmosis

Calcium and magnesium ions are unaffected by clarifiers or filters.

Lime-Soda Softeners

Lime-soda softeners use chemical precipitation to remove calcium and magnesium ions.

Lime ($Ca(OH)_2$ or calcium hydroxide) and soda ash (Na_2CO_3 or sodium carbonate) are added to the water. The lime reacts with the impurities that cause carbonate hardness. This reaction leads to the formation of insoluble calcium carbonate ($CaCO_3$).

The soda ash reacts with impurities that cause non-carbonate hardness. This reaction forms magnesium hydroxide ($Mg(OH)_2$) precipitate.

The pH at which these reactions occur is about 11. When these solids form, they become suspended solids, and are no longer dissolved solids. These can then be removed using one of the techniques discussed earlier: clarification, flocculation, or filtration.

Unfortunately, not all of the hardness can be removed in this way. A residual amount of about 50 – 85 mg/L (or ppm) as $CaCO_3$, remains. The water is considered soft at this point, but still needs to be treated to remove even more hardness before being used in boilers.

There are two categories of lime-soda softeners:

1. Hot
2. Cold

Lime-soda softeners do not require prior clarification. Suspended solids are removed along with the precipitated dissolved solids.

In the cold process, the temperature is about 25 – 30°C.

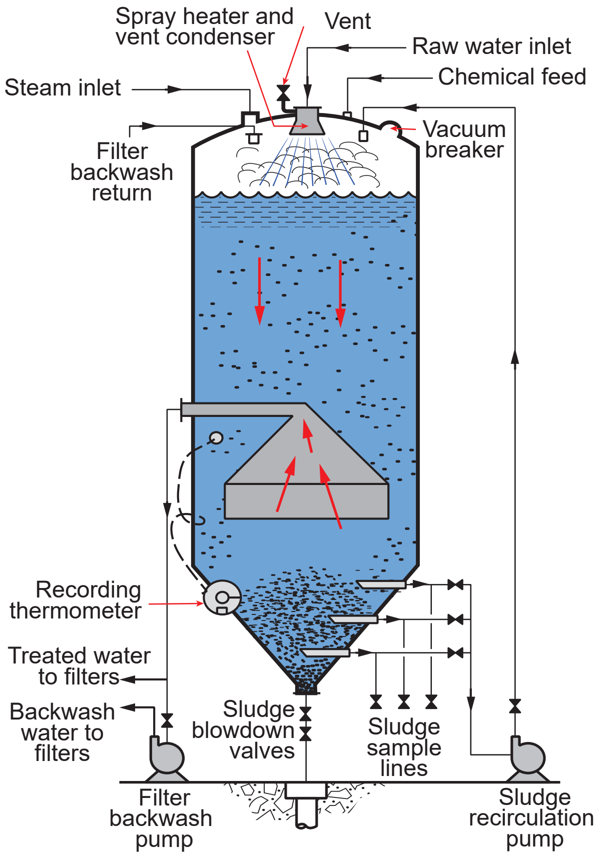
The hot process tends to be more common because it is quicker, and the resulting solids are easier to filter out. In the hot process, the water is at about 95 – 100°C. The hot process can remove silica, whereas the cold process cannot. Some of the silica adheres to the magnesium hydroxide solids that form.

Figure 7 shows a schematic of a hot process lime-soda softener. Raw water enters at the top where it is heated with steam and the lime and soda ash are added.

As the water travels downwards, the chemical reaction occurs, forming sludge (solids that precipitate mixed with water). The sludge collects naturally at the bottom of the tank. Some of the sludge is recycled to the top of the unit to help the precipitates to form. In some cases, especially with cold processes, coagulant is used to help the solids precipitate. The rest of the sludge is periodically removed via blowdown.

The softened water passes through a sludge blanket that helps filter out suspended precipitate. The retention time of the water in the softener should be about an hour.

Figure 7 – Hot Process Lime-Soda Softener



Sodium Zeolite System

Another method to remove hardness is the zeolite softener. These commonplace softeners rely on the principles of ion exchange to soften water. These systems generally incur less capital costs than lime-soda softeners, are easier to control, and the chemicals used are safer for operators. They are so easy to use that many households now have them installed. They can be run mostly on automatic, and take up little room.

Ion-exchange systems can be designed to remove various compounds, such as nitrates, radium, arsenic, and others. For the boiler operator, ion-exchange softeners are designed to remove hardness. Since hardness is caused by magnesium and calcium ions, softening the water simply requires the removal of those ions.

In an ion exchange softener, scale-forming magnesium and calcium ions are replaced with ones that do not produce scale (usually sodium, Na^+). This transforms the dissolved solid salts into sodium bicarbonate ($NaHCO_3$) and sodium sulfate (Na_2SO_4). These are highly soluble, and do not cause scale in the boiler.

Most ion exchangers use zeolites. These very stable solids are insoluble in water. Zeolites have an open cage-like structure that can trap molecules inside. Zeolites can be found naturally, or they can be made synthetically.

Natural zeolites are aluminosilicates, and are used in a wide range of applications, such as water softening, dishwasher detergents, cleaning heavy metal contaminated soils, and even cat litter.

Synthetic zeolites are small polystyrene resin beads, about 0.5 mm in diameter. These can last up to 20 years, but simple erosion and exposure to chlorine can reduce their lifespan.

In water softening, the following chemical reactions occur (Z represents the zeolite):

$$Ca(HCO_3)_2 + Na_2\,Z \rightarrow CaZ + 2NaHCO_3 \qquad (3)$$

$$MgSO_4 + Na_2Z \rightarrow MgZ + Na_2SO_4 \qquad (4)$$

In equation (3), the hardness-causing calcium ions (Ca) are replaced with sodium ions (Na) that were initially attached to zeolites. In reaction (4), the magnesium ions (Mg) are likewise replaced. Unlike lime-soda, zeolite systems can bring the hardness down to zero.

Table 5 shows the typical performance of a sodium zeolite system. The hardness becomes essentially nonexistent, while the sodium concentration increases dramatically. Once the hardness at the softened water discharge rises to a set point, the bed is considered depleted and must be recharged.

Table 5 – Typical Performance of Sodium Zeolite System

Parameter	Concentration in Raw Water	Concentration in Softener Effluent
Calcium, ppm $CaCO_3$	66	0 – 1.5
Magnesium, ppm $CaCO_3$	18	0 – 1.5
Total Hardness, ppm $CaCO_3$	84	0 – 3
Sodium, ppm $CaCO_3$	24	105 – 108
Alkalinity, ppm $CaCO_3$	62	62
Sulfate, ppm $CaCO_3$	30	30
Chloride, ppm $CaCO_3$	16	16
Silica, ppm SiO_2	9	9
Total Dissolved Solids, ppm	166	166

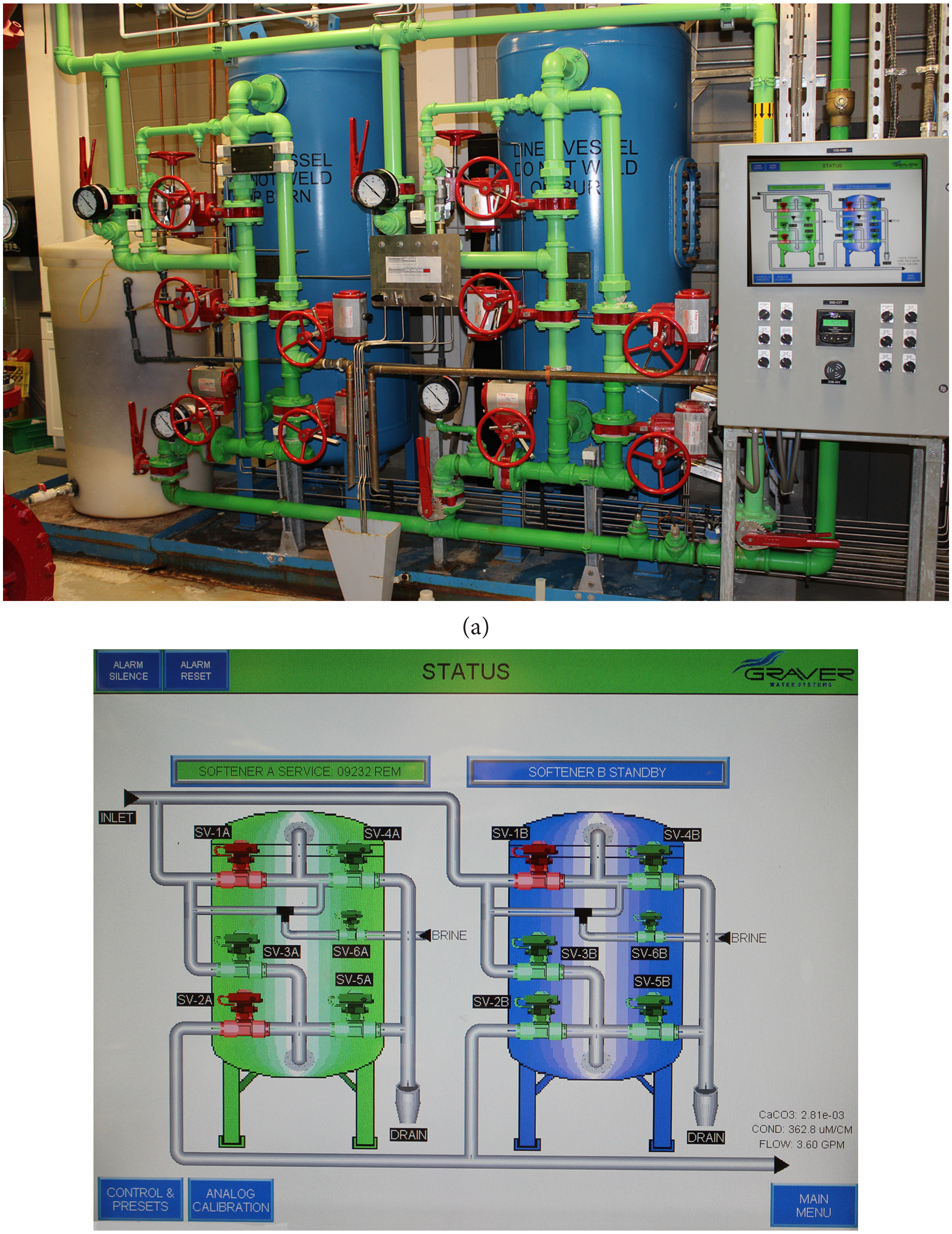
The capacity of a zeolite softener depends on several factors:

- Quantity, type, and condition of exchange material
- Amount of dissolved minerals in the water
- Amount and strength of regenerating solution used
- Mechanical condition of the softener and regenerating equipment

Figure 8(a) shows a photo of a typical zeolite softener installation. They are installed in parallel, so that one unit can regenerate while the other is in service. This ensures that soft makeup water is always available.

The zeolite material is supported on a bed of gravel or anthracite. The hard water flows from the service inlet valve to the top of the unit. The water is then distributed over the bed, and flows downwards through it. Softened water flows out the service outlet, to the condensate receiver, deaerator, or (in some cases) the boiler. Figure 8(b) shows a close-up photo of the softener control system. The computer screen controls this particular softener.

Figure 8 – Zeolite Softener During Operation



CaCO3: 2.81e-03
COND: 362.8 uM/CM
FLOW: 3.60 GPM

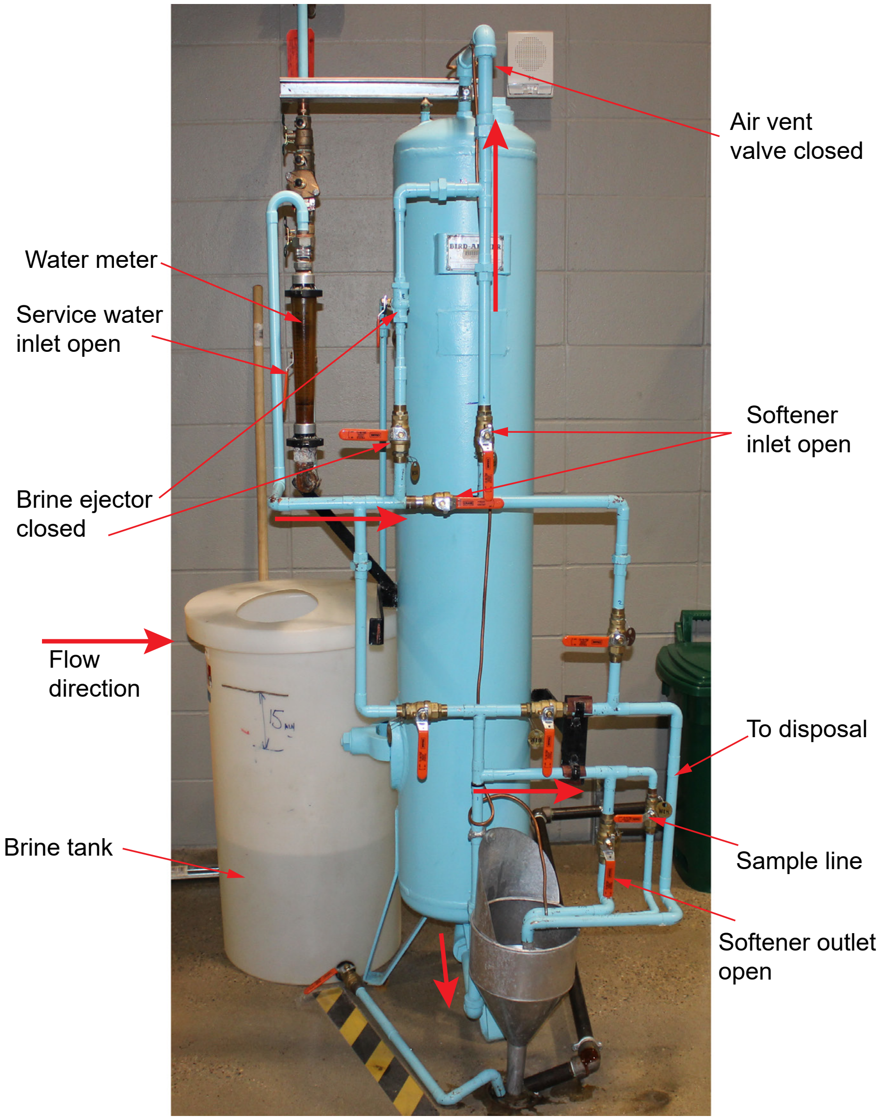
(a)

(b)

An easier to follow labelled photo of a manual zeolite softener is shown in Figure 9. This diagram will be used to describe the operational steps that are computer controlled on the softener in Figure 8.

Figure 9 shows the softener in service. Water enters through the service water inlet. Then, it enters the top of the softener by way of the softener inlet valves. Hard water travels downward through the zeolite material, and soft water leaves the softener through the softener outlet valve.

Figure 9 – In-Service Sodium Zeolite Softener



When the zeolite material has given up all its sodium cations, it must be regenerated before it can soften any more water. This process can take up to 60 minutes, depending on the size and capacity of the unit. The zeolite softener is removed from service and the following procedure is followed:

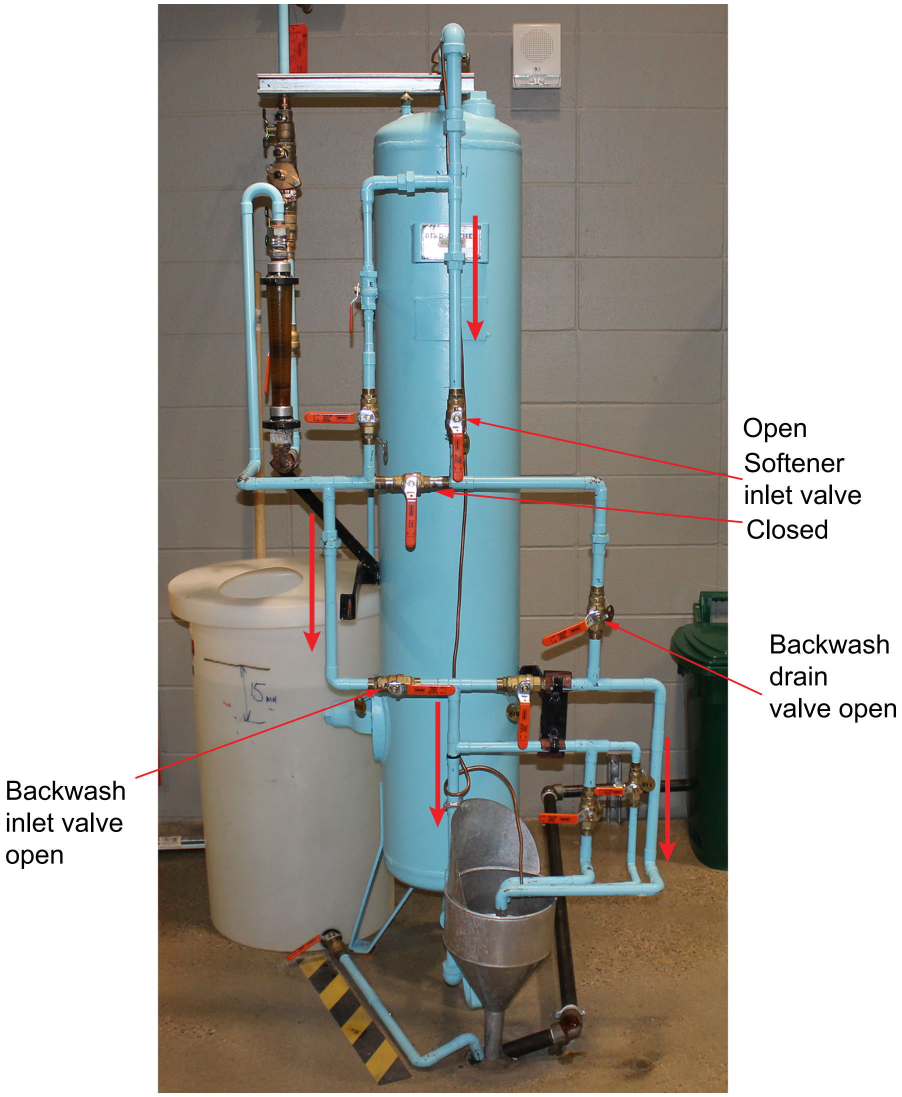
1. Backwashing
2. Brining (regeneration)
3. Slow rinse (displacement)
4. Fast rinse

Backwashing is accomplished by flowing water backwards through the bed (Figure 10). This step expands the volume of the bed (by about 50%), and loosens entrained dirt.

On Track

During operation, the resin bed gets compacted by the force of the flowing water. Backwashing expands the bed, allowing better contact between the brine and the zeolite in the brining step. Backwashing also removes any fine particles that have been deposited in the bed. The backwash should not be too fast. Otherwise, zeolite resin may be carried out with the backwash effluent. Note the backwash outlet valve in Figure 10 is not fully open, in order to restrict the backwash flow.

Figure 10 – Zeolite Softener During Backwash



After backwashing, salt brine is added to the softener vessel. A 10% NaCl solution is injected above the resin bed, and allowed to slowly flow downwards (Figure 11). The exact amount of salt required will depend on the amount and type of zeolite used. This information is usually obtained from the manufacturer.

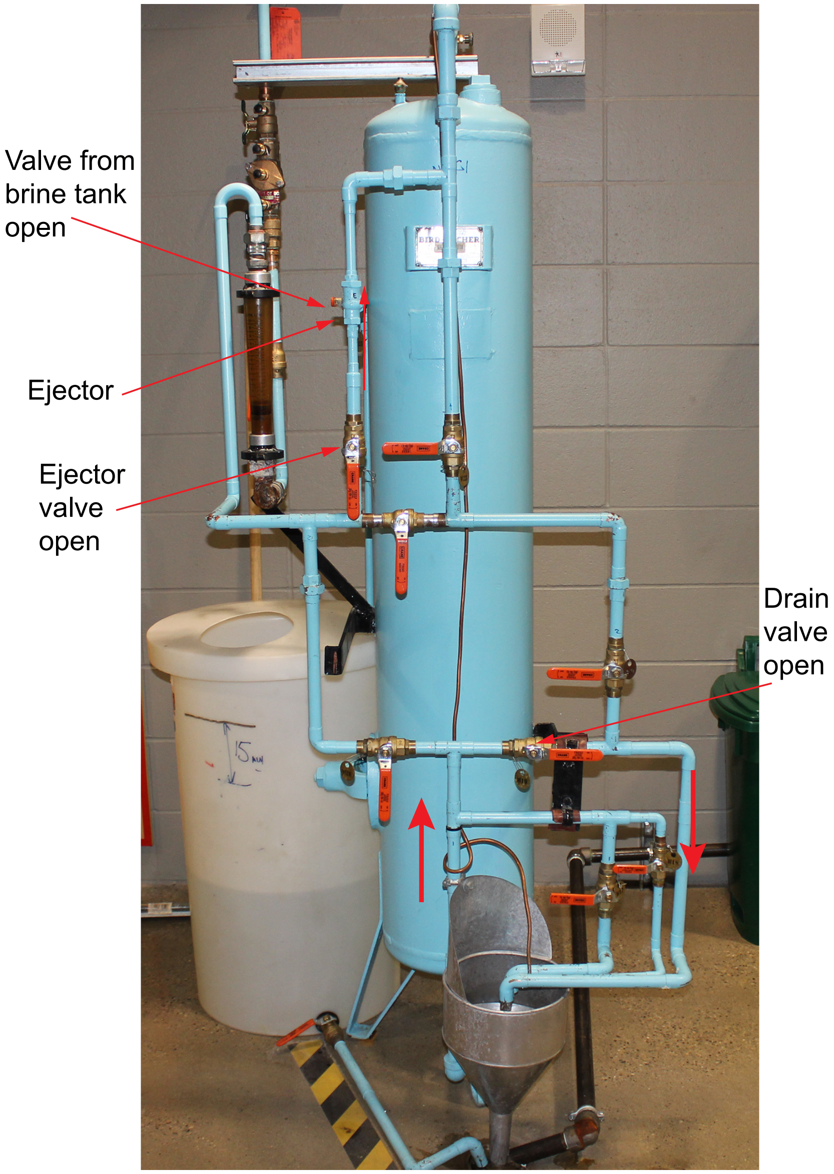
During brining, the following reactions occur:

$$CaZ + 2NaCl \rightarrow Na_2Z + CaCl_2 \qquad (5)$$

$$MgZ + 2NaCl \rightarrow Na_2Z + MgCl_2 \qquad (6)$$

In these reactions, the calcium and magnesium that were trapped during operation are now removed and replaced with sodium (Na). The resulting calcium and magnesium chloride salts are discharged to waste.

Figure 11 – Zeolite Softener During Brining

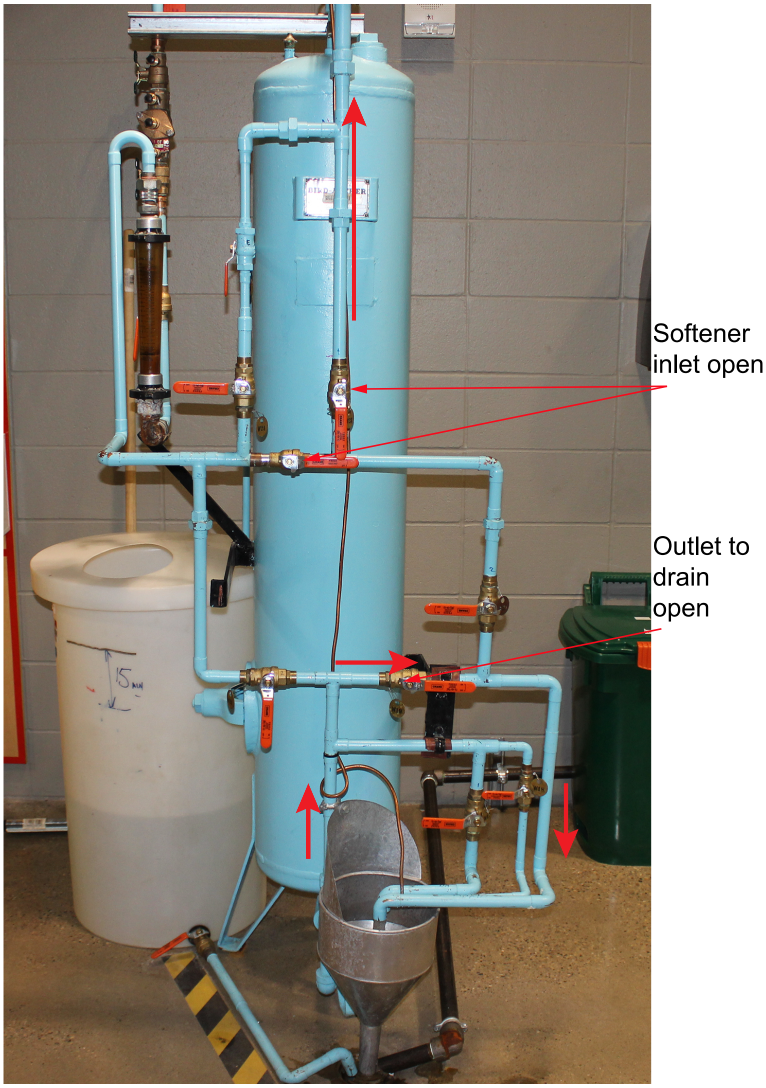


In the third step (Figure 12), the brine is turned off. Water flows downwards, and creates a slow moving plug of water that forces the remaining brine into areas it may not have penetrated earlier.

