Module 234-6

THE CONDENSATE, THE BOILER FEED, AND THEIR AUXILIARY SYSTEMS

OBJECTIVES:

After completing this module you will be able to:

6.1 State:

a) The secondary function of the main condensate extraction pumps (CEPs); ⇔ *Page 6*

b) Two secondary functions of the auxiliary CEP and the unit operating state when each of them is performed; ⇔ *Pages 6-7*

c) The secondary function of the main boiler feed pumps (BFPs) when used in the recirculation mode; ⇔ *Page 7*

d) Two reasons why use of the main BFPs for prewarming condensate in the deaerator storage tank should be minimized; ⇔ *Page 7*

e) The secondary function of the auxiliary BFP and the unit operating state when it is required. ⇔ *Page 7*

6.2 a) State the adverse consequences/operating concerns caused by improper hotwell level: ⇔ *Pages 8-9*

    i) Too low a level (2);

    ii) Too high a level (1).

b) List: ⇔ *Pages 9-10*

    i) Three automatic actions initiated by too low a hotwell level;

    ii) Two automatic actions initiated by too high a hotwell level.

c) List three causes of each of the following hotwell level upsets: ⇔ *Pages 10-11*

    i) Too high a level;

    ii) Too low a level.

d) State the operating concern caused by a very low condensate reject (storage) tank level. ⇔ *Page 11*

6.3   a)   List the typical heat sources available to:

    i)   LP feedheaters (2);

    ii)   Deaerator and storage tank (5);

    iii)   HP feedheaters (2).

    b)   State when each heat source is used.

6.4   Explain the self-regulating feature of the extraction steam flow to the feedheaters.

6.5   a)   Describe two adverse consequences/operating concerns caused by continued feedheater operation if its drains level is:

    i)   Too high;

    ii)   Too low.

    b)   List the actions in response to the following feedheater drains level upsets:

    i)   Too high a level (8);

    ii)   Too low a level (2),

    and explain the purpose of each action.

    c)   List the causes of each of the following feedheater drains level upsets:

    i)   Too high a level (3);

    ii)   Too low a level (2).

6.6   a)   i)   List three operating upsets during which some or all of the check valves in the extraction steam lines would be actuated to close.

    ii)   State the purpose of this action.

    b)   Explain two operational reasons why these valves are equipped with actuators.

6.7   State:

    a)   One cause of insufficient feedheater shell venting during normal unit operation;

    b)   Two main indications of this upset;

    c)   The corrective action the operator can take to rectify the problem.

6.8   Describe how the flow of heating steam to the deaerator (DA) is regulated during:

   a)   High power operation;

   b)   Startup and low power operation;

   c)   Poison prevent operation.

6.9   a)   i)   Explain how a rapid drop in DA pressure can cause steam hammer in the feedheating system.

      ii)   State the major cause of a rapid drop in DA pressure and list three operating upsets during which it can occur.

   b)   i)   Explain how abnormally high DA pressure can occur.

      ii)   Explain how this pressure can lead to steam hammer in the feedheating system.

6.10   a)   State three adverse consequences/operating concerns caused by each of the following upsets:

      i)   DA storage tank level too high;

      ii)   DA storage tank level too low.

   b)   Describe how DA storage tank level is controlled during:

      i)   Unit startup and low power operation;

      ii)   High power operation.

   c)   List the actions in response to each of the following upsets:

      i)   DA storage tank level too high (4);

      ii)   DA storage tank level too low (5).

   d)   List the causes of each of the following DA storage tank level upsets:

      i)   Too high (1);

      ii)   Too low (3).

6.11   State and explain how:

   a)   Unit Loading;

   b)   Unit Unloading,

   affect:

      i)   Boiler level and operation of the boiler level control valves (LCVs);

ii) DA storage tank level and operation of DA storage tank LCVs;

iii) Hotwell level and operation of the makeup water valves or the condensate reject valve;

iv) The number of operating CEPs and BFPs;

v) Extraction steam flows and feedheater drains flows;

vi) Feedwater temperature at the boiler preheater inlet.

6.12 a) State two adverse consequences/operating concerns caused by exceeding a limit on the maximum temperature difference (ΔT) between the boiler preheater and the entering feedwater.

b) i) List three unit operating states during which this limit might be exceeded.

ii) Explain why this can occur.

c) Explain two general operator actions that can be taken to minimize the possibility of exceeding the ΔT limit.

d) Explain two general operator actions that can be taken to return the ΔT to an acceptable value if the ΔT limit has been exceeded.