Figure 12 – Zeolite Softener During Slow Rinse

During fast rinse, the water flow rate is almost doubled. This step completely removes the brine from the zeolite bed (Figure 13). The regeneration can be considered complete when the hardness in the discharge stream during the fast rinse, drops to 1 ppm (or 1 mg/L). Close the outlet to drain valve to put the unit into standby. To put the softener back into service, open the softener outlet valve.

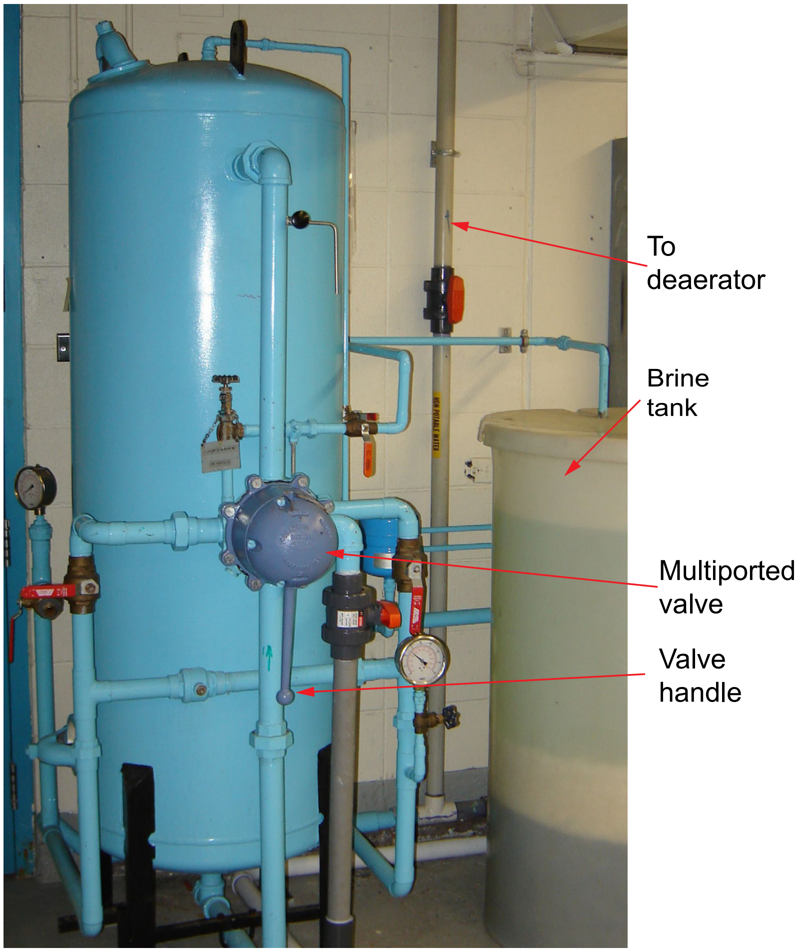
Figure 13 – Zeolite Softener During Fast Rinse



The used or spent brine is often flushed to the sewer. However, ensure that this conforms with local regulations and bylaws. The spent brine may have as much as 40 000 mg/L of chlorides.

Rather than having several valves to control the operation of the softener (as shown in Figures 9 to 13), some softeners have a single master "multi-ported" valve. Figure 14 shows the multi-ported valve in the operation position. The various operations of the softener are controlled by placing a single lever, located on the master valve, into a specific location for each step of the regeneration.

Figure 14 – Master Valve Position



Troubleshooting of Zeolite Softeners

A reduction in the capacity of a softener, or incomplete softening, can often signal a problem. Below is a list of the most common causes of problems, along with their solutions.

1. **A change in water quality**. Surface waters usually have seasonal changes to hardness. This can be either positive or negative. If the hardness increases, the softener capacity (in litres of water treated) will decrease. If the hardness decreases, the capacity will increase. These types of changes are unavoidable, and must be compensated for.

2. **Improper flow rates**. Excessive flow during operation will cause incomplete softening of the water. Excessive flow during backwash could result in loss of zeolite material. The maximum flow rates during all phases of operation should adhere to the manufacturer design specifications.

3. I**mproper brine injection during regeneration**. This results in only partially regenerated beds. If this occurs, make sure that the manufacturer recommended amount and strength guidelines are followed for the brine. The operator should also check the brine tank for proper mixing and delivery of salt, the injector, the float valve in the tank, and the sequence timer.

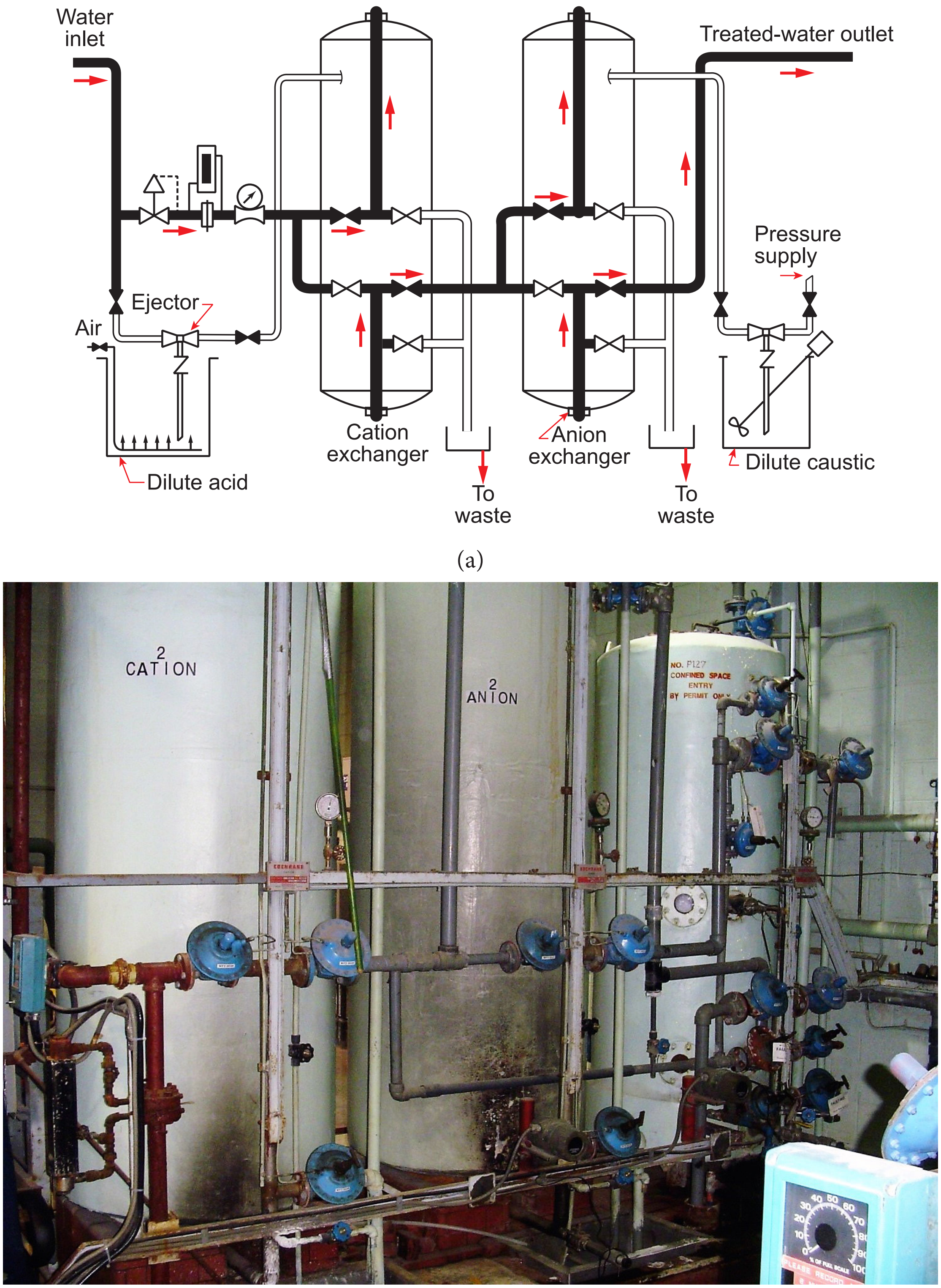
4. **Fouled exchange material.** Contaminants in the supply water such as suspended solids, chlorines, iron, oil, or microbial growths cause reduced output. When identified, the hard water influent must be pre-treated to remove the impurities before it enters the softener.

5. **Mechanical defects.** Broken or plugged baffles, distributors, or collecting headers cause poor water distribution, and channeling of fluids. Leaking valves may contaminate the softened water with raw water. This results in poor softening or reduced capacity. The operator should have an established inspection and maintenance schedule for the unit.
6. **Loss of exchange material by attrition.** With time, zeolite resin cracks, erodes, and breaks up into smaller particles. The amount of eroded or broken zeolite beads expelled from the softener is about 3% per year of the total amount contained in the softener. Periodic replacement of the zeolite resin is therefore necessary.

Demineralizers

Demineralizer units also rely on ion exchange. Two exchange units are installed in series. Figure 15(a) shows two exchangers: a cation exchanger and an anion exchanger. Figure 15(b) shows a photograph of a demineralizer in a power plant.

Figure 15 – Demineralizer Set-up



(b)

Refer to Figure 15(a). The first unit is a hydrogen zeolite cation exchanger. In this unit, calcium, magnesium, sodium, and all other cations are replaced with hydrogen ions (H^+). The influent cations are transformed into acids (sulfuric acid, hydrochloric acid, and carbonic acid), carbon dioxide, and water. Some of the chemical reactions that occur are shown in equations (7) through (9).

$$CaSO_4 + H_2Z \rightarrow CaZ + H_2SO_4 \qquad (7)$$

$$Ca(HCO_3)_2 + H_2Z \rightarrow CaZ + 2H_2O + 2CO_2 \qquad (8)$$

$$2NaCl + H_2Z \rightarrow Na_2Z + 2HCl \qquad (9)$$

The effluent of the cation exchanger is an acidic solution. This solution flows to an anion exchanger. Here, the anions of the acids are exchanged for hydroxide ions (OH^-). The resulting effluent is pure water. Some of the chemical reactions that can occur are shown in equations (10) and (11).

$$H_2SO_4 + Z(OH)_2 \rightarrow ZSO_4 + 2H_2O \qquad (10)$$

$$2HCl + Z(OH)_2 \rightarrow ZCl_2 + 2H_2O \qquad (11)$$

Demineralizers can remove most ions (except for silica). After treatment, the water may have a conductivity reading of lower than 15 µS/cm. These units can be automated, and can handle changes in influent water quality. Because these units are regenerated with acids and bases, they are built with corrosion-resistant materials.

When the exchange materials in the ion exchangers become exhausted, they have to be regenerated in a similar manner as described for sodium zeolite softeners. However, instead of using a brine solution, the cation exchanger is recharged by passing a diluted solution of sulfuric acid through the bed. The cationic impurities that were collected during operation (e.g. Ca^{2+}, Mg^{2+}, and Na^+) are released and replaced by hydrogen ions (H^+). One of the reactions that occurs, as a result, is shown in equation (12).

$$CaZ + H_2SO_4 \rightarrow H_2Z + CaSO_4 \qquad (12)$$

The anion exchanger is recharged by passing a dilute solution of caustic soda through the bed. The anionic impurities that were collected during operation (e.g. $SO_4{}^{2-}$, Cl^-) are released and replaced by hydroxide ions (OH^-). One of the reactions that occurs, as a result, is shown in equation (13).

$$ZSO_4 + 2NaOH \rightarrow Z(OH)_2 + Na_2SO_4 \qquad (13)$$

The waste from the regenerations is disposed of, and the units are put back into service.

Reverse Osmosis

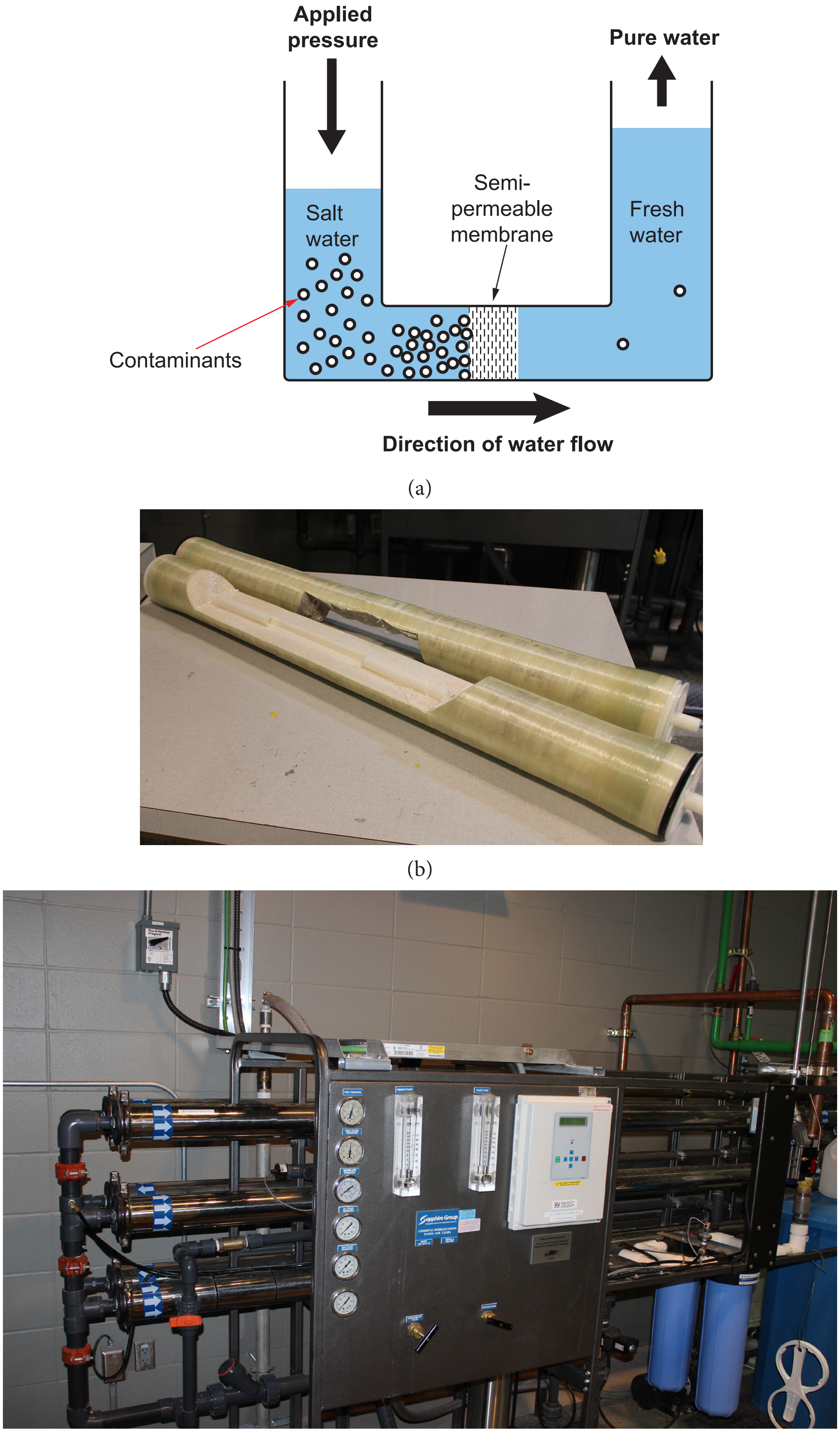
Reverse osmosis (RO) is based on membrane technology, and is not strictly a filtering process. While some material can pass freely through a membrane, others cannot. RO can be effective at removing up to 99% of dissolved solids, organic matter, and colloidal matter. It is commonly used to desalinate sea water. Sea water has a total dissolved solids of about 38 000 mg/L. Therefore, sea water must be treated before being used in a boiler.

In regular osmosis, a membrane separates two fluids: one has impurities in solution and the other does not. The clean fluid will naturally tend to migrate to the side of the membrane with the impure solution.

In reverse osmosis, a pressure is applied to the side with the impurities. The membrane allows water molecules to pass through, but not the impurities (NaCl in the case of sea water). This creates pure water, while concentrating the impurities. Figure 16(a) shows the action behind reverse osmosis.

Figure 16(b) shows cutaways of two membrane cartridges that have been removed from the small reverse osmosis unit shown in Figure 16(c).

Figure 16 – Reverse Osmosis Theory



(a)

(b)

(c)

OBJECTIVE 5

Describe the theory, process, and equipment used in deaeration.

DEAERATION

Dissolved gases, such as oxygen and carbon dioxide, have lower solubility in water as the water temperature rises. When feedwater contains dissolved gases, they come out of solution at the high temperature found in boilers, and cause corrosion. To prevent this, most boiler feedwater systems use deaerators.

The deaerator applies a pressure to the water, and heats it to just below the saturation temperature for that pressure. This frees the dissolved gases from the water, which are then vented from the deaerator. This process is assisted by scrubbing the water with a flow of steam to help sweep away released gases.

Important operating parameters to consider for efficient deaerator operation include:

- **Temperature**: an increase in temperature reduces the solubility of dissolved gases.
- **Turbulence**: steam flow ensures efficient mixing in support of gas scrubbing.
- **Surface Area**: the use of trays increases the surface area of the water which improves the degassing efficiency.
- **Time**: a deaerator's efficiency is a function of the residence time.

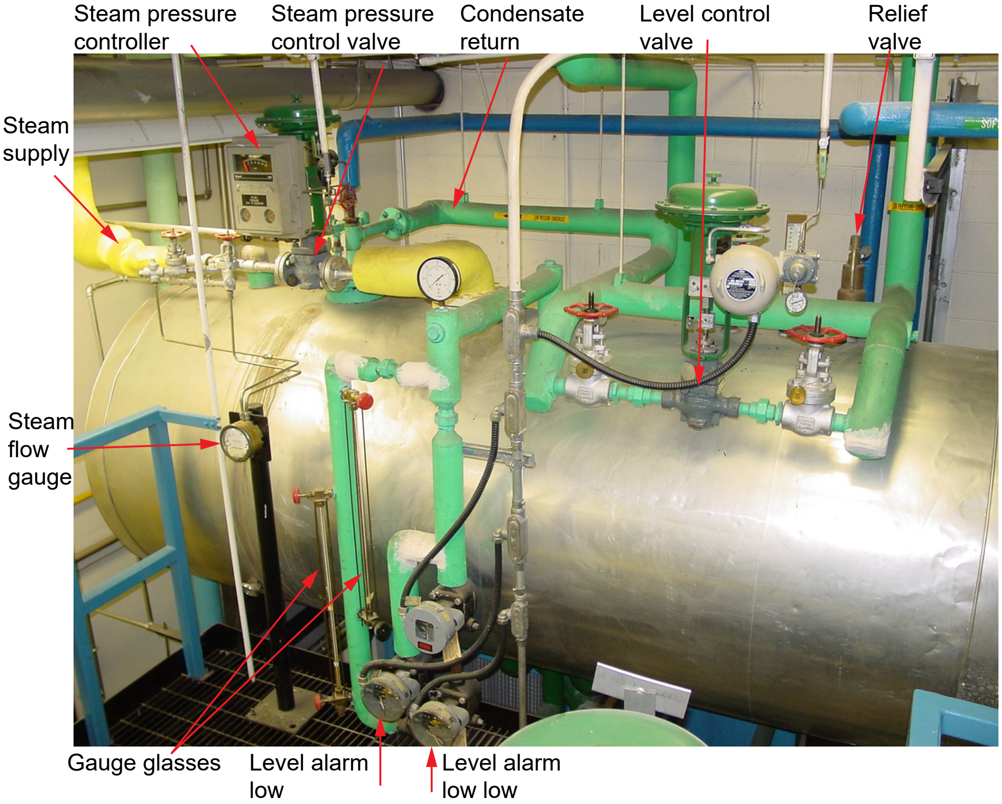
There are two basic deaerator configurations: the spray type and the tray type. Some deaerators combine both principles. The basic differences include:

1. **Tray Type**: the inlet water is directed into a steam chamber. The water heats up in the chamber to within a few degrees of saturated steam temperature. Then, the water cascades down several trays. This increases the surface area of the water, and promotes greater water-steam contact.

2. **Spray Type**: the inlet water is directed into a similar steam chamber as the tray type. However, it is broken up into small particles with spray nozzles, to promote water-steam contact.

Figure 17 shows a photo of a typical spray-type deaerator unit. Make-up water and condensate enter at the top of the unit, and are sprayed into the steam. This quickly heats the water and maximizes the amount of dissolved gases removed from the water. The water passes through a scrubber. The dissolved gases and steam rise upwards through a condenser section. Here, the steam condenses and falls back into the deaerator, and the oxygen and carbon dioxide are vented. The degassed water is stored in the deaerator, and is withdrawn continuously as needed by the boiler feedwater pump.

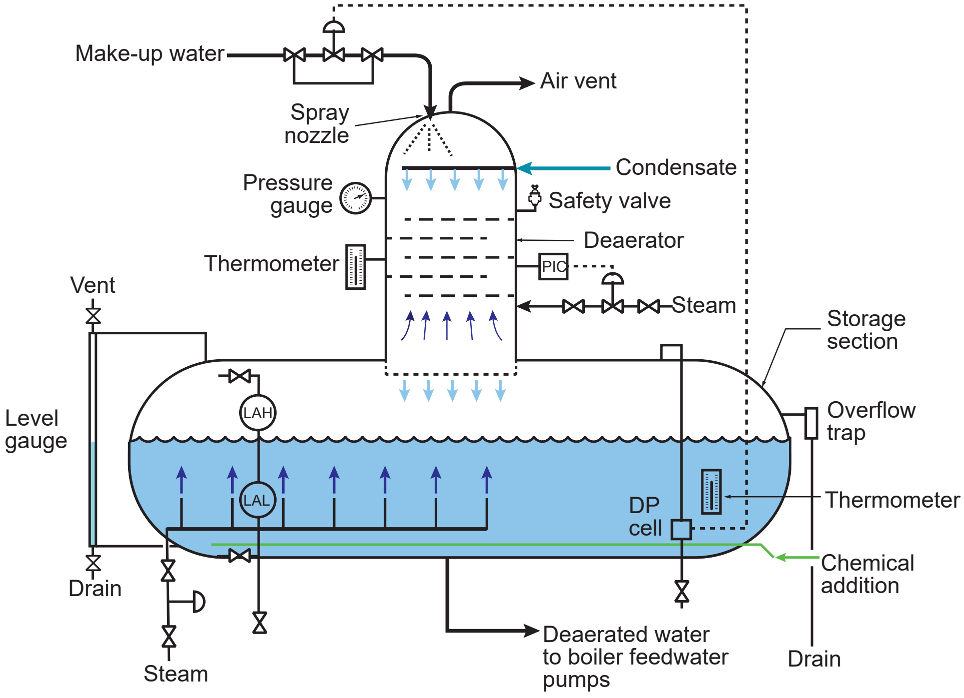
Figure 17 – Spray-Type Deaerator



Figures 17 and 18 show some of the control mechanisms in place on a deaerator. As prescribed by boiler codes, there is a safety valve in place. Other controlled parameters include:

- **Pressure:** controlled by regulating steam flow.
- **Level:** controlled by regulating water flow with an overflow valve, if needed. There are also low-, low-low-, and high-water alarms.

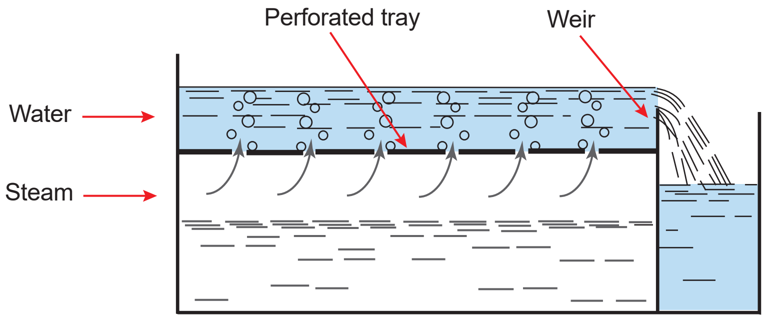
Figure 18 – Spray-Type Deaerator Control Mechanisms



In a tray-type deaerator, the overall process is similar to the spray type. However, instead of passing through spray nozzles, the water flow is broken up by trickling down over a series of trays. The entering steam scrubs the water in the lower trays, and heats the water in the upper tray section. The released gases and remaining steam pass to the internal vent condenser, where most of the steam is condensed and the gases are vented to atmosphere.

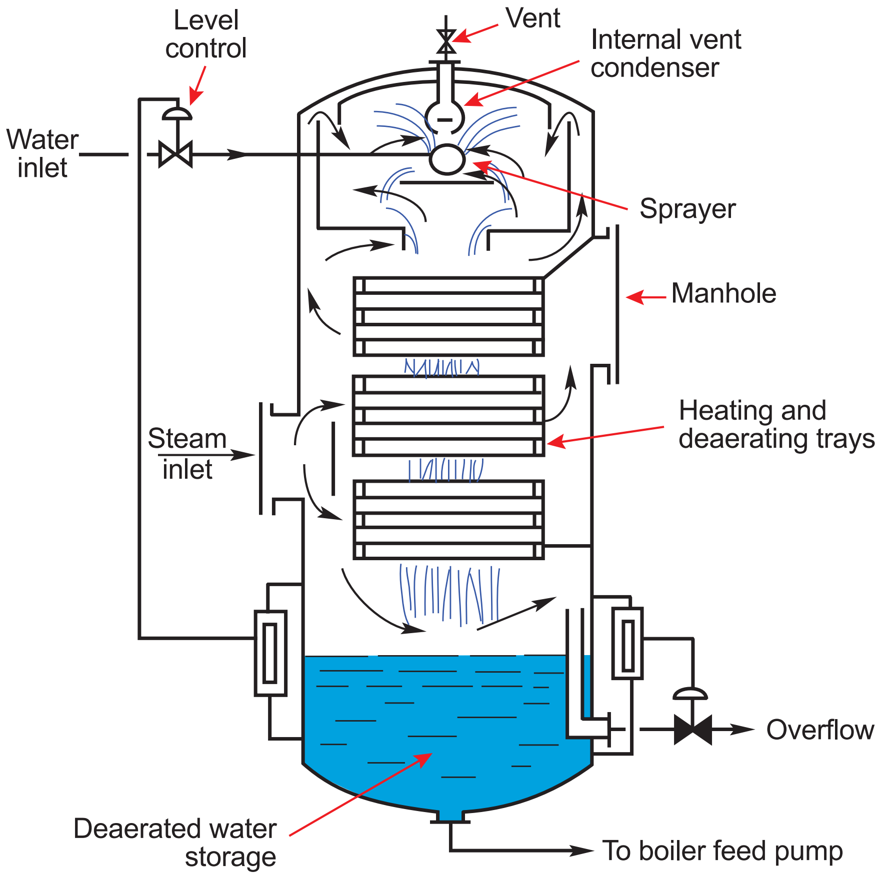
In a bubbling tray deaerator, as shown in Figure 19, steam is forced up through perforated panels as the water flows along the top surface of the panel. The steam bubbles up through the water, causing agitation and intimate contact between the steam and water, thus affecting deaeration. There may be several trays in a stack. The steam rises up through each tray, as the water descends.

Figure 19 – Bubbling Tray-Type Deaerator



Some deaerators combine the spray and tray principles. First, the water is sprayed into the upper heating section of the deaerator. Then, it trickles over a series of steam-swept trays. A combination deaerator is shown in Figure 20.

Figure 20 – Combination Spray and Tray Type Deaerator



In this deaerator, the released gases and remaining steam pass through the incoming water spray on their way to the vent opening. This causes most of the steam that is being carried with the gases to condense. This section of the deaerator is called the internal vent condenser. When the vent condenser is mounted outside the deaerator vessel, it is called an external vent condenser.

CHAPTER SUMMARY

This chapter showed that water can contain a number of impurities, such as solids (both suspended and dissolved), oxygen, and corrosive materials. In certain concentrations, each one can have a detrimental effect on the boiler, and other equipment that the water comes in contact with.

Some of the equipment and processes used included:

- Clarifiers
- Filters
- Lime-soda softeners
- Ion-exchangers
- Demineralizers
- Reverse osmosis units
- Deaerators

The focus was on reducing or removing as many impurities as possible, prior to them reaching the boiler. This external treatment, however, is not perfect. Experienced operators recognize that treatment of the boiler system waters is also required.

CHAPTER 2

Internal Boiler Water Treatment

LEARNING OUTCOME

When you complete this chapter you should be able to:

Describe the general principles, methods, and equipment used for internal boiler water treatment.

LEARNING OBJECTIVES

Here is what you should be able to do when you complete each objective:

1. *Describe the types of problems, and associated treatments, related to internal boiler water contamination.*
2. *Describe internal boiler feedwater chemical feed systems.*
3. *Describe standard boiler water testing.*

CHAPTER INTRODUCTION

External feedwater treatment adjusts raw water to acceptable boiler feedwater quality. However, even after treating the source water, boiler feedwater still contains impurities that could negatively affect boiler operation, and lead to potentially catastrophic equipment failure.

Internal boiler water treatment, usually in the form of chemical addition, is necessary to minimize potential problems. It is critical for energy plant operators to monitor impurities, measure impurity concentrations in the plant system, and adjust water chemistry to within reasonable limits.

Plant operators play a key role in managing water treatment programs. These treatments minimize issues of scale and corrosion, and maximize plant longevity and safety.

For success while studying this chapter, it is necessary to have a good understanding of external feedwater treatment.

OBJECTIVE 1

Describe the types of problems, and associated treatments, related to internal boiler water contamination.

INTERNAL TREATMENT

External treatment of water removes most impurities from boiler feedwater, but not all of them. Even the small amounts that are left are likely to cause boiler failure if left untreated. This makes internal treatment of the water essential.

Internal feedwater treatment involves adding chemicals to the water after it has entered the boiler. This further softens, deaerates, and conditions the water. For most low-capacity, low-pressure heating boilers, internal treatment is the only method used to prevent the formation of scale, corrosion, and sludge.

When low-pressure steam heating boilers are used mainly to generate steam for plant or building heating, practically all the steam condensate is returned from the heating system to the boiler. Very little additional water (make-up) is required after the initial filling of the boiler. The internal water treatment for these boilers is usually quite simple. As the amount of make-up water needed increases, the required internal water treatment becomes more extensive.

Low-pressure hot water boilers are used in closed loop heating systems. The make-up water requirements are usually very low. Internal treatment can focus on pH control and corrosion prevention.

High-pressure boilers are the most affected by impurities. These boilers have much more stringent external and internal water treatment requirements. They also require stricter monitoring of chemical and impurity levels.

The main purposes of internal water treatment programs are to:

- Limit scale formation by precipitating feedwater hardness and keeping it in suspension so that it can be blown off.
- Ensure that suspended solids in the boiler do not adhere to the boiler metal.
- Control the concentration of dissolved and suspended solids in the boiler water without causing **foaming.**
- Eliminate oxygen from the boiler water.
- Provide the right level of alkalinity to prevent boiler corrosion.

Acidity or pH

The **pH** value is a number between 0 and 14. It indicates the degree of acidity or alkalinity of water. A pH of 7 is neutral. Less than 7 is acidic. Higher than 7 is basic (or alkaline). When the water is acidic or excessively basic, more boiler corrosion occurs. A pH of 8.5 or lower, or 11 and higher, can produce significant corrosion. When the pH is too high, foaming will also occur. To limit corrosion, boilers are typically kept at a pH of about 9.5 to 10.5.

A sodium hydroxide (NaOH) solution is often used to raise pH to the required level within the boiler. In some cases, phosphate compounds may also be used to increase the pH level. The solution is fed either directly to the boiler drum, or to the feedwater before it enters the drum.

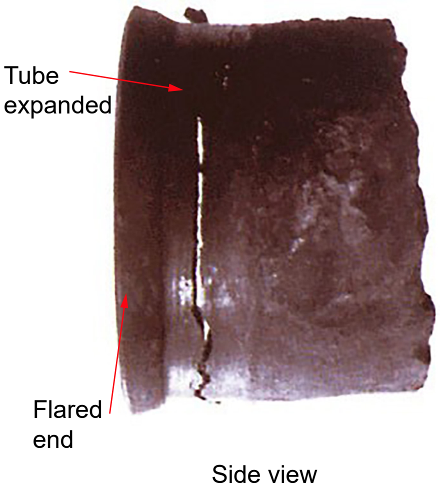
Caustic Embrittlement and Gouging

Caustic embrittlement, also known as **caustic cracking**, occurs when metal under stress is attacked by a concentrated caustic solution. Sodium hydroxide (NaOH), also called caustic soda, is added to boiler water to control pH levels. Some areas can develop a high concentration of caustic either as a result of **steam blanketing** (which allows salts to concentrate on boiler metal surfaces), or by localized boiling beneath porous deposits on tube surfaces.

Caustic embrittlement creates a corrosion pattern that runs around the circumference of the tube, as opposed to other types of corrosion which run longitudinally. Figure 1 shows an example of caustic embrittlement on a tube.

This is of particular concern when it comes to older boilers that have many areas of high stress, such as riveted seams. Boiler tubes usually fail from caustic embrittlement at points where the tubes are rolled into sheets, drums, or headers. The concentrated caustic can cause long cracks to appear. Adding sodium nitrate, **lignins**, and **tannins** has been found effective in preventing caustic embrittlement. However, the most effective way of preventing caustic embrittlement is to limit the boiler water NaOH concentration to the minimum required to achieve target pH and alkalinity.

Figure 1 – Boiler Tube Damaged by Caustic Embrittlement



Another form of caustic corrosion is called **caustic gouging**. This too is a results of a concentration of sodium hydroxide. In areas of high heat transfer, where a deposit of material forms, the sodium hydroxide can concentrate under the deposit to levels of up to 10 000 ppm.

The steel in a boiler naturally creates a thin layer of **magnetite** (Fe_3O_4) on its surface. This protects the steel from further corrosion. A caustic buildup will react with the magnetite, and strip it off the wall. This continues as new magnetite forms, and is then stripped by the sodium hydroxide. The result is that the affected metal becomes progressively thinner. If unchecked, it leads to eventual failure of the tube.

To prevent caustic gouging, the most effective method is to maintain clean boiler metal surfaces (no deposits), and monitor for the presence of excess sodium hydroxide. Again, limit the NaOH concentration in the boiler water to the minimum necessary to maintain target pH and alkalinity.

Foaming, Carryover, Priming

A high concentration of dissolved and suspended solids in boiler water will tend to cause foaming within the boiler. Organic material is often responsible for this. Not only does foaming make it difficult to determine the water level in a boiler, it also allows liquid water to lift over into the steam line (known as carryover). Priming is often referred to as carryover that contains large volumes of water. In some cases, carryover occurs due to a mechanical problem, but foaming is more of a chemical problem.

Foaming is effectively controlled with the use of continuous surface blowdown (near the liquid water surface in the steam drum). As liquid water turns to steam, many of the dissolved solids remain behind in solution. As a result, the liquid water contains higher and higher concentrations of those impurities. Blowdown removes these impurities. In some cases, anti-foaming agents (chemicals) can also be added.

Oxygen Corrosion

Dissolved oxygen causes pitting in the boiler and condensate lines. Figure 3 shows a condensate line that has suffered pitting. This sort of corrosion is particularly worrisome. It is usually highly localized, and can be difficult to spot (although not in Figure 2).

Figure 2 – Pitting Corrosion in Condensate Lines

As water temperature increases, the solubility of oxygen decreases, which results in its release. A deaerator removes dissolved oxygen by raising the temperature of water and venting off the oxygen. Deaerators remove most oxygen, but about 5 to 10 parts per billion remain. To combat the corrosion that the remaining oxygen can cause, scavenger chemicals are usually added to the boiler feedwater line, or to the storage space in the deaerator. These chemicals are highly effective at finding oxygen and reacting with it.

Oxygen scavengers combine with oxygen so that it is no longer available to react with boiler metal. Two chemicals commonly used for this purpose are sodium sulfite (Na_2SO_3) and hydrazine (N_2H_4). Hydrazine has been designated as a toxic substance, and its use is decreasing. Sodium sulfite is commonly used for boilers that operate below 5 000 kPa. It reacts with oxygen to form sodium sulfate (Na_2SO_4) according to equation (1):

$$2Na_2SO_3 + O_2 \rightarrow 2Na_2SO_4 \qquad (1)$$

One disadvantage of sulfite is that it increases the dissolved solids concentration in the boiler. This can lead to foaming and other problems. At high temperatures (which is typical for high-pressure boilers), the sodium sulfate (Na_2SO_4) formed in reaction (1) can break down and form weak solutions of sulfuric acid, which increases the chance of corrosion.

To avoid these two problems in high-pressure boilers, hydrazine (N_2H_4) may be used instead of sodium sulfite. When reacting with oxygen, hydrazine forms inert nitrogen and water according to equation (2):

$$N_2H_4 + O_2 \rightarrow N_2 + 2H_2O \qquad (2)$$

However, hydrazine causes cancer. It must be handled very carefully according to its SDS (Safety Data Sheet). The SDS for this product suggests a self-contained breathing apparatus, as well as, goggles, full-face shield, impervious gloves, apron, and boots.

These factors led to the introduction of alternative oxygen scavengers, including diethylhydroxylamine (**DEHA**). DEHA offers the advantages of very low toxicity, and the high volatility of a **neutralizing amine**. Like hydrazine, DEHA also promotes the formation of a passive magnetite film on low carbon steel surfaces, so it minimizes corrosion in the system.

The overall reaction of DEHA with oxygen is shown in equation (3):

$$4(C_2H_5)_2NOH + 9O_2 \rightarrow 8CH_3COOH + 2N_2 + 6H_2O \qquad (3)$$

DEHA also has the ability to act as a passivating agent in the return line system, after it has passed out of the boiler with the steam.

Preventing corrosion caused by oxygen and/or carbon dioxide in the return and steam lines is more challenging. Some carbon dioxide may form from decomposition of bicarbonates, or air may leak in through return lines. Any added chemicals must be able to get to the return condensate lines to prevent this form of corrosion. The most common chemicals used are **amines.**

There are two main types of amines:

- Neutralizing
- Filming

Neutralizing amines are volatile. They flash off and travel with the steam to the rest of the system. Therefore, they can be fed directly to the boiler. However, it is more economical to feed neutralizing amines directly to the steam header.

Neutralizing amines are alkaline. They will neutralize any acids formed in the condensate. This reduces any effects carbon dioxide might otherwise cause. Only a few ppm of amine are necessary for it to be effective.

Filming amines are not as soluble, and are usually injected into the steam header. When steam condenses, these chemicals will create a thin coat over the piping surfaces, protecting the surfaces from acidity and corrosion.

Molybdate is another chemical used to protect the boiler from corrosion. It is commonly used in hot water boilers, low-pressure steam boilers, and closed-loop cooling systems.

The product of reaction between molybdate and iron is:

$$2Fe^{3+} + 3MoO_4^{2-} \rightarrow Fe_2(MoO_4)_3 \qquad (4)$$

This reaction precipitates an inert passivating barrier layer (ferric molybdate) on the metal surface.

The concentration of molybdate in the boiler is generally maintained within the range of 75 to 125 ppm. This is controlled through regular blowdowns and regular additions.

Scale Formation

As discussed in the previous chapter, dissolved solids in a boiler can react chemically with other ions, and precipitate on heating surfaces.

In a boiler, scale has both economic and operational effects. This is caused by the reduction in heat transfer at the surface, which then requires additional fuel to maintain the same heat output. Scale adds significantly to fuel costs. The estimated increase ranges from 9% for 0.1 cm of scale, to 70% for 1 cm of scale.

In addition to loss of heat transfer, scaling can lead to physical damage, as well. Scale deposition results in restricted water flow, local hot spots, and ultimately tube rupture. Figure 3 shows an extreme case of scaling inside a tube. This level of scale severely limits water flow, and leads to the overheating of metal surfaces.

Figure 3 – Solid Scale Inside a Tube

Figure 4 shows three examples of what can happen when a boiler tube has scale formation that results in local overheating. The tube overheats, bulges, and eventually ruptures.

Figure 4 – Tubes Damaged from Overheating

To prevent scale formation due to deposition of calcium and magnesium compounds, chemicals are added that will precipitate the impurities in a different form. Rather than form hard scale on the boiler surfaces, they will form soft scale that is much less likely to adhere to heat transfer surfaces. These solids, along with water, form a sludge and are removed quite effectively using intermittent bottom blowdown.

The most common chemical added to a boiler for this sort of scale prevention is sodium phosphate (Na_3PO_4). In boilers with water having a moderate alkalinity (pH 11 to 12), calcium phosphate ($Ca_3(PO_4)_2$) is precipitated. A phosphate residual of 20 to 40 ppm should be maintained for most boiler systems.

Magnesium is precipitated from the boiler water as well.

Other chemicals used include sodium carbonate (Na_2CO_3), although this can increase carbon dioxide in the condensate return lines, sodium hydroxide (NaOH) and sodium aluminate ($NaAlO_2$).

Scale can also form due to iron oxides, copper, or silica (SiO_2).

Chelants are commonly used in boiler water treatment programs to trap metallic ions, and make scales more soluble. In solution, they will trap and hold calcium, magnesium, and iron ions. However, compared to phosphate systems, they are more expensive, and more complicated to use.

Chelants are also effective at removing hard scale that may have already formed. However, this must be done carefully. Chelants can cause large clumps of hard scale to be released, which can disrupt the stream flow, or cause deposits in areas of lower circulation. These accumulations can plug headers or redeposit in critical circulation areas, such as furnace wall tubes.

If not part of a comprehensive water treatment program, chelants by themselves may attack bare steel surfaces after scale has been removed. A common chelant used is **EDTA** (ethylenediaminetetraacetic acid).

Sludge Deposits

The sludge produced by the precipitation of soft scale in the boiler must be conditioned so that it will stay fluid and well dispersed, until it is removed through blowoff. Otherwise, sludge will likely deposit on hot surfaces. The chemicals added for this purpose are usually organic compounds, such as starch, tannin, lignin, and **alginates**. These organics coat the scale precipitates, and prevent them from adhering to the boiler internals. Sometimes polymers are also used.

OBJECTIVE 2

Describe internal boiler feedwater chemical feed systems.

INTERNAL TREATMENT FEED SYSTEMS

Well-designed and maintained chemical feed systems are crucial for safe and efficient boiler operation. An inappropriately designed or inefficiently run feed systems can result in:

- High corrosion costs and damage to equipment.
- Extra chemical costs due to waste or overfeeding.
- Poor steam quality.

The method used to supply the necessary chemicals to the boiler water is usually a small positive-displacement motor-driven metering pump. The pump may be connected to inject the chemicals directly to the boiler drum, the feedwater line, or the deaerator. Chemical feed pumps should be checked regularly, and maintained according to the manufacturer recommendations.

The chemical feed line to the boiler must be equipped with a shut-off valve next to the boiler. There must also be a check valve between the chemical feed pump discharge isolation valve and the shut-off valve at the boiler. Unless the chemical feed pump has an internal relief mechanism, a relief valve must be installed on the discharge of the pump, before the pump discharge isolation valve. This is because chemical feed pumps are positive displacement types. They can over-pressurize piping and fittings if a valve in the discharge line is shut while the pump is running.

Chemical feed pumps are high-pressure, low-capacity types with adjustable flow rates. To adjust the flow, adjust the length of the pump stroke, or the drive motor speed.

Figure 5 shows a diaphragm chemical pump that has an adjustable flow rate. A knob with a calibrated dial is used to adjust the pump stroke. For accurate control of the chemical feed, the calibration on the dial can be cross-referenced to the manufacturer flow rates.

Figure 5 – Adjustable Flow Chemical Pump

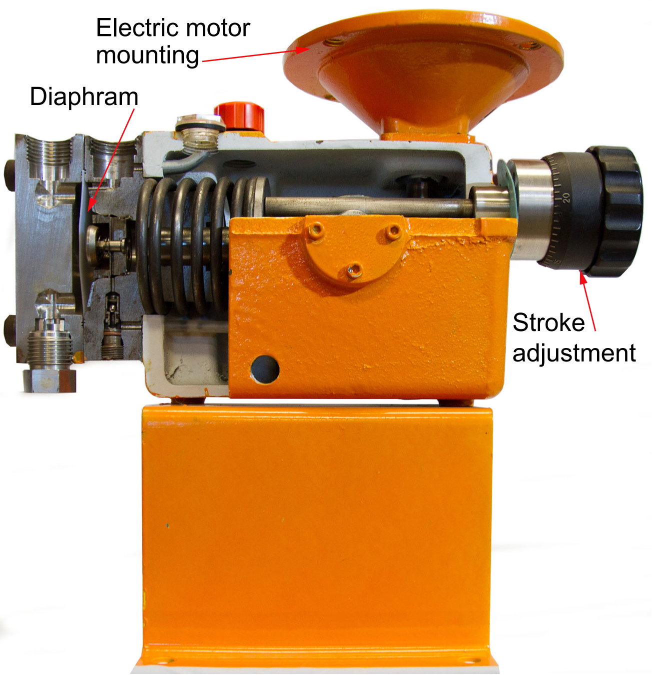
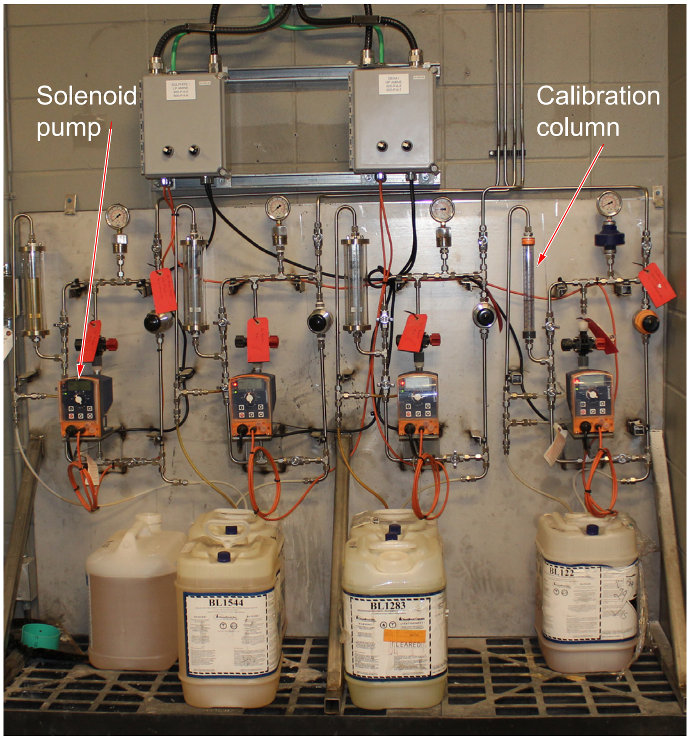
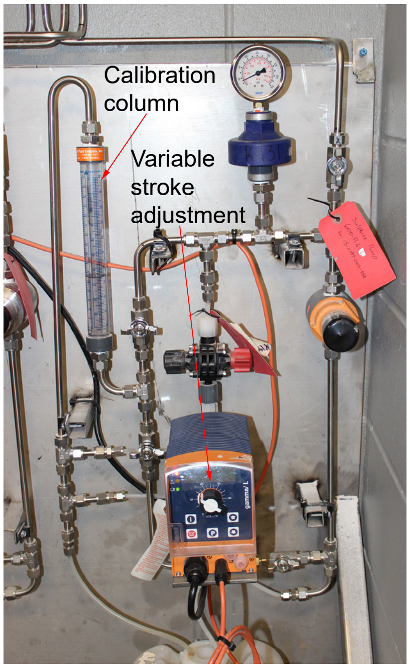


Figure 6(a) shows a complete chemical injection system. It has four solenoid-type pumps supplying different chemicals to different parts of the plant. Figure 6(b) is a close up that shows the flow measurement and stroke adjustment of one of the pumps. These pumps draw liquids from the containers directly below them. The variable pump stroke is adjusted based on the results of water tests. Some pumps are enabled by boiler feedwater flow. They cannot operate if there is no boiler feedwater flow.

Figure 6 – Power Plant Chemical Feed Pump Arrangement



(a)



(b)

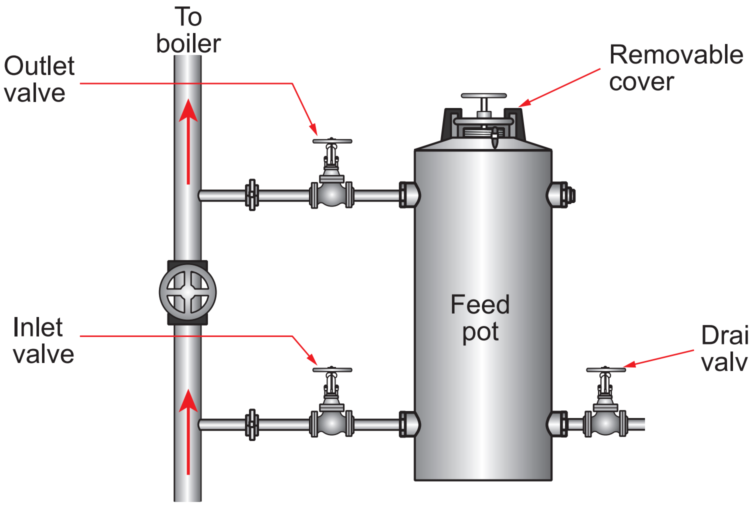
Chemical Feeders

Chemical feeders supply chemicals to the return line of a hot water circulating system, or directly into a boiler, without using feed pumps.

Feeders used for closed water heating systems, with low make-up water requirements, are quite simple. After the initial treatment of water, only small quantities of chemicals have to be periodically fed into the system.

The bypass feeder ("pot" or "shot" feeder) shown in Figure 7 feeds chemicals, supplied in liquid, briquette, or ball form into the feedwater or circulating line.

Figure 7 – Closed Type Bypass Feeder



To add chemicals to the system, follow the steps below.

CAUTION

The water in the feeder is hot and under pressure. Ensure proper PPE is worn to protect from burns, chemical exposure, and splashes.

1. Close the inlet valve.
2. Close the outlet valve.
3. Open the drain valve.
4. Remove the feed pot cover. The water inside the feeder will drain from the drain valve.
5. Close the drain.
6. Measure and add the chemicals to the feed pot, through the open cover.
7. Carefully fill the feed pot with system water, by cracking open the inlet valve. Close the inlet valve when all air is vented from the feed pot.
8. Ensure the cover gasket is properly aligned and in good condition. Replace the feed pot cover, and tighten it in place.
9. Open the inlet valve. Check to ensure the cover does not leak.
10. Open the outlet valve.

Figure 8 shows a chemical shot feeder installation. This feeder is equipped with a pressure gauge, so that the operator can see if the feeder is in service. As well, it has a vent to assist with removing the air from the feeder before placing it on-line.

Figure 8 – Chemical Shot Feeder Installed

OBJECTIVE 3

Describe standard boiler water testing.

The required water treatment equipment is determined by both the needs of the equipment in the plant, and the characteristics of the source water. To optimize the selection and usage of this equipment, it is important to know the local water chemistry. This will identify the conditions that need treatment, and help to select and size the equipment. This information is available in a water analysis for the raw water supply.

Testing the water treatment equipment and chemical effectiveness is an important part of the boiler operation process. In order to ensure proper system chemistry, and to verify that the water treatment equipment is doing its part, daily testing and recording in a chemical log book is recommended.

The most important part of any treatment program is to make the dosing adjustments necessary for maintaining correct boiler water chemistry. Merely recording a number that is out of the desired range does nothing to protect the equipment. Power Engineers work with chemical suppliers to develop appropriate control ranges for plant water treatment systems, based on the raw water quality, the amount of makeup water, the external treatment equipment, and the size and type of boilers. The onus is on the operator to adjust chemical feed, blowoff, and blowdown as required to stay within the control ranges.

TESTING METHODS

Safety Gear

To determine the nature and amount of the impurities present in the boiler water, or feedwater, it is necessary to obtain samples and subject them to various tests.

When testing boiler water, always wear eye protection and protective coveralls. These will guard against splashes and burns. It is also a good idea to use heat resistant gloves.

When working with any acids or bases, always wear a splash apron and acid/base resistant gloves. Use a face shield and splash goggles instead of just safety glasses. It is also important to have respiratory protection, with cartridges specific to the material group being handled.

Always conduct tests in open spaces and, if possible, beneath a fume hood. Follow the plant's testing and safety procedures. Always read the SDS for any unfamiliar chemicals, and follow their safety guidelines. By law, an SDS for each controlled chemical must be available to all employees in an accessible location.

Sampling Methods

A standard sampling process is an important first step for an effective water management program. The sample should be representative of the boiler water. Make sure that stagnant water is not part of the sample. Run water from the sampling line long enough for the stagnant water to clear. Never take a sample from a sight glass.

Before taking a sample, clean the sampling containers to ensure accurate results. Rinse out the containers with water from the sampling line before taking the sample to be tested. This normally requires a triple rinse of the sampling container with the sample water.

The sample should be tested as soon as possible. Be careful because it could be hot.

Depending on the test and the test equipment used, samples may need to be cooled using sample coolers. Care must be taken so that dissolved and solid particles do not settle out, and no flash-off occurs due to pressure effects. Seal the sample to keep air out. Figure 9 shows a typical sample cooler for a boiler that allows samples to be cooled without worry of flash-off.

Figure 9 – Boiler Sample Cooler

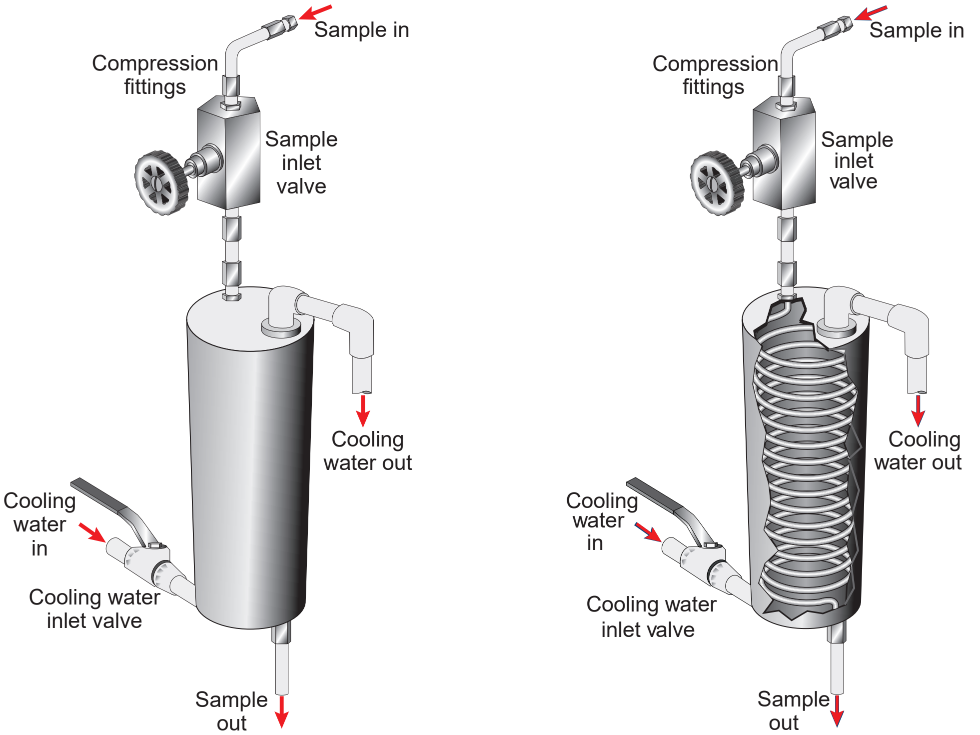
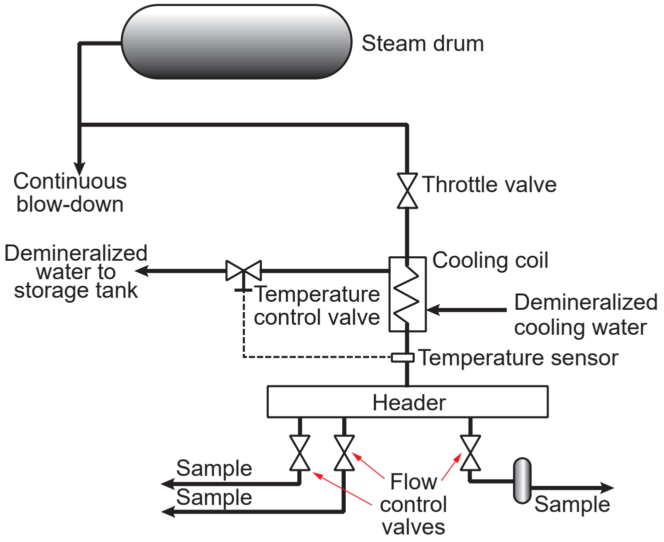


Figure 10 shows an automatic sampling arrangement. The sample line is connected to the continuous blowdown line; the sample water is obtained from this point. The sample cooler reduces the temperature of the sample to a standard temperature (often 24°C). It then flows to a sample header. Individual sample lines run from the header to automatic analyzers, which continuously test for different characteristics, such as dissolved solids, excess sulfite, or excess phosphate.

Figure 10 – Automatic Sampling System



Testing Area

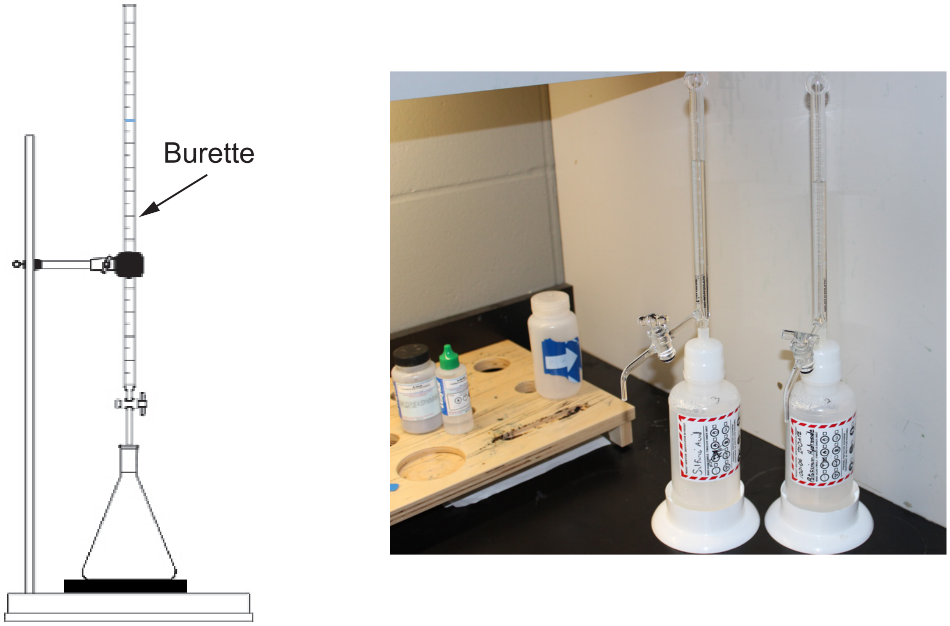
An open area should be used for testing, so fumes do not accumulate. Preferably, the test area should be equipped with a fume hood. There should also be a supply of hot and cold potable water and a power outlet for test meters. The potable water is used to rinse equipment after use. Distilled water must be available for final rinsing of any equipment, before and after use, to maximize the accuracy of results. The test area should also have good lighting to help with colour identification during titrations.

Titration

Many of the tests performed in a power plant use a method of analysis called **titration**. This method allows precise determination of a reaction **endpoint**, and thus the amount of reactant in the sample. Figure 11 shows typical laboratory equipment used for titration.

The main piece of equipment used to deliver titration reagents to samples is a **burette**, which comes in both manual and autofill types. The autofill example shown fills the burette by squeezing a solution bottle until the burette is filled beyond the zero line. The burette overflow then drains back into the solution bottle until the zero volume line is accurately and repeatedly reached. Autofill burettes are most often used in power plants.

Figure 11 – Titration Equipment



TESTS

In many plants, sampling and testing are still done manually. Several of the more common tests include:

- Hardness
- pH
- Conductivity (dissolved solids)
- Molybdate
- P and M Alkalinity
- Phosphate
- Sodium sulfite

On Track

The results of water tests are influenced by poor lab technique, and deviation from test procedures. Test results can therefore vary widely. Always follow the procedures prescribed by the water treatment professional employed by the plant. If unusual test results are obtained, repeat the test to ensure the validity of the readings.

Hardness Test

Hardness is a measure of the amount of calcium (Ca) and magnesium (Mg) ions present in water. The more ions present, the higher the hardness value. This is an indication of how much scale would form on heating surfaces. Hardness tests may be performed on raw water entering a plant site, and on the outlet of water softeners.

To conduct a hardness test, take a water sample, and then titrate to determine the total hardness. Total hardness is expressed as ppm of equivalent $CaCO_3$.

Hardness Test Procedures (Titration)

1. The expected hardness determines the sample size used in this test (20 ml, 50 ml, or 100 ml). For example, well water will have a very high hardness, so a small sample size will be analyzed. Water from the outlet of a softener will have a very low hardness, so a larger sample will be analyzed for greater accuracy.
2. Add 1 ml of calcium magnesium hardness buffer, and 1 spoonful of hardness indicator. Stir continuously. The indicator spoon is supplied with the container.

a) If the solution turns blue, no hardness is present.

b) If the solution turns red, hardness is present, and the sample will require further testing titration.

3. **Titrate** with sodium EDTA solution, to a single drop endpoint.
4. Hardness in ppm $CaCO_3$ (equivalent) equals volume added (ml) times the multiplication factor supplied by the water treatment company.

Operator Response to Hardness Test

The location of the sample point, and the level of hardness obtained by the test procedure, will determine the action required. A water sample taken from an ion-exchange softener should show zero hardness. If any amount of hardness shows, the softener requires regeneration.

Hardness tests are not conducted on boiler water. However, if the boiler phosphate residual is low, the load on the boiler has not changed, and the chemical feed rate has been stable, low phosphate may indicate hard water is entering the boiler. In this situation, hardness tests can be performed on various condensate returns to pinpoint the source of the contamination.

pH Test

The pH level is crucial to safe boiler operation. A weak basic, or acidic environment ($\text{pH} < 8.5$), is likely to increase corrosion. One that is strongly basic ($\text{pH} > 13$) can also cause problems. For most boilers, a pH of 9.5 to 10.5 is desired.

Commonly, an electronic pH meter is used for measurements, although colour comparisons and titrations can also be used. Figure 12 shows a typical pH meter. Insert the probe into the sample, and read the pH level directly from the meter. The meter automatically measures the temperature of the sample, and adjusts the reading accordingly.

Probes need to be recalibrated from time to time, using calibration solutions. The blue solution being tested in Figure 12 is used to calibrate the meter to a pH of 12.

Figure 12 – Electronic pH Meter

Figure 13 shows a typical colour comparison test. The test strip is immersed in the water and changes colour, according to its pH. Shortly after changing colour, the strip is compared to a chart to determine the pH. The strip shown covers a very narrow pH range.

Figure 13 – pH Colour Test

Operator Response to pH Test

The pH tests are commonly performed on condensate and boiler water.

Excessively high condensate pH indicates an overfeed of costly neutralizing amine. Reduce the amount of amine feed used.

Excessively low condensate pH indicates an underfeed of neutralizing amine. Increase the amount of amine feed.

Excessively high boiler water pH increases the potential for caustic embrittlement, cracking, and gouging. Reduce the feed of caustic soda (NaOH) to the boiler. If necessary, increase the rate of continuous blowdown, especially if the total alkalinity is high.

Excessively low boiler water pH increases the likelihood of acidic corrosion. It also inhibits the ability of phosphate compounds to combine with scale-forming compounds. Increase the feed of NaOH to the boiler. If the total alkalinity is low, reduce the amount of continuous blowdown.

For boiler water, it is more important to know the hydroxyl (OH^-) alkalinity than to determine pH. Hydroxyl alkalinity is determined using the P and M alkalinity test discussed later in this objective.

Dissolved Solids Test

Dissolved solids can result in scale and corrosion. Total dissolved solids (TDS) content measures all the salts in solution.

The dissolved solids can be determined using a conductivity meter. As the concentration of dissolved solids increases, so too does the conductivity. The two are directly related. This means that the concentration of dissolved solids can be determined by multiplying the liquid water conductivity by a constant factor.

On Track

Conductivity is usually measured in microsiemens per centimeter (µS/cm) or millisiemens per centimeter (mS/cm). The term “siemens” is occasionally substituted with the term “mhos”. One siemen is equal to one mho, so 1 µS/cm is the same a 1 micromho/cm.

Figure 14 shows a conductivity meter. A manual measurement is being performed. This particular meter can show conductivity in µS (a), or TDS in ppm (b), depending on what is required by the lab.

Pour the water into the sample cup at the top of the meter, or submerge the top part of the meter directly into the water. The meter automatically measures the temperature of the sample, and adjusts the reading accordingly.

Figure 14 – Manual Conductivity Measurement

(a) (b)

Operator Response to Dissolved Solids Test

The measurement of dissolved solids is used to determine the amount the continuous blowdown valve should be open.

Excessively high TDS results in foaming, priming and carryover. If the TDS is high, increase the rate of continuous blowdown.

Excessively low TDS indicates excessive blowdown or blowoff. This wastes water, heat energy, and chemicals. Reduce the amount of blowdown and blowoff.

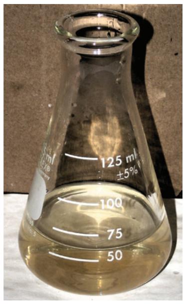
Newer systems incorporate conductivity readings with automatic continuous blowdown control.

Molybdate

Molybdate is a compound of molybdenum. Molybdate salts are often used as corrosion inhibitors in closed loop heating and cooling water systems. When combined with other chemicals, such as azoles and orthophosphates, molybdates are used in low-pressure steam heating boilers. When used in a combined treatment, the required concentration of molybdate can be reduced.

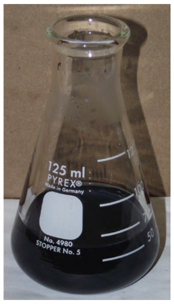
The molybdenum test determines residual molybdate levels to ensure that the treatment program is in place. A drop kit is often used to perform this test. Figure 15 illustrates the process.

Figure 15 – Molybdate Testing



(a)

Initial Sample



(b)

With Mo Indicator Added

(c)

Endpoint with titrant drop bottle

Molybdate Test Procedures

1. Measure and filter a 50 ml sample into a flask. Ensure the sample water is cooled to around 23°C. See Figure 15(a) – Initial Water Sample.

On Track

When measuring the sample in a graduated cylinder, or the level in a burette, read the level at the bottom of the meniscus.

2. Add the correct amount of Mo buffer, and mix.
    a) For cooling water and closed water systems (chilled and hot water), add 1 ml.
    b) For steam systems, add 2 ml.

3. Add heavy metal eliminator (1 scoop).
4. Add Mo indicator (1 scoop). If molybdenum is present, a blue colour will develop. See Figure 15(b) – Water Sample With Mo Indicator Added.
5. While swirling, titrate drop-wise until all the blue colour is eliminated. The endpoint is a pale yellow colour. See Figure 15(c) – Endpoint.
6. Record the number of drops.
7. The number of drops × 5 mg/L Molybdenum as Mo.

Operator Response to Molybdate Test

The feed rate of the molybdate, or combined molybdate compound, is increased or decreased to bring the reading back to the control range recommended by the water treatment company.

Alkalinity

Alkalinity tests are performed on both source water and boiler water. Source water is tested to determine the efficacy of the feedwater treatment program. The boiler water test allows the operator to make the necessary adjustments to ensure that OH^- and total alkalinity are within the prescribed control range.

By definition, alkalinity is a measure of a solution's ability to resist changes in pH. This is due mostly to the presence of weak salt acids (bicarbonates and carbonates) and, in some cases, stronger bases (hydroxides). Three types of alkalinity are normally identified:

1. Carbonate
2. Bicarbonate
3. Hydroxyl (OH^- or caustic)

The two tests most often used to determine the alkalinity of water are:

1. **Phenolphthalein alkalinity** test (to test for hydroxides and carbonates)
2. **Methyl alkalinity** (or total alkalinity) test (to test for hydroxides, carbonates, and bicarbonates).

Hydroxyl (OH^- or caustic alkalinity) may be calculated from these two tests.

Phenolphthalein Alkalinity (P-Alkalinity) Test Procedure

1. Use a graduated cylinder to measure a 50 ml water sample, and place it in a casserole (see Figure 16).

Figure 16 – Graduated Cylinder and Casserole


(a) (b)

2. Add 3 drops of phenolphthalein indicator, and stir. (**Phenolphthalein** is a pH indicator with an endpoint of pH 8.2 to 8.3). If no colour appears, the P-Alkalinity is zero.

Figure 17 – P-Alkalinity Titration


(a) (b) (c)

3. If the sample turns pink (Figure 17(a)), it is titrated with a standard sulfuric acid solution (N/50). The sample is continually stirred while the sulfuric acid is added. The following reactions take place:

$$OH^- + H^+ \rightarrow H_2O \text{ (Hydroxide Alkalinity)}$$

$$CO_3^{2-} + H^+ \rightarrow HCO_3^- \text{ (1/2 Carbonate Alkalinity)}$$

4. Figure 17(b) shows that a full burette of acid (10 ml) was used, without a complete colour change occurring. The burette was refilled, and titration resumed. The colour disappeared at the reading shown in Figure 17(c) (1.1 ml). Therefore, the total acid used was 11.1 ml.

On Track

Do not discard the sample, and do not refill the burette at this point. They will be used for the M-alkalinity test.

5. P-Alkalinity (P) as ppm of $CaCO_3$ = ml of titrant × 20. In this case:

$$11.1 \text{ ml} \times 20 = \mathbf{222 \text{ ppm } CaCO_3 \text{ equivalent.}}$$

P-alkalinity is equal to all of the OH^- alkalinity and ½ of the CO_3^{2-} alkalinity. Therefore:

$$P = OH^- + \tfrac{1}{2} CO_3^{2-} \text{ or } \mathbf{2P = 2OH^- + CO_3^{2-}}$$

Total Alkalinity (M-Alkalinity) Test Procedure

Conduct this test immediately after the P-alkalinity test, using the same sample.

1. Add 4 drops of methyl purple indicator and stir the sample. The sample will turn to a green colour as shown in Figure 18(a). Titrate using N/50 sulfuric acid. The colour will begin to change to purple as shown in Figure 18(b).

Figure 18 – M-Alkalinity

(a) (b)

2. Continue titrating until the colour changes completely to purple as shown in Figure 19(a).
3. M-Alkalinity (M) as ppm of $CaCO_3$ = ml of titrant × 20. In this case:

$$12.0 \text{ ml} \times 20 = \mathbf{240 \text{ ppm } CaCO_3 \text{ equivalent.}}$$

Figure 19 – M – Alkalinity Endpoint

(a) (b)

Determining OH^- (Hydroxyl) Alkalinity

OH^- alkalinity and HCO_3^- alkalinity cannot exist together in solution. They react to form carbonate alkalinity and water ($OH^- + HCO_3^- \rightarrow CO_3^{2-} + H_2O$). Therefore:

- **If OH^- alkalinity is present**, M-alkalinity represents all of the OH^- alkalinity and the CO_3^{2-} alkalinity.
- **If HCO_3^- alkalinity is present**, M-alkalinity represents all of the HCO_3^- alkalinity and the CO_3^{2-} alkalinity.

Most boiler water contains only OH^- and CO_3^{2-} alkalinity. Therefore, **M-alkalinity = $OH^- + CO_3^{2-}$**. Recall that **$P = OH^- + ½CO_3^{2-}$**, and that **$2P = 2OH^- + CO_3^{2-}$**. If M is subtracted from 2P, the result is OH^- alkalinity. This can be proven as follows:

$$\begin{aligned} 2P - M &= 2OH^- + CO_3^{2-} - (OH^- + CO_3^{2-}) \\ &= 2OH^- + CO_3^{2-} - OH^- - CO_3^{2-} \\ &= OH^- \\ \text{Therefore,}\quad 2P - M &= OH^- \text{ alkalinity} \end{aligned}$$

So using the previous example:

$$\begin{aligned} \text{P–alk} &= 222 \text{ ppm as } CaCO_3 \\ \text{M–alk} &= 240 \text{ ppm as } CaCO_3 \\ OH^-\text{–alk} &= 2P - M = 2 \times 222 - 240 = 204 \text{ ppm as } CaCO_3 \text{ (equivalent)} \end{aligned}$$

There are other mathematical relationships between P and M alkalinity that can be used to ascertain the concentration of alkalinity species in boiler water. These are shown in Table 1.

Table 1 – Alkalinity Relationships

Results of P and M Tests	Hydroxyl Alkalinity (OH^-)	Carbonate Alkalinity (CO_3^{2-})	Bicarbonate Alkalinity (HCO_3^-)
P = 0	0	0	M
P = M	M	0	0
P = ½ M	0	M	0
P < ½ M	0	2P	M-2P
P > ½ M	2P – M	2(M – P)	0

These tests are reported as ppm of $CaCO_3$ equivalent. Analysis of the results can be used to determine the predominant species affecting the alkalinity. The correct measures can then be taken to minimize those contaminants. While the total alkalinity must be kept below a maximum level to avoid corrosion, caustic embrittlement, and carryover, a minimum level of OH^- alkalinity is often needed to prevent scaling.

If the majority of the alkalinity is due to hydroxyls, the risk of caustic embrittlement increases. If the bicarbonate concentration is excessive, free corrosive carbon dioxide is released.

In the previous example, it was determined from 2P-M that the OH^- alkalinity was 240 ppm. Referring to Table 1, where P is greater than one half of M, the CO_3^{2-} alkalinity can be determined using 2(M-P):

$$\begin{aligned} CO_3^{2-} &= 2(M - P) \\ &= 2(240 - 222) \\ &= 36 \text{ ppm} \end{aligned}$$

The bicarbonate alkalinity, as expected, is 0 ppm.

The values of P, M, and OH^- alkalinity are recorded on the log sheet, and compared to control range on the log sheet.

Self-Test 1

During a P and M alkalinity test, a 50 ml boiler water sample is titrated with N/50 sulfuric acid. The test yielded the following results:

- P-alkalinity consumed 15 ml of H_2SO_4
- M-alkalinity consumed another 7.5 ml H_2SO_4

The test requires the titrant in ml to be multiplied by 20 to give results in $CaCO_3$ equivalents.

Determine the following:

a) OH^- alkalinity

b) CO_3^{2-} alkalinity

c) HCO_3^- alkalinity

a) 150 ppm (Ans.)
b) 300 ppm (Ans.)
c) 0 ppm (Ans.)

Operator Response to Alkalinity Tests

Excessively high total alkalinity may result in foaming or carryover. If the total alkalinity is excessively high, increase the rate of continuous blowdown. It may be necessary to conduct more frequent or longer bottom blowoffs.

Excessively low total alkalinity indicates excessive continuous blowdown or bottom blowoff. This results in a costly loss of boiler water, chemicals, and heat energy. As well, the overall boiler water chemistry will likely be outside of prescribed limits. Decrease the rate of continuous blowdown and blowoff.

Excessively high OH^- alkalinity may cause caustic gouging, destabilization of protective magnetite layers, or caustic embrittlement. In this situation, it may be necessary to increase the rate of continuous blowdown. However, in a coordinated phosphate treatment program, the OH^- alkalinity will be consumed over time. It may simply be necessary to reduce or eliminate the feed of NaOH to the boiler until the OH^- alkalinity drops.

Excessively low OH^- alkalinity is also a problem. OH^- alkalinity must be present in boiler water because:

1. OH^- ions neutralize acidic conditions that may create waterside corrosion.
2. OH^- ions are important for the precipitation reactions that reduce scale deposition, when a coordinated phosphate water treatment program is used.

In this situation, feed NaOH to the boiler in small amounts.

Sodium Sulfite

The presence of dissolved oxygen in boiler water causes significant corrosion issues. External treatment of water can reduce levels to the range of 10 parts per billion. However, this is inadequate, especially at higher operating pressures.

To eliminate the presence of dissolved oxygen, a residual of excess sodium sulfite may be maintained in the boiler water. The sodium sulfite (Na_2SO_3) combines with dissolved oxygen to form Na_2SO_4. In this combined form, the oxygen cannot contribute to waterside corrosion. Sodium sulfite is usually added to the feedwater system to protect the deaerator, the feedwater lines, and the feedwater pumps, as well as the boiler.

Sulfite Residual Test Procedure

1. Take a representative sample of boiler water. This sample must be protected from atmospheric oxygen, or a false low reading will result. To do this, ensure the sample bottle is filled to the top, and all air is excluded. Then, tightly cap the sample bottle. Keep the bottle shut until the test is conducted.
2. Measure a 50 ml sample of boiler water, and place it in a casserole.
3. Add 4 spoons of acid starch indicator to the sample. Use the small spoon included with the indicator container. See Figure 20(a).
4. Titrate the sample with potassium iodide-iodate solution. See Figure 20(b).

Figure 20 – Sulfite Test

(a) (b)

5. When a permanent blue colour is reached, record the volume of potassium iodide-iodate solution, in ml. See Figure 21(a).
6. Multiply the ml of titrant by 20 to find the ppm of excess sodium sulfite. See Figure 21(b).

Figure 21 – Sulfite Test II

(a) (b)

In the example shown, the volume of titrant used was 1.9 ml. To determine the sulfite residual, the volume of titrant used must be multiplied by 20. Therefore, the sulfite residual is:

$$1.9 \times 20 = 38 \text{ ppm}$$

This value is entered in the water log and compared to the control range.

Operator Response to Residual Sodium Sulfite Test

The setting of the sodium sulfite feed pump is adjusted to provide more or less sulfite, according to the readings. The amount of excess sulfite is usually maintained at about the 20 to 60 ppm range for operating boilers, and up to 80 ppm for boilers in wet layup.

Excessively high sodium sulfite may cause increased sludge and scale formation. In certain circumstances, sodium sulfite can contribute to waterside corrosion. Because sulfite is continuously consumed, high sulfite levels can be addressed by reducing the rate of sulfite addition to the feedwater, until the sulfite concentration stabilizes within the control range.

Excessively low sodium sulfite will result in dissolved oxygen in the boiler water, and pitting corrosion. Excessive pitting will destroy the boiler. If the sulfite residual is low, increase the amount of sulfite fed to the feedwater until the concentration stabilizes within the normal control range.

Phosphate

Sodium phosphate may be added directly into the boiler to prevent scale formation. The phosphate reacts with calcium and magnesium ions, and forms precipitates. These precipitates are then blown off from the boiler. To ensure this process continues, a phosphate residual is maintained, usually in the range of 20 to 60 ppm.

Figure 22 – Phosphate Measurement

(a) (b)

Residual Phosphate Test Procedure

The check for residual phosphates may involve some form of colour comparison against a standard. An electronic meter may also be used to measure the phosphate residual. The following is a method of measuring phosphate in the boiler water, using the type of apparatus shown in Figure 22.

1. Take a representative sample of boiler water. Cool and filter the sample. If an unfiltered sample is used, the test will yield a false high phosphate reading. In this situation, the actual residual may be below the required control range.
2. Turn on the meter. The meter may have several different measurement programs. The correct type of test program must be selected.
3. Clean two glass cells. Fill one cell with 10 ml of deionized water. Fill the other with 10 ml of the filtered water sample.
4. Add 0.5 ml of molybdovanadate reagent to each cell, and mix with the water. Place one cell (the reference cell) into the cell holder, and then cover it (Figures 22(a) and (b)).
5. Start the instrument timer. When the timer expires, the meter is zeroed. The reading should show 0.0 mg/l PO_4^{3-}.
6. Remove the reference cell.
7. Insert the sample cell, cover it, and press **READ**. The display will show the phosphate concentration, in mg/l PO_4^{3-}.
8. Record this value on the water log sheet.

Operator Response to Residual Phosphate Test

Excessively high phosphate will cause foaming and carryover. Because phosphate is consumed, the phosphate concentrations will naturally fall in an operating boiler. In this case, reduce or halt the amount of phosphate fed to the boiler until the phosphate levels are within the control range. In cases of extremely high phosphate concentration, it may be necessary to increase continuous blowdown and bottom blowoff.

Excessively low phosphate will result in scale formation. Figure 22(b) shows a reading of 7.9 mg/L PO_4^{3-}. This is considerably below the control range. The operator should review the previous test, and check the trend. The phosphate feed rate should be increased. If there is an unusual drop in phosphate, hardness may be leaking into the boiler from damaged heat exchangers, cross-connections with untreated water, or malfunctioning water softeners. Condensate and softener effluent should be checked for hardness.

WATER TREATMENT LOG

The results of all of the water tests should be recorded on the water treatment log sheet. The log sheet should have a place for each piece of equipment in the plant, as well as, the prescribed control ranges. The operator compares the latest results with those of previous water tests, and then takes specific action based on test results. See Figure 23 for a sample log sheet.

Figure 23 – Sample Water Log Sheet

Main floor PEL - Boiler and feedwater systems

Test	Boiler #1	Boiler #2	Boiler feedwater #1	Boiler feedwater #2	Deaerator	Cooling water tank
Conductivity (as mmhos)	3500 max	1000 max	0 - 500	0 - 500	0 - 500	800 - 1000
Alkalinity P (ppm as $CaCO_3$)	300 - 600	300 - 600	5 - 80	5 - 80	5 - 80	
Alkalinity M (ppm as $CaCO_3$)	900 max	900 max				
Alkalinity OH (ppm as $CaCO_3$)	180 - 400	180 - 400				
Sulfite (ppm as SO_3)	20 - 40		5 - 20			
Phosphate (ppm as PO_4)	20 - 40	30 - 60	5 - 20			5 - 10
DEHA		10 - 300		5 - 250		
Chlorine free (ppm as Cl_2)						0.5 - 1
pH						8.5 - 9.2

Test	City water	Softener A	Softener B	RO system
Hardness, total (ppm as $CaCO_3$)	0 - 200	1 max	1 max	
Conductivity (as mmhos)	0 min	500 max	500 max	25 max

CHAPTER SUMMARY

This chapter described the types of impurities that could easily make their way into boilers, despite pretreatment. These impurities may result in:

- Acidic corrosion
- Caustic embrittlement
- Foaming
- Oxygen corrosion
- Scale formation
- Sludge deposits

For each problem, water tests, and appropriate operator responses, were described.

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CHAPTER 3

Condensate Treatment

LEARNING OUTCOME

When you complete this chapter you should be able to:

Discuss the general principles, methods, and equipment used for the treatment of condensate.

LEARNING OBJECTIVES

Here is what you should be able to do when you complete each objective:

1. *Describe condensate treatment and the effects of non-treatment.*
2. *Describe the tests conducted on condensate.*

CHAPTER INTRODUCTION

Great care must be taken to make sure that boiler make-up water is almost completely free of harmful impurities. All sources of boiler make-up water must be of high quality. This ensures that the water management program is effectively protecting the boiler systems.

Ideal steam systems recover all the produced steam as condensate. This yields great savings in water, chemicals, and heat. Recovered condensate should be pure, distilled water. The reality, though, is that new impurities often find their way into the condensate.

This chapter examines the most common impurities found in condensate. It also discusses ways to prevent the impurities from damaging boiler systems.

OBJECTIVE 1

Describe condensate treatment and the effects of non-treatment.

A steam system that does not reuse condensate relies on 100% make-up water. Such a system requires more external feedwater treatment, chemical input, heat input, and water input than a system that reuses condensate. These systems have greater associated costs, including water and sewer charges, chemical costs, and fuel costs. Strict environmental licenses may prohibit systems that use a significant percentage of make-up.

Condensate should be pure. It can also be quite hot. By recovering and reusing condensate, the overall cost of plant operations is reduced, and the environmental impact is minimized.

REASONS FOR TREATING CONDENSATE

Because it is essentially distilled water, condensate should be pure. However, this is not the case. Impurities enter condensate from a variety of sources, and in a variety of ways, including:

- Hydraulic oils, lubricants, and grease from mechanical equipment, such as pumps.
- Air intrusions from condensate return tanks.
- Corrosion products from condensate handling system components.
- Process fluids (such as hydrocarbons or hard water) from heat exchanger leaks.

Condensate must be treated for two main reasons:

1. Impurities can plug or corrode the condensate return and feedwater systems.
2. Impurities can scale up or corrode the boilers.

All of the condensate impurities listed above are of concern. However, this objective focuses on the following impurities:

- Carbon dioxide (CO_2)
- Oxygen (O_2)
- Hardness
- Corrosion products

Carbon Dioxide

Carbonates and **bicarbonates** enter boilers and steam systems in three main ways:

1. As alkalinity species originating in the source (raw) water supply.
2. Because of poorly functioning deaerators.
3. Through the introduction of sodium carbonate for alkalinity control.

In the boiler, carbonates and bicarbonates decompose to form carbon dioxide. This gas travels with the steam, and reacts with condensate to form carbonic acid (H_2CO_3).

$$CO_2 + H_2O \rightarrow H_2CO_3 \qquad (1)$$

This causes a general thinning of metal parts in the condensate return system. As well, carbonic acid causes localized grooving.

Many parts of condensate return systems are open to the atmosphere. At atmospheric pressure, the solubility of CO_2 is relatively low. This results in a carbonic acid solution with a pH no lower than about 5.8.

In an enclosed system, at elevated pressures, more CO_2 can enter and stay in solution, resulting in lower pH values. Concentrations of 85 ppm CO_2 in solution yield a pH of about 5.0 – a far more corrosive solution. Therefore, even a small amount of CO_2 in contact with condensate can produce corrosive solutions.

Figure 1 shows an example of grooving damage caused by prolonged contact with carbonic acid.

Figure 1 – Grooving in Metal

Oxygen

Oxygen enters the boiler make-up water or condensate through contact with air.

Improperly functioning deaerators can fail to remove dissolved oxygen, which leaves feedwater systems vulnerable to corrosion.

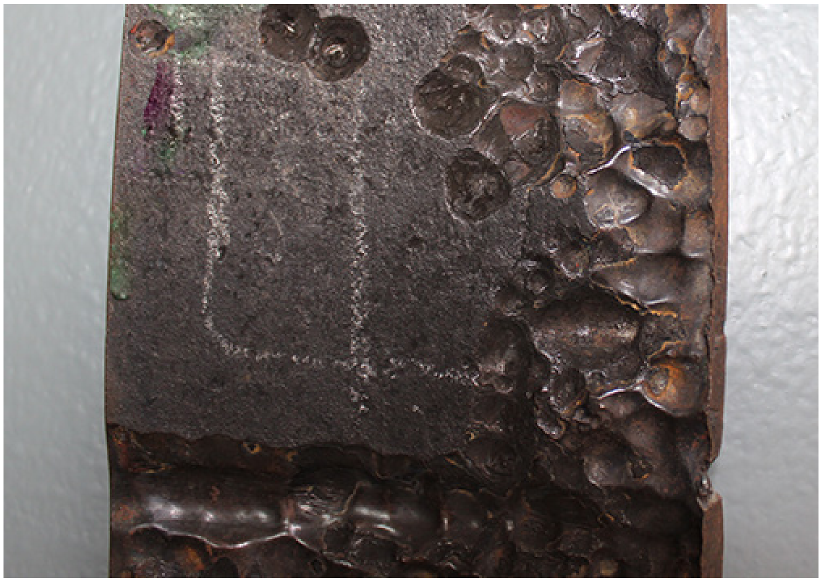
Air also enters condensate return systems when heat exchangers operate cyclically. During the off cycle, a vacuum breaker admits air to prevent the heat exchanger from collapsing. When steam is re-admitted, this air must be expelled. Steam trap air vents direct this air into the condensate discharge line.

Condensate return tank pumps also operate on a cyclical basis. When the return tank fills with condensate, the condensate return pump starts. As the return tank level drops, air is drawn in through the tank vent.

Oxygen can enter the condensate return system from boilers fed with improperly scavenged feedwater, and improper internal water treatment. In this situation, dissolved oxygen is liberated in the boiler, and travels with the steam until the steam condenses.

Oxygen corrosion often appears as pitting of metal surfaces. The pitting tends to occur at areas where the passive oxide layer is damaged, and it shows up as black oxides. Figure 2 shows oxygen pitting.

Figure 2 – Oxygen Pitting



Hardness

Hardness causes boilers to scale up. This reduces the rate of heat transfer, which results in poor boiler efficiency, increased operating costs, and the increased likelihood of boiler pressure component failure, due to overheating.

Hardness can enter the condensate system from leaking potable water heat exchangers, steam turbine condensers, and open cross-connections with potable water systems.

Corrosion Solids

In some cases, where the oxygen contamination is extremely high (such when steam is used for heating up equipment that is only used occasionally), it may not be worthwhile to re-use the condensate. It could be full of corrosion by-products, and is best sent to drain.

It should be noted that when both carbon dioxide corrosion and oxygen corrosion occur in a system, the total combined corrosion rate is significantly higher. To eliminate even one type of corrosion can have significant savings.

PREVENTING CONDENSATE LINE CORROSION

There are four main methods for combatting condensate corrosion:

- Mechanical inspection and maintenance
- Installation of dealkalization equipment in the external treatment systems
- Neutralizing amines
- Filming amines

Mechanical Inspection and Maintenance

Mechanical inspection, repair of leaks, and repair of steam traps will minimize the amount of make-up feedwater required, which will reduce the flow of some impurities into the system. This is also true for influx of air.

Properly heated and vented deaerators virtually eliminate dissolved CO_2 and O_2 from feedwater. This greatly decreases the potential for these gases to enter the boiler in solution. Ensure the deaerator is functioning properly.

In systems operating below atmospheric pressure, air can infiltrate condensate systems through pumps, valve packing, and turbine glands. Ensure that:

a) Packing glands are fed with sealing water.
b) Turbine glands are fed with gland steam or water.
c) Valve packing is tightened appropriately.

Dealkalization Equipment

Sodium zeolite ion-exchange softeners reduce hardness to zero. Two species of hardness are also alkaline: bicarbonates and carbonates. In a sodium zeolite softener, alkalinity enters with the raw water as calcium and magnesium salts. The effluent has the same concentration of salts, but converted to soluble sodium forms. Therefore, sodium zeolite softeners reduce hardness, but do not affect alkalinity.

If raw water alkalinity is high, it may be advisable to install a dealkalizer or demineralizer system to treat the raw make-up water. By reducing the make-up water alkalinity to zero, carbonates and bicarbonates cannot enter the steam system via make-up water. This will reduce the cost and complexity of condensate corrosion control.

Neutralizing Amines

Neutralizing amines increase condensate pH by neutralizing acid in the condensate system. This decreases the corrosion that occurs. Neutralizing amines can be fed either to the feedwater (after the deaerator), or to steam lines. They vapourize and travel with the steam. When the steam condenses, neutralizing amines dissolve in the condensate, which raises its pH.

The amine dosage depends on the amount of carbon dioxide in the steam. Residual levels in the condensate are usually kept at about 1 to 10 ppm (i.e. 1 to 10 mg/L).

The amines react with carbonic acid according to the following chemical reaction:

$$\underset{\text{(amine)}}{R\text{-}NH_2^{*}} \quad + \quad \underset{\text{(carbonic acid)}}{H_2CO_3} \quad \rightarrow \quad R\text{-}NH_3^{+} \quad + \quad \underset{\text{(bicarbonate)}}{HCO_3^{-}} \qquad (2)$$

******Note*: In the formula "$R\text{-}NH_2$", "R" is either alkane or an aromatic hydrocarbon group.

As can be seen by equation (2), neutralizing amines are really only effective on carbon dioxide corrosion rates. They have no effect on corrosion due to dissolved oxygen. The bicarbonate that forms returns to the boiler. There, it again decomposes to CO_2, and enters the steam flow. This is one reason why it is important to test and monitor boiler alkalinity, and maintain it within control limits through continuous blowdown.

Care should be taken not to add too much neutralizing amine. Over feeding can increase the system corrosiveness due to excessively high pH.

Metering pumps inject amine directly into the steam lines, so that chemical is not wasted through continuous blowdown or bottom blowoff. The amount of amine injected must be sufficient to maintain a condensate pH of between 8.8 and 9.2. This is confirmed by testing and monitoring trends in condensate pH, at various points in the condensate return system. One simple test involves a P-alkalinity check. If the condensate turns pink when phenolphthalein is added, the operator can be assured that the condensate pH is greater than 8.3.

If the boiler alkalinity is stable, the mass of CO_2 in the steam will vary with the rate of steam production. Therefore, feed rates are usually in proportion to steam flow.

Typical neutralizing amines used are:

- diethylaminoethanol (DEAE)
- methoxypropylamine (MOPA)
- diethanolamine (DEA)
- monoethanolamine (MEA)
- morpholine (volatile but good at high pressures)
- cyclohexylamine (volatile but good at high pressures)

Ammonia may be used to neutralize carbonic acid, but only in systems that do not have components made of copper, zinc, or nickel. For example, HVAC coils, steam turbine condensers, float operated switches, and pump impellers are commonly made of copper, or alloys of copper and zinc. The ammonium hydroxide that develops in the condensate will aggressively attack and corrode these parts.

Amines tend to have moderate flammability, and exposure to them should be limited. Review their SDS, and use appropriate PPE to handle them.

Filming Amines

Filming amines create protective films on metal surfaces. For this reason, filming amines are effective against the corrosive effects of both dissolved CO_2 and O_2.

Filming amines should be fed directly to steam lines, to reduce chemical loss due to blowdown and blowoff. Multiple injection points may be used to allow for optimum distribution.

Filming amines are longer-chain molecules which **adsorb** onto metal surfaces. This forms a very thin, sticky, oily type layer on the metal that protects it from corrosion. The layer may be as thin as a single molecule! As it adsorbs, filming amine tends to loosen and remove existing impurities, such as corrosion products. These particles are carried with the condensate, and will plug steam traps, strainers, and condensate lines. For this reason, when plants first start using filming amines, they must be introduced into the system gradually, so that deposition does not occur rapidly. This initial introduction is usually accompanied by increased boiler blowoff, to eliminate these particles from the system; and increased maintenance activities (unplugging strainers, condensate lines, and steam traps). Once the system is clean, higher levels of filming amine are administered.

Sometimes blends of both filming and neutralizing amines are used. The exact make-up of those blends is usually proprietary to the manufacturer.

CONDENSATE POLISHING

Condensate polishers are mixed bed ion exchangers, designed to purify condensate. They are used in situations where condensate may become contaminated with hard water, chlorides, silica, suspended contaminants, and corrosion products such as copper and iron particulate. These polishers filter out particulate and suspended matter, and perform ion exchange to remove hardness and chlorides.

These specialized ion exchangers are similar to those used in external feedwater treatment, described in Chapter 1 of this unit. Like all ion exchangers, their ion exchange and filtration abilities become exhausted. Therefore, they require regular backwashing and regeneration.

Condensate polishing is essential for high-pressure boilers, where feedwater purity is critical. Figure 3 shows a small condensate polisher.

Figure 3 – Condensate Polisher

Pre-filters can be used if there is evidence of oil or other process fluids in the condensate. Such contaminants foul ion-exchange beads, and must be removed before they can contact the **ion exchange resin**.

OBJECTIVE 2

Describe the tests conducted on condensate.

CONDENSATE TESTING

The primary tests conducted on condensate are:

- pH readings
- hardness tests
- conductivity measurements (for determining condensate purity)
- corrosion byproduct monitoring (e.g. iron oxides, copper oxides)

These first three tests were detailed in the previous chapter.

For corrosion products, a commercially available iron analysis kit can be used. Some wet chemistry tests will measure the amount of dissolved iron in a sample. For most purposes, readings below 0.5 ppm should be considered acceptable. Similar tests are available for copper analysis.

Direct amine measurements can be made using a chromatograph. A condensate sample is taken using a grab-sample bag. The sample is sent to a lab, where it is run through a chromatograph to determine what molecules are present.

Some facilities may pump a sample to a continuous **fluorometer**. This device measures and monitors the condensate amine concentration. Some are capable of controlling amine feed rates, and issuing an alarm when amine levels are outside of the control range.

Samples should be taken at all critical points. This includes steam sections, condensate sections, and at any equipment that is critical to the operation, or has a history of corrosion.

Operators taking samples should make sure that:

- The sample is cooled to less than 32°C (90°F).
- The sample flow is throttled at the outlet of the sampling system.
- Stainless steel lines are used.
- An adequate flow of material occurs (1.5 – 2.0 m/s).
- The sampling device is purged.

Corrosion Coupons

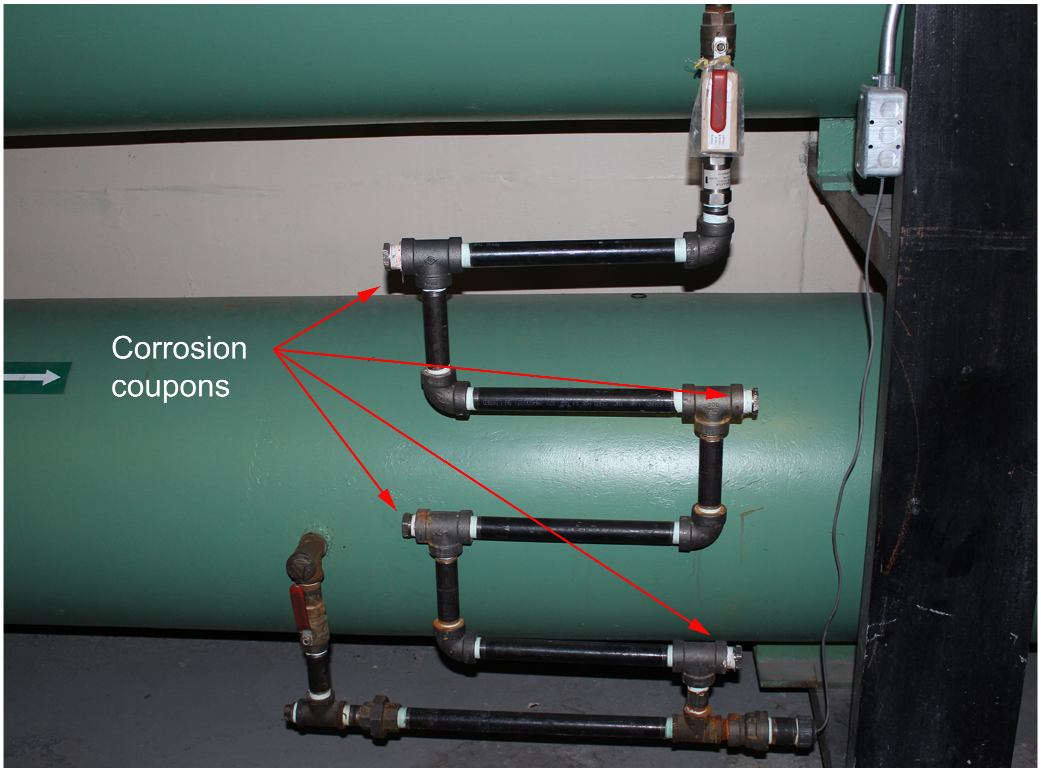
Corrosion coupons are an inexpensive, and simple way to evaluate corrosion rates. They are only useful at estimating average corrosion rates. They do not provide instantaneous readings of system corrosiveness. They are useful, though in determining how corrosive a system is becoming.

Coupons are metal strips of known mass. They are as close as possible to the composition of the piping system. They come in various shapes (strips, rods, discs).

Coupons are immersed in condensate for a period of time in a coupon rack. Several coupons may be held in a rack similar to the one shown in Figure 4. After 1 to 3 months, the coupons are removed. Then, they are cleaned of system contaminants, dried, and weighed. The difference in weight over time gives an approximate corrosion rate, expressed in mils per year.

Often the most metal loss will occur in the first month as a passive layer forms. For this reason, coupons that have been in place for only a month should not be compared to coupons in place for three months.

Figure 4 – Corrosion Coupon Rack



Before insertion, never handle coupons with bare hands. Any oil, grease, or dirt transferred to the coupon will affect the results.

Galvanic corrosion can also negatively affect the test results. To prevent this corrosion, the coupons are usually held in place with Teflon bolts.

CHAPTER SUMMARY

Because it is important to reuse as much condensate as possible, Power Engineers are often chosen to manage the entire source water treatment and water reuse processes.

This chapter examined water reuse systems, and how these systems deal with condensate impurities. The impurities discussed in detail included dissolved gases, dissolved solids, and suspended matter. The effect of dissolved gases on condensate line corrosion was examined in detail, and corrective measures were enumerated. These included chemicals, and equipment to neutralize and purify condensate.

Different ways of determining condensate corrosiveness, and how to monitor system corrosion rates were also explored. These included:

- pH tests
- Conductivity tests
- Corrosion coupons
- Continuous amine monitoring systems

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CHAPTER 4

Cooling Tower and Condenser Water Treatment

LEARNING OUTCOME

When you complete this chapter you should be able to:

Discuss the general principles, methods, and equipment used for the treatment of condenser water, and their effects on the cooling tower.

LEARNING OBJECTIVES

Here is what you should be able to do when you complete each objective:

1. *Describe the effects of water on condensers and cooling tower materials.*
2. *Describe condenser and cooling tower water treatment.*
3. *Describe cooling tower and condenser water tests for common treatment methods.*

CHAPTER INTRODUCTION

Water is often called a universal solvent. Given enough time and the right conditions, almost everything will dissolve in water. This presents a problem for plant systems that use water as a major process fluid, especially condensers and cooling towers.

This chapter looks at some of the water impurities that affect condensers and cooling towers, their effects, and how to minimize those effects. Knowledge of how condensers and cooling towers work, and an understanding of boiler water treatment, is helpful when studying this chapter.

OBJECTIVE 1

Describe the effects of water on condensers and cooling tower materials.

COOLING TOWER WATER PROBLEMS

Cooling towers, by design, consume a lot of water. This water contains impurities that can, if left untreated create significant operating problems. These lead to increased operating costs, and ultimately to equipment failure.

There are several sources for the impurities in cooling water. Their origins are varied, including:

- **Avian waste**
- Contact with the atmosphere
- Raw make-up water

These sources lead to the following problems:

- Deposition of solids (scaling)
- Corrosion
- Plugging or erosion of equipment
- Biological fouling
- Wood deterioration

Deposition of Solids (Scaling)

Initially, water in cooling towers may have few impurities. However, water evaporates in the towers, and leaves behind dissolved solids. As more water evaporates, the concentration of dissolved solids increases. This leads to deposition of solids (scaling) in condensers and on cooling tower evaporative surfaces (louvres).

Since the operating temperatures are much lower, scaling in cooling towers is not as severe as in boilers. It normally results from dissolved calcium bicarbonate, a naturally occurring soluble salt, as it breaks down when heated.

The reaction is:

$$Ca(HCO_3)_2 \rightleftharpoons CaCO_3\downarrow\text{(scale deposit)} + CO_2\uparrow\text{(gas release)} + H_2O \qquad (1)$$

The degree of scaling depends primarily on the concentration of calcium and bicarbonate ions in solution and the pH of the cooling water. When there is a rise in both the pH and the water temperature, it increases the rate at which the calcium bicarbonate breaks down and forms scale.

Scaling increases operating costs, as well as the possibility of under-deposit corrosion.

Corrosion

In cooling systems, corrosion can cause:

a) Equipment failure, which increases operating costs and results in more plant downtime.
b) Loss of heat transfer efficiency due to heat exchanger fouling (from the accumulation of corrosion product).
c) Loss of structural integrity of concrete walls and basins.

Corrosion results in the loss of metal from direct chemical or electrochemical reactions. The principal cause of steel corrosion in cooling towers is dissolved oxygen in the cooling water. Under certain conditions, the oxygen combines with the steel to form rust (iron oxide).

$$4Fe + 3O_2 \rightarrow 2Fe_2O_3 \qquad (2)$$

When the concentration of dissolved oxygen in the water increases, the rate of corrosion also increases. Since cooling towers continually aerate the water, the amount of dissolved oxygen is high. Normally, water at 20°C contains about 9.1 ppm dissolved oxygen. At 30°C, the concentration decreases to about 7.6 ppm.

Acidity promotes corrosion by increasing both the dissolution rate of the base metal, and the oxide formation on the metal surfaces. Surprisingly, even a neutral pH of 7.1, or a slightly alkaline pH of 7.5, can be corrosive.

Higher temperatures will generally cause corrosion rates to double with every 10°C rise in temperature, up to about 70°C. Increases above 70°C have relatively little effect on corrosion rates in cooling water systems.

Plugging or Erosion of Equipment

Most towers are open to atmosphere. Airborne dust and debris can enter the water, and eventually plug up the system.

Other sources of plugging include:

- Dirt
- Sand
- Corrosion products
- Natural organics
- Aluminum phosphates
- Iron phosphate

Biological Fouling

Algae, fungi, avian waste, and bacteria growth cause **biological fouling** of recirculating cooling towers. Uncontrolled growth of these organisms is a substantial threat found in cooling towers. Biological fouling is enhanced by:

- Warm water
- Abundant sunlight
- An oxygen-rich environment

These organic growths, called slime or **biofilm**, can:

- Reduce flow rates in tubes and channels.
- Release organic acids and waste products that can corrode metals.
- Attack and destroy the wooden portions of a tower.

Biofilms are even less thermally conductive than calcium deposits. This can reduce heat exchanger efficiency and increase operating costs.

Many different biological growths can appear in a cooling tower, often at the same time. One of the more critical ones is the **Legionella bacteria**. It came to the public's attention prominently after a 1976 American Legion convention in Philadelphia, Pennsylvania. Over 2000 legionnaires attended the conference. Of those, 221 contracted the disease, and 34 of them died.

Legionella is a bacteria that causes a serious lung infection (a type of pneumonia), or a less serious flu-like infection (**Pontiac fever**). There is no vaccine for it, so prevention is the only option. Legionella is a natural bacteria, and not usually a problem in lakes and streams. However, according to the **Centers for Disease Control and Prevention (CDC)**, some human-made systems can increase the growth and spread. These include:

- Cooling towers
- Hot water tanks and heaters
- Hot tubs
- Decorative fountains

Legionella spreads in mists and water droplets that can be breathed into the lungs. People older than 50, current or former smokers, people with chronic lung disease, and people with weak immune systems are at increased risk of developing Legionella.

Legionella can survive in biofilms, from which it extracts the required nutrients.

Wood Deterioration

Many cooling towers contain wooden components which may be subject to biological and chemical attack, resulting in deterioration. Wood is composed of **cellulose**, **lignin**, and natural extractives (non-structural components).

Cellulose exists as long fibers, and gives wood its strength. Lignin cements the cellulose fibers together. The extractives contain the natural compounds that enable wood to resist decay. Unfortunately, these extractives are water-soluble. They leach away, and leave the wood in cooling towers vulnerable to decay.

Chemical attack occurs mainly as **delignification**. Oxidizing agents, such as chlorine and alkaline solutions, are its main agents. To control it, use non-oxidizing biocides, or keep the chemical concentration of oxidizing agents sufficiently low.

Biological attack on cooling tower wood occurs when the cellulose deteriorates. This creates a source of carbon for the growth and development of microorganisms.

These and other potential impurities have an impact on cooling towers, the environment, and on human health. Therefore, environmental organizations in different countries have developed water quality guidelines for cooling tower water. In Canada, the **Canadian Council of Ministers of Environment** published its guidelines in November 2008. Table 1 summarizes these guidelines. Suggestions include keeping water pH in the range of 6 to 8, and total dissolved solids less than 2500 mg/L.

Table 1 – Water Quality Guidelines for Cooling Towers

Parameter	Limits	Comments
pH	6 - 8	
Calcium as ($CaCO_3$)	30 - 300 mg/L	30 – 400 mg/L for Chromate programs
Total Iron	< 0.5 mg/L	
Manganese	< 0.5 mg/L	
Copper	< 0.08 mg/L	
Aluminum	< 1 mg/L	
Sulfide	< 5 mg/L	
Silica	< 150 mg/L	< 200 mg/L For pH > 7.5
Total Dissolved Solids	< 2500 mg/L	
Conductivity	< 4000 μS/cm	
Suspended Solids	< 150 mg/L	

A typical cooling tower is shown in Figure 1. It gives an indication of the size and volume of water that may be handled. The large white "cloud" seen above a power plant is often water vapour from the cooling towers.

Figure 1 – Cooling Tower

OBJECTIVE 2

Describe condenser and cooling tower water treatment.

SOLUTIONS TO COOLING WATER PROBLEMS

The five major problems noted in the previous objective can be addressed by using appropriate water treatment. The treatments discussed in this objective are typical of most plants. However, most plants have treatment programs that are custom tailored by reputable water treatment specialists to meet specific needs. Therefore, it is necessary to follow site-specific water treatment procedures and guidelines.

Deposition of Solids (Scaling)

Currently, the main method of reducing deposition of solids is with sequestering agents and chelates. These products work to reduce the solids, and keep them in suspension, so they can be blown down. Keeping the **cycles of concentration** low is important for keeping deposits to a minimum. Maintaining pH levels is also important. Higher pH promotes the deposition of solids. Lower pH (6.5 to 7) helps keep solids in suspension. Plants that use source water with high hardness may also add sulfuric acid to keep the pH in the lower range.

Specialty chemicals are added to keep scale-forming salts in solution at high concentration levels. The most common chemicals used are polymeric organics (polyaculates) and organic phosphorus compounds. However, some of these compounds can accelerate corrosion of steel and copper. Some older types of chemicals can be completely destroyed by chlorine which is added to control biological growth. However, newer chemical mixes retain their effectiveness, regardless of chlorines and other biological control chemicals.

Cooling towers must be balanced with complementary corrosion and biological controls. Operators should be aware that severe scaling can occur rapidly if these chemicals are not maintained in the cooling water. Continuous and uniform feed is necessary; otherwise, heavy scale can form within minutes.

The following are other methods that prevent the formation of calcium scale in cooling water systems:

- Remove calcium hardness from the water with a softening process prior to use.
- Keep scale-forming salts in solution.
- Precipitate the calcium as a removable (soft) sludge rather than as a hard scale.

To soften the water, use either an ion exchange softener, or cold-lime softening. The cold-lime method involves the addition of lime (calcium hydroxide - $Ca(OH)_2$). It causes the calcium carbonate to precipitate out in a settling tank, before the water enters the cooling system. Softening is used mostly for industrial situations, where the large quantity of tower make-up water justifies the initial capital cost, and the ongoing operating expense.

Crystal modification chemicals promote the formation of soft sludge. The chemicals attach themselves to precipitating solids, and prevent the crystals from consolidating into a hard scale. These chemicals are low molecular weight polymers, such as polymaleic acids and sulfonated polystyrenes. The sludge is removed either by blowdown, from the tower basin, or by side-stream filtration. When crystal modifiers are used, the cooling water should appear turbid, which indicates that they are taking effect.

An important cooling tower term is **cycling control**. This refers to the maintenance of the appropriate ratio of dissolved solids in the circulating water, to the dissolved solids in the make-up feedwater. Cycles can be calculated using parameters, such as chloride ion concentration. For example, if the raw water has 10 ppm of Cl^- and the cooling water has 100 ppm of Cl^-, the cooling tower is said to be operating at 10 cycles of concentration.

Cooling towers that operate at higher cycles of concentration require less blowdown. This minimizes make-up water consumption, sewage disposal, and the related water and sewer charges. However, operating at these higher cycles also increases the possibilities of deposition in the water system, and will increase heating costs. So, a balance must be found to keep costs at a minimum. The optimum cycles of concentration vary from site to site. Generally, it is between 3 and 6, and usually never higher than 10.

The two most used methods for cycle control are:

1. Make-up proportional blowdown
2. Conductivity-based blowdown

Make-up proportional blowdown is directly related to the amount of make-up water added to the cooling tower. The amount is measured, and triggers a timer on a blowdown line. This allows a proportional blowdown discharge. For example, if 100 litres of make-up water were added to a system operating at 4 cycles, the blowdown would allow a discharge of 25 litres (1/4 of the amount entering).

In **conductivity-based blowdown**, the blowdown valve is opened when a predetermined conductivity value is reached. While proportional blowdown is less expensive to install and maintain, the conductivity-based blowdown is more sensitive to system upsets (such as leaks). The conductivity-based system also has a potential pitfall for operators. If calcium carbonate forms, it lowers the conductivity and gives a false sense of security. This also means that blowdown fails to occur, which can result in more deposits.

Self-Test 1

A cooling tower is fed with make-up water that has a chloride ion concentration of 9.1 ppm. A chloride test on the cooling water shows a concentration of 48 ppm. What is the number of concentration cycles?

5.3 cycles (Ans.)

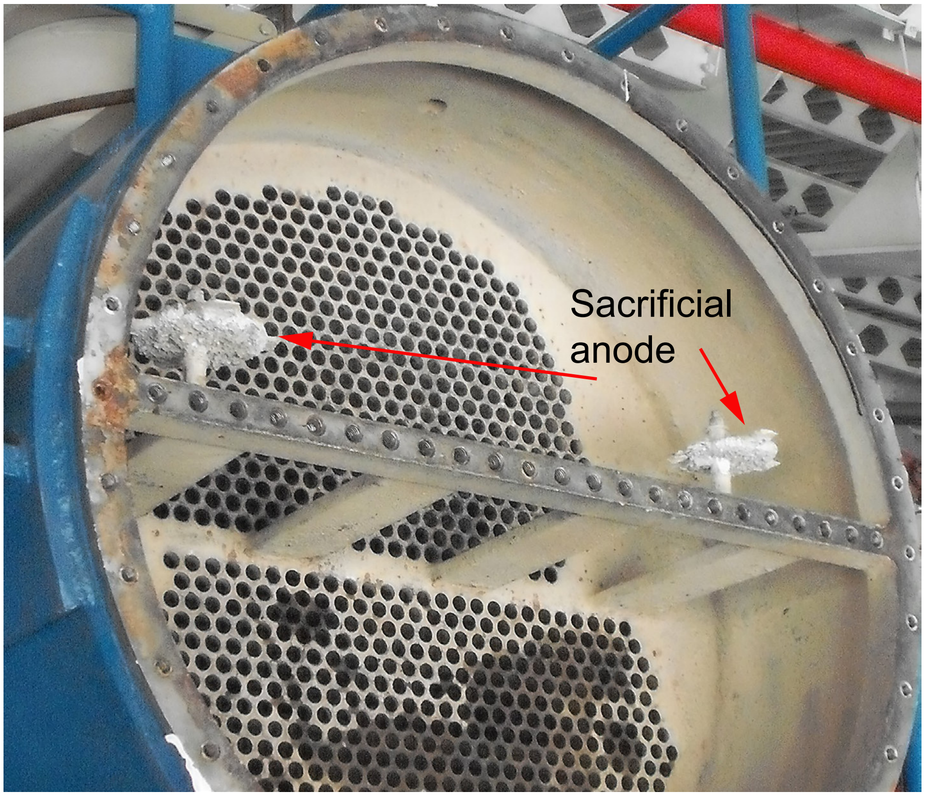
Corrosion

In most cases, a good water treatment system will not entirely eliminate corrosion. However, it should reduce the rates to an acceptable level, as determined by the plant water treatment specialists.

The following are basic methods of corrosion control in cooling water systems. They can be utilized by themselves or in combination.

- Use corrosion resistant metals and materials.
- Apply protective coatings, such as paint, metal plating, or epoxy.
- Use **sacrificial anodes**, induced electric currents, or both, to direct corrosion to sites where it can be tolerated or accepted. Sacrificial anodes, installed in a chiller condenser, are shown in Figure 2.
- Form protective films with chemical inhibitors that are fed into the cooling water, and transported to the metal surfaces.

Figure 2 – Sacrificial Anodes



The use of chemicals to form protective layers is more commonly referred to as the use of chemical inhibitors. These inhibitors are generally classified in three categories:

1. Cathodic
2. Anodic
3. General

Cathodic inhibitors coat the cathodic surfaces of a system. Examples of these inhibitors include:

- Bicarbonate
- Polyphosphate
- Zinc

Anodic inhibitors coat the anodic surfaces of a system. When using these, the operator must make sure enough chemicals are added to cover all of the anodic regions. Otherwise, the corrosion effects can worsen. If the coating is incomplete, the cathode-to-anode ratio increases, thus concentrating corrosion on a smaller anodic surface. Examples of these inhibitors include:

- Molybdate
- Orthophosphate
- Nitrite

General inhibitors cover all the regions of a system, regardless of whether they are anodic or cathodic. These inhibitors include:

- Soluble oils
- Triazoles for copper

The traditional film-forming chemicals used are polyphosphates, chromates, and zinc. These are often used in combination with each other, to counterbalance severe side-effects. For example, polyphosphate has a tendency to attack copper and aluminum, while it is protecting steel. These chemicals form a thin film on the metal. This prevents dissolved oxygen and carbon dioxide in the water from coming in direct contact with the metal.

While effective at corrosion control, chromates cause unacceptable environmental damage when released through blowdown or system drainage. Therefore, chromate is no longer used in systems from which water can escape. Nontoxic alternatives include zinc, polysilicates, and molybdates. However, they can be more expensive than the traditional treatments.

The speed with which inhibitors form their protective film varies considerably. Polyphosphate and zinc take about 5 days. Polysilicates and molybdates can take up to 2 weeks. The inhibitor must form a film on the entire metal surfaces. If the initial concentration of the inhibitor is too weak, there is a good possibility of severe corrosion occurring at unprotected sites, since the entire corrosion potential will be concentrated there. In this case, rapid and severe pitting can occur.

Plugging or Erosion of Equipment

Screens and filters prevent the influx of solid matter, and protect against plugging and erosion. A good engineering practice is to install a Y-strainer, or equivalent, upstream of the blowdown valve to prevent plugging.

Erosion and deposition are dependent on fluid flow rates. Deposition occurs when the flow is too slow. Erosion occurs when the flow is too great.

Biological Fouling

There are two types of methods to protect against biological fouling:

1. Mechanical methods, such as trash bars and strainers
2. Chemical methods that kill the microorganisms

Chemical methods operate in several ways. Heavy metals penetrate the cell wall and destroy protein groups that are essential to life support. Oxidizing chemicals, such as chlorine, irreversibly oxidize protein groups. This results in a loss of enzyme activity in the cell, and causes the cell to die. Non-oxidizing chemicals, such as chlorinated phenols, pass into the cells. They cause precipitation of proteins out of solution inside the cell, and kill the cell.

Operators should be aware that biocides are poisonous. Use extreme caution when working with both feed and blowdown systems. Precautions include rubber gloves, protective clothing, and eye protection.

Biocides only work in concentrations greater than a minimum dosage, and maintained for a set amount of time. The dosage will vary, dependent on the biocide and the system. Unfortunately, most biocides tend to increase the corrosive nature of the cooling water. Some, such as chlorines, can produce by-products that may be carcinogenic.

The following may be used as a starting point for biocide volumes:

Standard cooling tower systems	60 millilitres/tonne
Evaporative condenser systems	8 millilitres/tonne

The effectiveness of biocides is determined by their types and feeding schedule. Biocides are shot-fed at toxic concentrations into the cooling system, usually twice a week. This method is called shock feeding. It kills microbiological organisms most effectively by creating a temporary high concentration of a biocide.

Shock feeding only one type of biocide will cause organisms to become immune. To prevent this from happening, once a month an alternate biocide is shot-fed for one week. This kills off organisms that developed immunity to the first biocide. Alternatively, a combination of different biocides can be used simultaneously.

To prevent dead microbiological growth from fouling the cooling system, add dispersants during biocide slug feedings. This holds the dead growth in suspension, until it is removed through blow off.

There is no specific biocide for Legionella. However, common oxidizing biocides , such as chlorine and bromine, have been effective at controlling it.

Wood Deterioration

Methods to control wood deterioration include:

a) Choose woods that have a natural resistance to biological attack, such as redwood.

b) Treat with wood preservatives, such as creosote or chromated copper arsenate, among others.

c) Limit the use of nails, screws, or iron hardware. These accelerate deterioration of the wood in their vicinity.

d) Treat water with biocides.

OBJECTIVE 3

Describe cooling tower and condenser water tests for common treatment methods.

COOLING TOWER AND CONDENSER WATER TESTING

There are several reasons for monitoring. Among them are to:

a) Gather information about how the equipment is operating.
b) Identify and target issues before they become problems.
c) Reduce operating costs.
d) Increase the life span of plant equipment.

To prevent the problems associated with cooling water, the operator performs various activities:

a) Conductivity tests
b) Corrosion tests
    - Coupons
    - pH measurements
c) Solids maintenance
d) Biological activity measurements
e) General inspections

Conductivity Tests

Conductivity tests are used to determine dissolved solids concentrations. As conductivity increases, so too does the dissolved solids content.

Often these measurements are automated. Despite this, operators should take manual tests to validate the operation of the automatic test equipment. Readings and test results should be recorded and tracked, so that trends can be identified.

Corrosion Tests

There are two main corrosion tests operators perform: pH tests and corrosion coupon tests. The pH tests and corrosion coupon tests have been discussed in detail in previous chapters.

In cooling water systems, low pH contributes to system corrosion, and high pH contributes to accelerated scale deposition. To minimize these conditions, the operator must try to keep the system within a set pH range.

Corrosion coupons give the operator a relative measurement of how corrosive a system is.

Solids Maintenance

The main operator activity around solids maintenance is to ensure that filters and strainers are cleaned on a regular basis.

If necessary, the operator can take a cooling water sample, and run a suspended solids test. This involves filtering the sample, and measuring what remains trapped by the filter paper.

Biological Activity Measurements

Differential Microbial Analysis (DMA) is a test to detect various microorganisms. It is conducted on a periodic basis in an off-site laboratory.

For quicker results, the weekly use of dip slides is highly recommended. Dip slides are plastic carriers bearing a sterile culture medium. They are dipped into the cooling tower water, returned to a sterile plastic bottle, and then incubated (usually kept at 30°C for 24 – 48 hours) allowing bacteria to grow. After incubation, the slides are compared to a chart and the number of bacteria is determined in cfu/ml (**cfu** is an abbreviation for **colony forming unit**). The slides would appear similar to those shown in Figure 3. They would then be compared to a chart, such as the one shown in Figure 4, and the number of bacteria estimated in cfu/ml. If results are high (greater than 1×10^4) and similar in appearance to slide (c) below), further action should be taken:

- For 10^4 to 10^5: take another sample, and review operating procedures.
- Greater than 10^5: shot-feed biocide, take another sample, and review operations.

Figure 3 – Biological Dip Slides

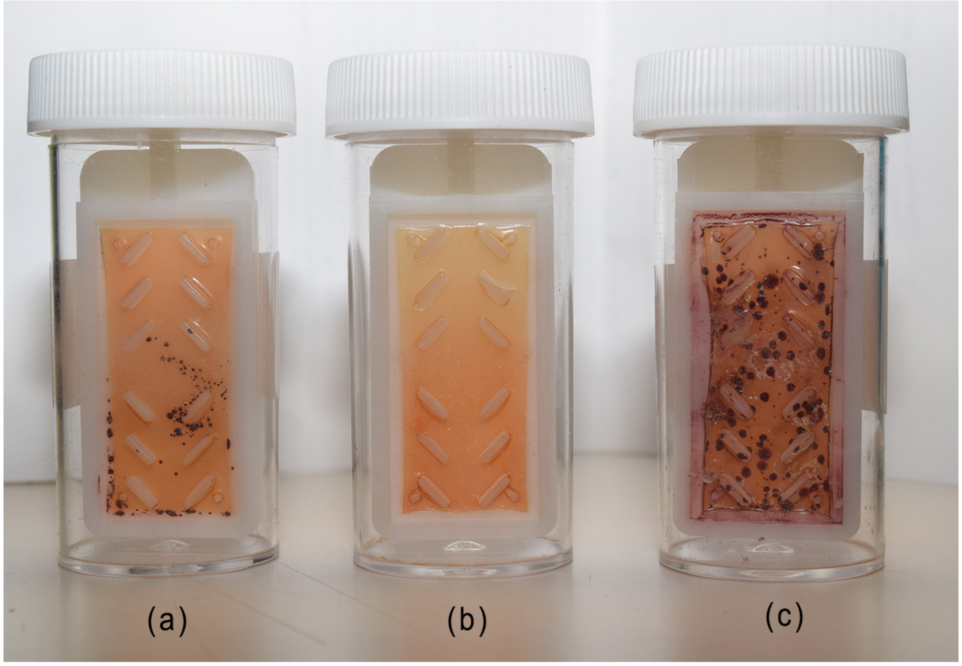
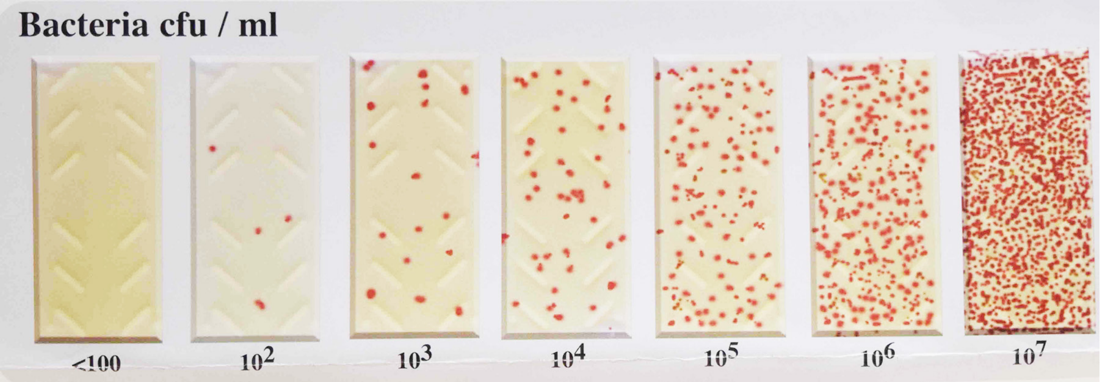


Figure 4 – Biological Comparison Chart



If the readings continue to be high, shock the system with a large one-time biocide dose.

On Track

Dip slides do not provide precise measurements. However, they are very useful for determining trends in bacterial activity.

General Inspection

Operators play critical roles, even in highly automated systems. They must ensure that:

a) Empty chemical tanks are replaced.
b) Leaks are found and repaired.
c) Conductivity and dip slide tests are conducted periodically.
d) Ongoing visual and operational checks of equipment, such as feed pumps, are done.
e) The interior of the cooling tower is inspected, to check on the structure integrity and flow distribution.
f) Equipment is visually inspected, to ensure there are no leaks or stuck valves.

CHAPTER SUMMARY

This chapter discussed the potential problems in cooling tower water, such as:

- Scaling
- Corrosion
- Plugging of mechanical equipment
- Biological activity
- Wood degradation

Treatment and preventative options were suggested. These mainly revolved around good engineering material selection and chemical treatment.

Cooling towers run well under automated water treatment systems. However, operators remain an important part of the process, and must be diligent in monitoring the system.

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CHAPTER 5

Recirculating System Water Treatment

LEARNING OUTCOME

When you complete this chapter you should be able to:

Describe recirculating water systems, their effects, treatment, and tests.

LEARNING OBJECTIVES

Here is what you should be able to do when you complete each objective:

1. *Describe recirculating water system corrosion and deposition.*
2. *Describe the use of sacrificial anodes, and measurement techniques to determine corrosion.*
3. *Describe glycol system testing requirements.*
4. *Discuss the monitoring tools, procedures, and tests used in recirculating water systems.*

CHAPTER INTRODUCTION

Water is a nearly ideal heat transfer fluid. It has a high latent heat capacity, and a high specific heat. It is also safe to handle, inexpensive, and readily available.

However, water is an effective solvent, a powerful electrolyte, and a supporter of biological growth. These factors create unwanted side effects in closed loop heat transfer applications. These include:

- Corrosion
- Scale deposition
- Growth of biological organisms

These side effects are controlled using mechanical, chemical, and electro-chemical means.

This chapter examines the conditions that occur in closed loop heat transfer systems that can lead to corrosion, scale formation, biological growth, and fouling. It then highlights treatment methods that promote equipment efficiency, longevity, and reliability.

OBJECTIVE 1

Describe recirculating water system corrosion and deposition.

CLOSED LOOP SYSTEMS

Closed loop systems are often associated with:

- Chilled water-cooling systems
- Hot water heating systems
- Internal combustion engine cooling systems

These systems recirculate the working heat transfer fluid, and use minimal amounts of make-up water. Very few impurities are introduced after the system is initially filled and treated. The heat exchange fluids may be treated water, **glycol** solutions, or salt brines.

Chillers are heat exchangers that cool fluids. The process fluid (chilled water or brine) is continuously circulated in a closed loop. The chiller may use refrigerant or some other cold process fluid to chill the water.

See Figure 1. The light blue lines show the extent of the chilled water loop. The chilled water is circulated by pump through other heat exchangers, where it absorbs heat. Then, the water returns to the chiller to reject the heat it absorbed. The chilled water is recirculated, and make-up is minimal.

Figure 1 – Closed Loop Chilled Water System

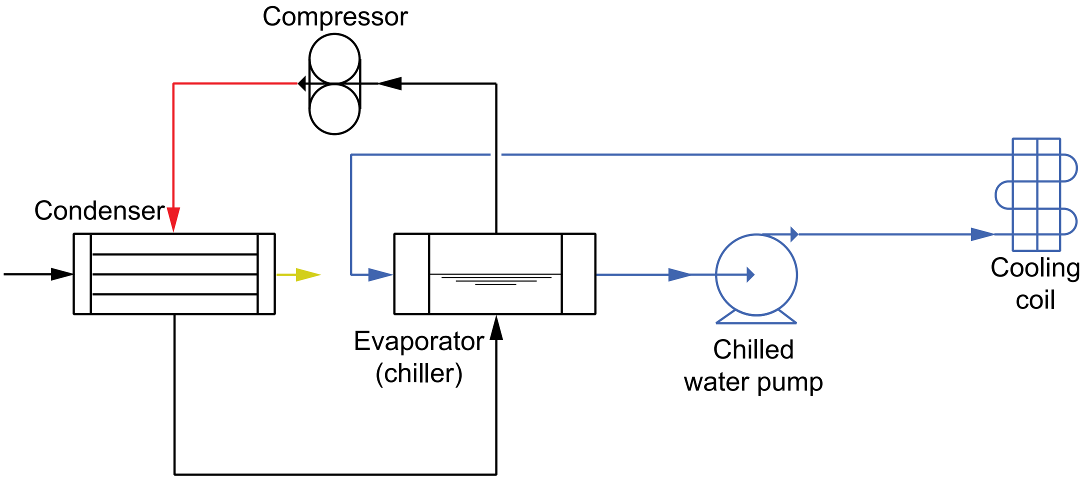
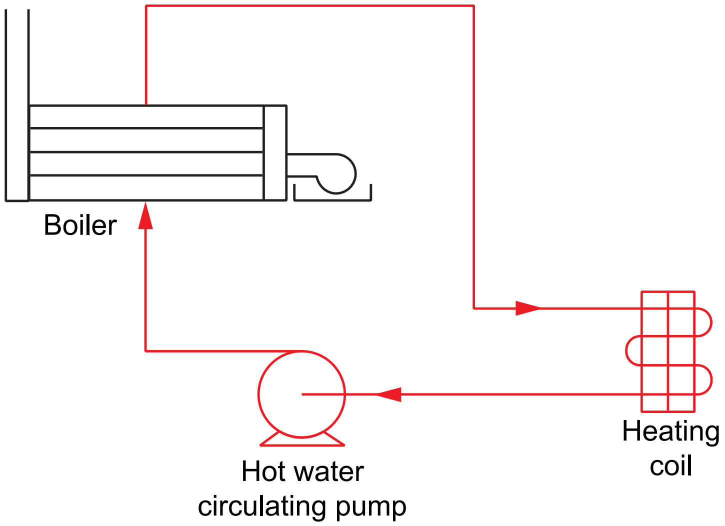


Figure 2 shows a simple closed loop system used for heating. The closed loop heating system is shown in red. This particular system uses a boiler to provide heat. Some heating systems use steam or hot water heat exchangers instead of a boiler. Again, the water is recirculated, and make-up is minimal.

Figure 2 – Closed Loop Hot Water System



Despite being enclosed, and using minimal make-up water, closed loop cooling and heating systems both suffer from the same water quality issues. These are:

- Corrosion
- Solids fouling
- Scaling
- Biological fouling

COOLING SYSTEMS

Corrosion

Chillers operate at much lower temperatures than boilers or condensers. So, the corrosion rate associated with oxygen is not as great as in higher temperature systems. In chillers, it is more likely that corrosion will result from galvanic action.

Galvanic corrosion occurs when dissimilar metals, such as copper and mild steel, are in physical contact with each other, and exposed to a fluid. This transfers electrons and metal ions between the two metals. The metal that gives off ions will waste away and fail.

Heat exchangers are usually constructed of both steel and copper alloys. When heat exchangers, piping systems, and piping components are in contact with aqueous process fluids, numerous galvanic cells may be created, and corrosion occurs. This process will be discussed in more detail in the next objective.

Corrosion is also likely to occur wherever deposits form. Therefore, it is important to keep heat exchangers free of deposits. This usually entails periodic cleaning and inspection. As well, heat exchangers should be installed so that the fluid most susceptible to fouling is admitted to the side of the heat exchanger that is easiest to clean. For example, in a straight-tube heat exchanger, condenser water is admitted to the tube-side, because the straight tubes are relatively easy to clean. However, in a U-tube heat exchanger, the condenser water would be admitted to the shell side, because the tight U-bends are extremely difficult to clean.

Corrosion is accelerated by excessively high or low fluid flows. If the fluid flow is too high, erosion can occur at piping turns. This will expose more bare metal to the effects of corrosion. High fluid flows can strip protective chemical coatings from pipe and heat exchanger surfaces, leaving them unprotected and susceptible to galvanic corrosion.

If the fluid flow is too low, suspended materials can drop out and deposit on metal surfaces. Galvanic corrosion cells form under these deposits.

Chemicals may be added to eliminate corrosion. Two closed system corrosion inhibitors in common use are:

- Sodium nitrite
- Molybdate

Sodium nitrite is an anodic corrosion inhibitor that forms a protective iron oxide surface film. It offers excellent corrosion protection for ferrous metals, but is not a good corrosion inhibitor for copper or copper alloys. Nitrite can also scavenge dissolved oxygen, which forms sodium nitrate. In one regard, this is beneficial, because it binds dissolved oxygen, and reduces oxygen attack. However, the nitrate that results does not form corrosion preventative films. Therefore, it is necessary to periodically check and adjust nitrite concentrations to the proper control range. Also, nitrites promote biological growth within cooling systems.

For systems of mixed metallurgy (such as aluminum, steel, and copper), molybdate inhibitors provide the best corrosion protection.

Figures 3 and 4 show the relative corrosion protection provided by these two chemicals. Both are effective at protecting ferrous metal surfaces. Nitrite, however, does not protect brass as well as molybdate does, regardless of the concentration. Also, observe that for molybdate to be as effective at reducing corrosion in steel systems, it must be maintained at higher concentrations than nitrite. Blends of molybdate and nitrite work well in closed loop systems.

Figure 3 – Molybdate and Nitrite Comparison: Steel Systems

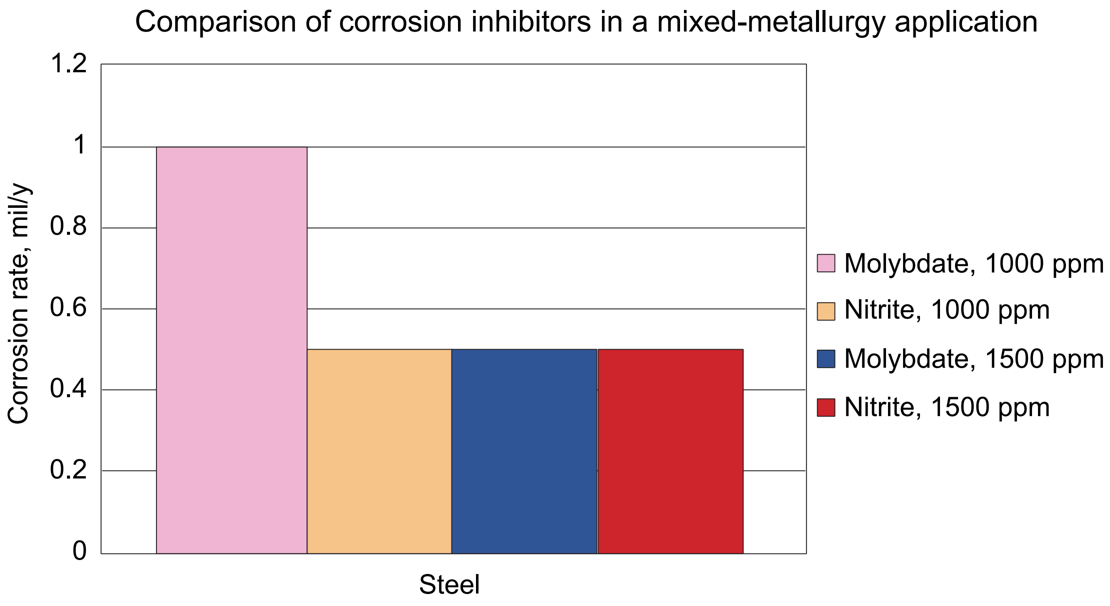
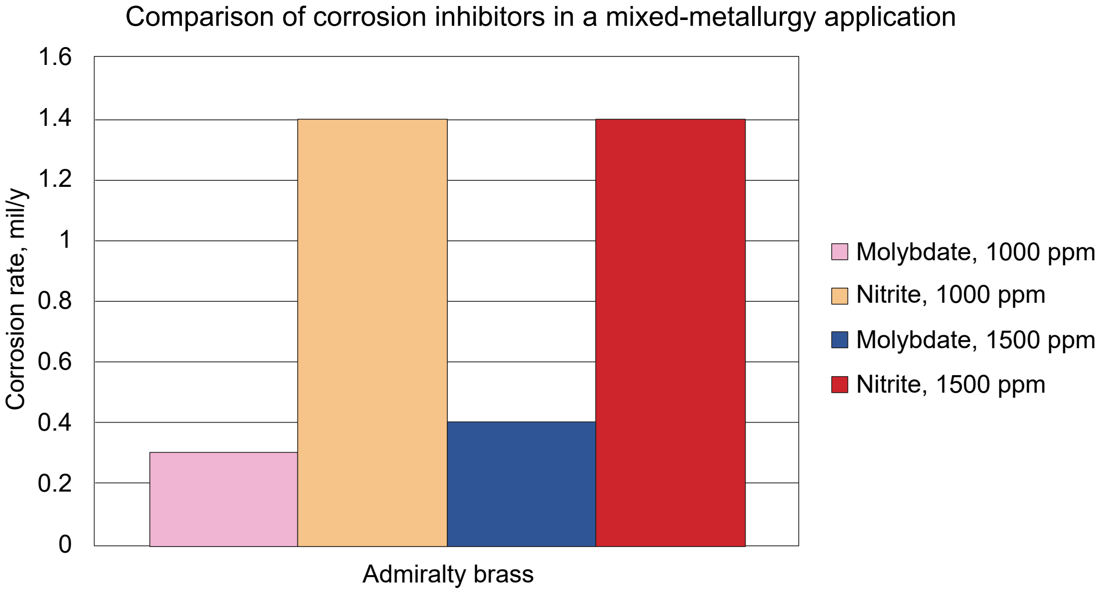


Figure 4 – Molybdate and Nitrite Comparison: Brass Systems



In cooling systems, a form of corrosion called **selective leaching** may also occur. When this happens, one particular metal is preferentially attacked. In cooling systems, this is usually zinc; hence, this type of corrosion is also called **dezincification**. Selective leaching tends to occur at low pH values (< 6), and high free chlorine residuals (> 1 ppm).

When corrosion is severe, it leads to tube failure. Apart from the time the heat exchanger is out of service, there are material costs associated with replacing failed tubes. Table 1 shows estimated material costs for chiller re-tubing or replacement. A quick review shows that re-tubing runs about 25 to 30% of a new chiller.

Table 1 – Approximate Costs to Replace or Re-Tube Chillers (CAD, 2017)

Capacity (Tonnes)	Chiller Replacement	Chiller Re-Tubing
850	$97 500	$25 000
1750	$160 000	$45 000
2650	$220 000	$65 000

Fouling

Solids fouling is a big problem for heat exchangers, especially if there is any of the following:

- Fluid leaking into the system
- Corrosion
- Scaling
- Biological growth

Usually, problems are avoided by using strainers or filters. These need to be cleaned or replaced about once a year. Often a bypass line with a filter is used (a **slipstream filter**). A small amount of the circulated water bypasses through the filter on a continuous basis. This helps to maintain a low level of suspended impurities that lead to fouling.

Scaling

Scaling can be an issue in closed cooling systems. However, since system losses and raw water make-up are minimal, scale forming salts are introduced only in very small amounts. Lower temperature systems have little risk of scale formation.

However, in cooling systems that operate at higher temperatures (such as those used for internal combustion engines), scaling may occur. At these higher temperatures, any impurities introduced with make-up water can eventually become a problem. In these cases, water added to the system should be demineralized, distilled, or reverse osmosis.

For all closed loop systems, make-up water should never exceed 0.1% of the system capacity per day, or 2% of the system capacity per month.

Biological Fouling

Biological fouling (also called filming) is possible if leaks occur. Biofilms decrease heat transfer efficiency, and can promote corrosion. If biological fouling is a problem, biocides are added to remove the film. **Dispersants** are also added to keep the dead biological matter in suspension until it is removed by blow off.

Freezing

As water transfers heat, its temperature drops. If the refrigerated medium is below 0°C, there is a risk of freezing. As water freezes, it expands about 9%. This is likely to rupture or damage pipes, tubes, HVAC coils, and mechanical equipment.

Chillers are equipped with **freeze stats** so that if the refrigerant temperature gets too low, the chiller trips off. This protects the chiller evaporator coil from freezing damage. Refrigeration systems that used closed cooling loops may be filled with a brine solution of water and calcium chloride or glycol. HVAC cooling coils that are filled year-round often use glycol solutions to prevent freeze-up.

Glycol solutions are discussed later in this chapter.

HEATING SYSTEMS

Hot water closed-loop systems are very similar to those used for chilled water. They have the same risk of scale formation, deposition, fouling, and corrosion as do closed cooling systems. However, because they operate at higher temperatures, these risks are all magnified. Scale deposition and corrosion processes are far more aggressive as temperatures increase. The treatment and monitoring of these conditions, though, is similar.

Hot water heating systems may also be susceptible to freezing. Vestibule heaters, where doors are opened regularly, are susceptible to winter freeze-up. Air handling unit-heating coils may also freeze if the outside air is below 0°C, and if the air handler freeze stat does not function correctly. For additional security, many heating systems are also filled with glycol and water solutions.

OBJECTIVE 2

Describe the use of sacrificial anodes, and measurement techniques to determine corrosion.

GALVANIC CORROSION

Galvanic corrosion occurs when two dissimilar metals contact each other, and are surrounded by an **electrolyte** (an aqueous solution). Each metal has a characteristic **electrochemical potential**. When two metals contact each other, the difference of electrochemical potential causes electrons to flow from the more negative metal (the **anode**) to the more positive metal (the **cathode**). When the anode loses electrons, soluble metal ions are left behind. These enter solution with the electrolyte. This causes the anodic metal to waste away.

Galvanic corrosion can even occur when there is only one type of metal present. For instance, a pipe can have galvanic corrosion even though it is constructed of one material. Surface imperfections, different crystal sizes, or crystal misalignment creates enough electrochemical potential to cause galvanic corrosion. Even a scratch or a dent can cause one location to be more anodic. Anodic locations corrode. In **stress corrosion cracking**, the area under stress (usually a bend or dent) is anodic to the rest of the metal, and corrosion occurs.

Scientists and engineers have determined the electrochemical potentials for different metals. The result is known as the **electromotive series** (see Table 2). This table lists the electrochemical potential of various metals, in descending order. When comparing two metals, it shows the voltage difference between them when combined in a galvanic cell.

For example, consider the electrical potential between copper and zinc. Copper has an electrochemical potential of +0.52 volts. Zinc has an electrochemical potential of –0.76 volts. When coupled in a galvanic cell, the potential difference is 1.28 volts. This will cause the zinc to corrode. The greater the potential difference between two metals, the greater the rate of corrosion.

The metals listed at the top of Table 2 are the most cathodic. These **noble metals** do not readily corrode. Rather, they receive electrons from anodic metals.

Table 2 – Electrode Potential of Various Metals

Metal	Electrochemical Potential (Volts)
Gold	+1.5
Silver	+0.8
Copper	+0.52
Hydrogen	0.00
Lead	–0.13
Tin	–0.14
Nickel	–0.25
Iron	–0.41
Chromium	–0.74
Zinc	–0.76
Aluminum	–1.66
Magnesium	–2.37
Lithium	–3.04

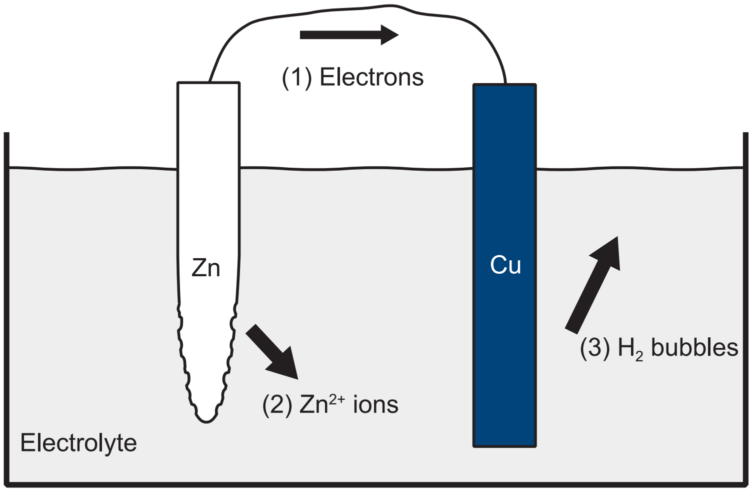
The corrosion process in a zinc-copper galvanic cell is shown in Figure 5. The copper (Cu) is more noble and acts as the cathode. The zinc (Zn) acts as an anode. The electrolyte is water. Note that in water, a certain proportion of H_2O dissociates into H^+ and OH^- ions. These ions are very important to the galvanic corrosion process.

Electrons (1) travel from the anode to the cathode. Though this is shown in an external circuit, the electrons actually flow through the metals where they contact.

The flow of electrons from the zinc creates Zn^{2+} cations. These are soluble, and enter solution with the electrolyte (2).

The electrons combine at the surface of the cathode with H^+ ions that are in the electrolyte. This forms bubbles of H_2 gas (3). The metal ions combine with OH^- ions at the surface of the anode, and precipitate as zinc hydroxide ($Zn(OH)_2$).

Figure 5 – Galvanic Corrosion in a Copper-Zinc System



Of course, most materials of construction are not made of pure elements. Engineers must review the potential for galvanic corrosion when joining different alloys.

To minimize galvanic corrosion, the operator should be aware of what materials have been used in the system and, when necessary, only use other materials of similar electrochemical potential. Dissimilar metals may be used, but only if they are electrically insulated from each other. As a rule of thumb, the electrochemical potential difference between two materials should be less than 0.15 V for most industrial applications.

Another way to prevent galvanic corrosion is to couple an anodic metal piece to the cathodic materials that are to be protected. These are called **sacrificial anodes**.

Copper and iron combinations are quite common. These two materials form a galvanic cell with an electrical potential of 0.96 volts. In this situation, the iron is anodic and will corrode.

Zinc is anodic to both copper and iron. If a piece of zinc is mechanically and electrically bonded to the copper and iron components, and immersed in the same electrolyte, the zinc will corrode. The iron and copper will remain intact. The zinc piece, then, is a sacrificial anode. Because they corrode, sacrificial anodes require regular replacement.

Hot water tanks commonly use sacrificial anodes of magnesium or aluminum. In heat exchangers, the sacrificial anodes are bolted directly to the steel in areas where corrosion is most likely.

ADDRESSING CLOSED SYSTEM CORROSION

There are several tools available for monitoring closed loop corrosion. Corrosion or system corrosiveness can be monitored with the use of expensive and sophisticated instruments. In plants that do not have such equipment, visual inspection and other checks may be done to determine active corrosion sites and places where corrosion could potentially occur. This includes:

a) Check pipes and piping connections for leaks. These could indicate corroded metal, especially if corrosion products are evident.

b) Identify piping connections between dissimilar metals (such as galvanized and copper pipe).

c) Remove and examine corrosion coupons on a regular basis.

d) Inspect the integrity of sacrificial anodes.

e) Perform tests on closed system water to determine:
   - pH
   - Oxygen scavenger residual
   - Conductivity
   - Corrosion inhibitor residual

f) Check for pressure drops and flow rates across heat exchangers and strainers. These can show whether corrosion is occurring. Increasing pressure drops may indicate that deposits from corrosion processes are accumulating.

g) Use **borescopes** to inspect the inside of tubes and shells during shutdowns for signs of corrosion or deposition.

The following activities can prevent closed system corrosion:

a) Replace dissimilar piping with piping of similar materials.

b) If piping connections between dissimilar metals are unavoidable, install special **dielectric** pipe fittings.

c) Install sacrificial anodes. Replace anodes on a regular basis.

d) Add corrosion inhibiter and oxygen scavenger according to the plant water treatment recommendations.

OBJECTIVE 3

Describe glycol system testing requirements.

USE OF GLYCOL IN CLOSED LOOP SYSTEMS

To prevent freezing damage, glycol may be added to closed system heating or cooling water. Glycol is a colourless and odorless substance used mostly for manufacturing plastics and antifreeze. The two main types used are **ethylene glycol** [$(CH_2OH)_2$] and **propylene glycol** [$C_3H_8O_2$]. Both taste sweet; however, ethylene glycol is toxic and propylene glycol is not. Therefore, where contact with food products may occur, propylene glycol must be used.

Automotive glycol should not be used in industrial closed loop systems, because it has a shorter life span and may contain silicates (which create deposition problems). Also, ethylene glycol and propylene glycol should not be used together. Doing so can cause inhibitors to precipitate. As well, the combination can gel.

Glycol reacts with oxygen to form organic acids that will increase corrosion. Therefore, glycol heat transfer fluids are factory-blended with corrosion inhibitors. Manufacturers produce test kits to check for the correct amount of inhibitor. Many glycol suppliers also provide inhibitor analysis, often free of charge.

The pH of a system is a good indicator of whether the glycol contains adequate inhibitor. Most glycol systems will have a pH between 9 and 9.5. If the pH drops to below 8, it is likely that inhibitor has been consumed to neutralize acid formation. If the pH drops below 7, the system likely requires a full internal cleaning, and replacement of the glycol solution.

Propylene and ethylene glycols are different from water, and different from each other, in the following ways:

- Glycols are more viscous than water; therefore, they require more pumping power. Of the two glycols, propylene requires the most pumping power, because it is the most viscous.
- Propylene glycol must be mixed at a higher concentration to provide the same freeze protection as ethylene glycol (see Table 3).
- Both propylene and ethylene glycol have significantly lower specific heats than water. Of the two glycols, propylene has the lowest specific heat.
- Propylene glycol is more expensive than ethylene glycol. However, if toxicity is a concern, only propylene can be used.
- It is more costly to use glycol than water, and more costly to use propylene glycol than ethylene glycol.

Table 3 shows the recommended glycol concentrations to achieve the desired freeze protection.

Table 3 – Recommended Glycol Concentrations (by Volume)

Temperature Range	Ethylene Glycol	Propylene Glycol
–35 to –40°C	45 – 55%	50 – 54%
–15 to –20°C	30 – 35%	35 – 40%

In all cases, glycol concentrations should never be less than 20%. Low glycol concentrations create a nutrient source that promotes significant biological fouling.

Occasionally, closed loop systems originally designed to circulate water are converted to glycol systems. Glycol systems require less monitoring, and are a better option for remote sites. Also, glycol is relatively trouble free when inhibitor is used properly. Systems may last upwards of 12 years with minimal attention.

However, glycol solutions – at the required concentrations for freeze protection – transfer less than half the heat of water. Converting a water system to a glycol system reduces its heat transfer capacity by over 50%. As well, glycol systems are more expensive to fill, and require greater pumping power.

Automatic municipal water make-up should not be used in glycol systems. It dilutes the mixture and reduces its freeze point. As well, municipal water introduces biological contaminants, dissolved corrosive gases, and scale forming compounds that negatively affect the glycol and inhibitor. Make-up should be through a special tank and pump system that is filled with glycol and demineralized water to the proper concentration.

Glycol manufacturers recommend that only demineralized, distilled, or deionized water be mixed with glycol. However, there is some tolerance of impurities. Table 4 shows the maximum levels of dilution water impurities that glycol manufacturers permit.

Table 4 – Dilution Water Requirements for Glycol System

Impurity	Maximum level
Chlorides	25 ppm
Sulfates	25 ppm
Total Hardness as $CaCO_3$	100 ppm

Glycol should not be used directly in a boiler or heater system. Glycol breaks down when exposed to the high heat transfer surface temperatures found in boilers. A heat exchanger should be used between the boiler and the closed loop system.

OBJECTIVE 4

Discuss the monitoring tools, procedures, and tests used in recirculating water systems.

MONITORING AND TESTING

Many of the same tests that operators perform on boilers and cooling towers are used in closed loop systems.

The pH tests indicate if systems are becoming acidic, especially when glycols are used. Falling pH means that inhibitor is being consumed, and needs to be replenished. The pH tests are important and should be done on a monthly basis for all systems.

Many water specialists recommend that heating and cooling systems be initially dosed with sodium sulfite to scavenge oxygen. In systems treated with sulfite, residuals should be checked on a monthly basis. If a major leak has occurred, and considerable make-up has been added, immediately check the sulfite levels, and feed additional chemical to the system to restore the proper concentration.

Systems that contain glycol should be tested annually for freeze point and inhibitor.

Corrosion coupons should be removed and tested every one to three months.

Conductivity measurements allow operators to keep track of dissolved solids. These may result from corrosion or excessive make-up. Conductivity tests can be done on a monthly basis as well.

Make-up water usage should be monitored. Meters should be installed on the make-up water line. Make-up water should be minimal. High make-up means there are leaks that require repair. High make-up also indicates a need for additional water treatment chemical. Make-up should be checked at least monthly.

Operators play the most important role in closed system monitoring. Frequent visual inspections for signs of leakage or corrosion is essential. Any leaks, loose insulation, or visible corrosion by-products should be addressed immediately.

CHAPTER SUMMARY

Scale formation, corrosion, and biological fouling do not only affect boilers, cooling towers, and condensers. Closed loop heat transfer systems are also affected. However, because closed loop systems operate at relatively low temperatures, scale deposition and corrosion may proceed more slowly. Chemical treatment has been effective at treating scale, corrosion, and biological growth.

The problems encountered in closed systems may be more a factor of system metallurgy rather than water chemistry. Dissimilar metals found in closed loop systems create galvanic corrosion cells. This can be addressed with dielectric couplings and sacrificial anodes.

Like other plant systems, closed loops require freeze protection as well. Glycol solutions can be used to prevent freezing; however, system capacity will be reduced. Glycol solutions must be inhibited, because uninhibited glycol is just as corrosive - or even more corrosive - than water.

Conductivity, pH, inhibitor concentration, freeze point, and oxygen scavenger tests are performed regularly to ensure the closed loop system is not scaling, corroding, or fouling.

UNIT SUMMARY

The Water Treatment unit outlined, discussed, and illustrated water treatment principles, methods, testing, and equipment. The following systems, and their unique water treatment needs, were covered:

- External water treatment
- Internal water treatment
- Condensate treatment
- Cooling tower and condenser water treatment
- Recirculating closed-loop systems

This unit emphasized the importance of having high quality water within all plant thermal fluid systems. It also looked at how the proper treatment, or lack thereof, can affect both equipment and system integrity.

A self-assessment tool is available on MyPower LMS. Login using the unique user ID and password found on the inside front cover of Unit 1.

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UNIT B-6

KNOWLEDGE EXERCISES AND UNIT GLOSSARY

KNOWLEDGE EXERCISES – CHAPTER 1

Name: ______________________ Date: ______________________

Instructor: ______________________ Course: ______________________

Objective 1

1. What are the main types of impurities in water that concern Power Engineers?

2. Which problems resulting from impurities occur in the boiler?

3. What effects do suspended solids have on boilers?

4. What effects do dissolved solids have on boilers?

5. What effects do dissolved gases have on boilers?

Objective 2

6. Which one has harder water and why: Vancouver or Calgary?

7. What is coagulation?

Chapter 1 (Cont.)

8. What is flocculation?

9. What are the ASME guidelines for total hardness for low-pressure boilers?

Objective 3

10. What does a clarifier do?

11. What needs to be done to address a plugged pressure filter?

12. What occurs when a filter-aid tubular filter is plugged and no longer working?

Objective 4

13. How does a lime-soda softener work?

14. What needs to be done to a zeolite bed once it stops removing hardness?

Chapter 1 (Cont.)

15. Describe the demineralizer process.

Objective 5

16. Under what conditions does a deaerator work?

17. What does a deaerator remove?

18. What is the purpose of a condenser in a deaerator?

KNOWLEDGE EXERCISES – CHAPTER 2

Name: ______________________ Date: ______________________

Instructor: ______________________ Course: ______________________

Objective 1

1. What are the six main types of problems caused by boiler water impurities?

2. What is meant when a boiler is said to be priming?

3. What causes pitting corrosion?

4. What types of amines are used in a boiler and why?

5. Why is molybdate added to a boiler?

Chapter 2 (Cont.)

Objective 2

6. What negative results can occur from an inefficiently designed, or poorly operated chemical feed system?

7. Chemical feed pumps supply ________________ volumes of fluid at ____________ pressure.

8. Describe how to add chemical to a closed system, using a pot feeder.

Objective 3

9. Why is it important to keep samples away from air when testing for sulfite?

10. What documents must be read before handling hazardous chemicals?

Chapter 2 (Cont.)

11. What are the typical safety measures when testing water samples?

12. How many types of alkalinity are there in boiler water, and what species causes them?

13. Why are sulfites found in boiler water?

14. Why are phosphates found in boiler water?

15. What is the preferred pH range for a boiler?

16. Name the titrant used when testing for:
    a) Hardness
    b) Alkalinity
    c) Sulfite

Chapter 2 (Cont.)

17. A boiler has an M-alkalinity that is greater than the prescribed control range. What is the appropriate operator response?

KNOWLEDGE EXERCISES – CHAPTER 3

Name: ______________________________ Date: ________________________________

Instructor: ___________________________ Course: ______________________________

Objective 1

1. Explain why condensate should be reused.

2. List the two main reasons that condensate may require treatment.

3. Name four common contaminants found in steam system condensate.

4. How do neutralizing amines work?

5. What is the main problem if neutralizing amines are overfed?

Chapter 3 (Cont.)

6. Where are filming amines injected and why?

Objective 2

7. What are five precautions to take when grabbing a condensate sample?

8. What are corrosion coupons?

9. What is a fluorometer?

KNOWLEDGE EXERCISES – CHAPTER 4

Name: ______________________________ Date: ________________________________

Instructor: ___________________________ Course: ______________________________

Objective 1

1. Name five major problems with cooling tower water.

2. What are the sources of cooling water contaminants?

3. What is Legionella?

Objective 2

4. What is soft sludge?

5. What is meant by cycles of concentration?

Chapter 4 (Cont.)

6. A make-up water pump circulates 19 000 L/min of make-up water to a cooling tower. The tower operates between 4.5 and 5 cycles of concentration. What is the range of acceptable blowdown rates for this tower?

7. What are chemical inhibitors, and how do they work?

Objective 3

8. What activities does an operator perform around cooling tower water?

9. What are biological dip slides, and what are they used for?

10. A cooling water dip slide test shows 10^6 cfu/ml. What is the appropriate operator response?

KNOWLEDGE EXERCISES – CHAPTER 5

Name: ______________________________ Date: ________________________________

Instructor: ___________________________ Course: ______________________________

Objective 1

1. What effect does temperature have on corrosion?

2. What is a closed loop system?

3. For all closed loop systems, make-up water should never exceed _________ of the system capacity per day, or ________ of the system capacity per month.

Objective 2

4. What three conditions must be present for galvanic corrosion to occur?

5. What is a sacrificial anode?

6. What is the electrochemical potential between copper and magnesium?

Chapter 5 (Cont.)

Objective 3

7. Why is glycol added to closed loop water?

8. Why must inhibitors be used with glycol systems?

9. What is the concern when glycol concentrations are kept at or below 20%?

Objective 4

10. Name five tests that may be performed regularly on closed system fluids.

11. Why is it important to monitor closed loop system make-up?

12. An inhibited glycol system shows a falling pH over the period of three months. What is the concern?

UNIT B-6 GLOSSARY

Term	Definition
Acidity	In water: the excess of hydrogen ions (H+) over hydroxide ions (OH–) that occurs where the pH is less than 7.
Adsorb	To hold a film of gas or liquid molecules of one material onto the surface of another material.
Agglomeration	The coming together of small, scattered particles into larger, heavier particles, called floc, which are then able to settle easier and faster out of a liquid. See "Floc."
Alginate	Plant-sourced compounds that, when added to boiler water, combine with precipitated scale-forming compounds. This keeps them fluidized and non-adherent.
Alkalinity	The capacity of water to neutralize acids. This capacity is caused by the water's content of carbonate, bicarbonate, hydroxide, and occasionally borate, silicate, and phosphate.
Alum	A common name for any form of aluminum sulfate. Alum is used in water treatment clarifiers as a flocculant.
Amine	A broad category of ammonia-derived organic compound that has various industrial uses. Power plant use ranges from oxygen scavenging to corrosion prevention.
Anion	An atom with more electrons than protons and, hence, is negatively charged.
Anode	The positive terminal of an electrolytic cell.
Anodic inhibitor	A chemical additive that forms a protective layer of oxide film on the surface of metal, and provides resistance to corrosion by altering the anodic reactions.
Avian waste	Biological products deposited by birds, including feathers and feces.
Bicarbonate	Any salt containing the anion HCO_3^-.
Biofilm	A thin, slimy, adherent film of bacteria.
Biological fouling	The result of abundant growth of algae, fungi, and bacteria on cooling tower surfaces.
Borescope	A fibre optic instrument used for the visual inspection of narrow passages.
Burette	An apparatus used to accurately measure the volume of reagent used during a titration.
Carbonate	Any salt containing the anion CO_3^{2-}.
Carryover	The entrainment of water droplets in the steam leaving the boiler drum.
Cathode	The negative terminal of an electrolytic cell.
Cathodic inhibitor	A chemical additive that provides surface protection by either slowing the cathodic reaction, or selectively precipitating on cathodic areas, to limit the diffusion of reducing species to the surface.
Cation	An atom with less electrons than protons and, hence, is positively charged.
Caustic cracking	Intercrystalline cracking of boiler carbon steel caused by a corrosion reaction in the presence of caustic along the grain boundaries within the metal.
Caustic embrittlement	The intercrystalline cracking of steel caused by the presence of free NaOH, stress, boiler water leakage, and concentration of NaOH.

Term	Definition
Caustic gouging	Caustic corrosion that occurs under accumulated scale deposits.
Caustic soda	A very high pH (basic) compound, it has various uses in power plants. Also called sodium hydroxide.
Cellulose	An insoluble organic substance that is the main constituent of plant cell walls. Cellulose is used in the production of pulp.
CFU	See *colony forming unit (CFU)*.
Chelants	Chemicals designed to bind to positively charged soluble metal ions, most commonly calcium and magnesium. They reduce scale deposits or remove pre-existing scale.
Clarifier	A settling tank used to remove sediment from water through sedimentation, coagulation, or flocculation.
Coagulation	The use of chemicals that cause suspended matter to join together into larger particles. This makes it easier to remove the suspended matter from the liquid by settling, skimming, draining, or filtering.
Colony forming unit (CFU)	A unit used to estimate the number of live bacteria in a sample.
Conductivity-based blowdown	Blowdown triggered by a change in the conductivity of cooling tower water.
Cooling tower	A device that rejects waste heat from water by evaporating a portion of the water, thus cooling the remainder for reuse as industrial coolant.
Corrosion	The destruction of a metal by chemical or electrochemical reaction with its environment.
Corrosion coupon	A material specimen of known mass used in tests to determine corrosion rates.
Cycles of concentration	In an evaporative system, the ratio of concentrated dissolved solids in the evaporating water, to the dissolved solids in the source water.
Cycling control	The maintenance of the appropriate ratio of dissolved solids in the circulating water, to the dissolved solids in the make-up feedwater.
Deaeration	Removal of oxygen and other non-condensable gases.
Deaerator	A component used for removing oxygen and other corrosive non-condensable gases that may be dissolved in boiler feed water.
DEHA	An abbreviation for diethylhydroxylamine. DEHA is used as a boiler water oxygen scavenger.
Delignification	The removal of lignin from woody tissue.
Dezincification	A form of corrosion that results in the weakening of copper alloys, due to the dissolution of zinc.
Dielectric	A material that does not conduct electric current, but permits the passage of lines of force associated with an electromagnetic field.
Differential microbial analysis (DMA)	A set of laboratory tests that identifies the microorganisms found in cooling water systems.
Dispersant	A polymer that, when in solution, improves the separation of colloidal particles, in order to reduce clumping and settling.
Dissolved gases	Gases, such as oxygen and carbon dioxide, which may be in solution in water.
Dissolved solid	A solid impurity in solution with water. In boilers, calcium and magnesium salts are scale-forming dissolved solids.
DMA	See *differential microbial analysis (DMA).*

Term	Definition
EDTA	An abbreviation for ethylenediaminetetraacetic acid. EDTA is used as both a boiler water chelant, and as a reagent for titrating water hardness samples.
Electrochemical potential	The difference in voltage between two dissimilar metals, connected through an external conducting circuit, and placed in a conducting solution so that electrochemical reactions occur.
Electrolyte	A liquid or paste that conducts electricity as a result of the presence of positive or negative ions.
Electromotive series	An arrangement of chemicals according to their ability to gain or lose electrons, measured with reference to a hydrogen electrode having an electrical potential of zero.
Endpoint	The point that a colour change occurs during titration.
Ethylene glycol	A moderately toxic, hygroscopic, viscous liquid made from ethylene mixed with water in various proportions, and used as an antifreeze or heat transfer fluid.
Filming amine	An amine that protects against oxygen and carbon dioxide corrosion by replacing the loose oxide scale on metal surfaces with a very thin amine film barrier.
Flocculation	The gathering together of small particles to form larger particles.
Fluorometer	An analytical device for identifying the presence and the amount of specific molecules in a medium.
Foaming	The continuous formation of bubbles with sufficiently high surface tension, so they remain as bubbles above the disengaging surface. This interferes with the natural steam disengagement process and can result in priming.
Freeze stat	A temperature sensitive switch that protects heat exchangers from damage due to freezing.
Galvanic corrosion	An electrochemical process in which one metal corrodes preferentially when it is in electrical contact with another, in the presence of an electrolyte.
Glycol	A hygroscopic, viscous liquid made from ethylene or propylene, mixed with water in various proportions, and used as an antifreeze or heat transfer fluid.
Ion exchange resin	Insoluble polystyrene materials containing loosely held cations or anions that exchange with other cations or anions.
Legionella bacteria	A type of bacterium found naturally in freshwater environments, such as lakes and streams. It has been linked to serious lung infections in building systems.
Lignin	The compound that binds cellulose fibres in wood.
Lignin (water treatment)	Organic material, sourced from wood products. Lignins prevent or reduce boiler deposits, and modify the condition of boiler sludge so that they can be more conveniently eliminated by blowoff.
Magnetite	An iron oxide that forms in an operating boiler. It makes boiler waterside surfaces corrosion resistant (passive).
Make-up proportional blowdown	Blowdown triggered directly by the amount of make-up water added to a cooling tower.
Methyl alkalinity	A test performed to measure total alkalinity of boiler water.
Neutralizing amine	An amine used to neutralize the acid generated by the dissolution of carbon dioxide, or other acidic process contaminants in condensate.
Noble metal	A cathodic metal that is resistant to chemical action, corrosion, and acidic attack.

Term	Definition
pH	Unit of measure of the acid or alkaline condition of a substance.
Phenolphthalein	A solution which changes from clear to red in solutions with a pH of 8.3 or greater.
Phenolphthalein alkalinity	A measure of the hydroxide ions plus one-half of the normal carbonate ions in aqueous suspension. Measured by the amount of sulfuric acid needed to bring the water to a pH value of 8.3, as indicated by a change in colour of phenolphthalein.
Pontiac fever	A mild flu-like illness caused by exposure to Legionella bacteria.
Propylene glycol	A non-toxic, hygroscopic, viscous liquid made from propylene, mixed with water in various proportions, and used as an antifreeze or heat transfer fluid.
Sacrificial anode	A metal with a negative electrochemical potential that, when electrically coupled with other metals, corrodes preferentially.
Scale	A deposit that forms on tubes, reducing heat transfer efficiency.
Selective leaching	A form of corrosion in which certain constituents of a solid metal solution corrodes preferentially. Dezincification is a form of selective leaching.
Slipstream filter	A cartridge filter installed in parallel with a closed loop system that continually filters a portion of the system fluid.
Sludge	Accumulated residue resulting from impurities in water as it boils.
Sodium zeolite	A natural or synthetic material used in ion-exchange water softeners, which is regenerated with sodium chloride salt.
Softener	The process of elimination or reduction of calcium and magnesium in water (hardness).
Steam blanketing	The laminar flow of steam and water in a boiler tube, whereby a steam film separates the heat transfer surface from the boiling water.
Stress corrosion cracking	A form of progressive intergranular fracture caused by a combination of stress, elevated temperature, and a corrosive environment.
Suspended solid	A mixture of fine non-settling particles in a solution that may be removed by filtering.
Tannin	Organic material, sourced from wood products. Tannins, like lignins, prevent or reduce boiler deposits, and modify the condition of boiler sludge, so that they can be more conveniently eliminated by blowoff.
Titrate	The process of adding a chemical to another solution, drop by drop, until an endpoint is reached.
Titration	A test method used to determine the dissolved substance concentration in a sample.
Turbidity	The measurement of the cloudiness of water due to the entrainment of suspended solids or other particles.
Zeolite	A type of resin used in an ion exchange process.

Additional Workspace

Additional Workspace

Additional Workspace

Additional Workspace