6.13 a) Explain how operating with a bank of feedheaters valved out affects:

i) Extraction steam and drains flows in the feedheaters;

ii) Feedwater temperature at the boiler preheater inlet;

iii) Thermal efficiency of the unit;

iv) Turbine generator output (consider the reactor leading and lagging modes of operation).

b) Explain three reasons why it may be necessary to derate the unit if a significant number of feedheaters are out of service.

6.14 a) State a typical interunit feedwater tie (IUFWT) flow capacity as a percentage of the full power feedwater flow of a single unit.

b) State the accident that would require the IUFWT to operate.

c) Describe how the IUFWT would operate to alleviate the accident.

6.15 a) State the major action the operator must take if during normal operation both the auxiliary boiler feed pump and the IUFWT are unavailable and the limit on their sustained unavailability has been approached.

b) Explain the reason why this action must be taken.

6.16   a)   Name and describe two systems that can be used to provide water to the boiler in the event of total loss of all other sources of treated feedwater.

     b)   State:

       i)   The basic operating condition that must exist before either of these two systems can feed water to the boiler;

       ii) Two operational problems that make these systems the least preferable source of boiler feedwater.

6.17   Describe five causes (other than DA pressure control problems)* of steam or water hammer in the condensate, the boiler feed, and their auxiliary systems.

* Obj. 6.9 covers this cause of steam/water hammer.

* * *

INSTRUCTIONAL TEXT

INTRODUCTION

In the previous turbine courses you have learned about the structure of the condensate, the boiler feed, and their auxiliary systems*. You also familiarized yourself with the major components of these systems, their principles of operation and major functions. Based on this entry level knowledge, the following topics are discussed in this module:

* For simplicity, a set of all these systems together is often referred to as *the feedheating system.*

– Secondary functions of the major pumps in the feedheating system;
– Hotwell level control;
– Assorted operational aspects associated with feedheaters;
– Deaerator pressure and level control;
– Major changes in the feedheating system during unit loading and unloading;
– Excessive thermal stresses at the boiler preheater inlet;
– Operation with many feedheaters out of service;
– Alternate sources of feedwater;
– Causes of steam or water hammer in the feedheating system.

Similarly to the preceding modules, a simplified pullout flowsheet of the system being discussed is provided (on page 69) for easy reference. Due to numerous station specific differences, the number and/or location of some of the equipment shown in the flowsheet may differ from those in your station. For simplicity, the flowsheet is split into two parts:

– The condensate system (called, in some stations, *the main condensate system* or *the LP feedwater system*), and

— The boiler feed system (alternatively called *the HP feedwater system* or *the boiler feedwater system*).

Major auxiliary systems such as the extraction steam system, the feedheater drains system and the makeup water system are shown in this flowsheet, too.

The last pullout page of this module shows a simplified feedheater, and a deaerator and its storage tank assembly. You are advised to refer to these diagrams while studying the relevant sections of this module.

SECONDARY FUNCTIONS OF MAJOR PUMPS IN THE FEEDHEATING SYSTEM

Condensate extraction pumps (CEPs)

Obj. 6.1 a) ⇔

You will recall from previous turbine courses that the main CEPs supply condensate (also called *LP feedwater*) from three condenser hotwells through the LP feedheaters up to the deaerator (DA). The **secondary function of the main CEPs** is to supply cool condensate required by auxiliary systems and equipment, such as the boiler feed pump gland injection system, the LP turbine exhaust cooling system, the gland exhaust condenser, and the air ejector condenser and the condenser cooling sprays (if installed). While the condensate flow required by these systems is small in comparison with the main flow, failure to meet the demand may result in equipment damage and serious operational upsets, including a forced unit outage.

* Its capacity is about 5% of the full power flow.

As to the **auxiliary CEP**, you will recall that this small pump* supplies condensate from the hotwells directly (ie. bypassing the LP feedheaters) to the DA. This allows us to maintain long-term reactor cooling (at the decay heat level) via the boilers when the main CEPs are shut down or otherwise unavailable. The loss of CEPs can be caused by some operating problems, such as a loss of class IV power or a pipe break in the condensate system.

Obj. 6.1 b) ⇔

In addition, the auxiliary CEP has two **secondary functions**:

1. **To fill up the condensate system** (including the DA storage tank) during unit startup, if required.

* More information about this is provided in the last section of the module.

To prevent water hammer* when the system is being filled up, the flow should be small. Compared with the large main CEPs, the small auxiliary CEP can meet this requirement more easily. If one of the main CEPs were used, its flow rate would have to be significantly throttled, resulting in inefficient operation of the pump. Also, the recirculation line would have to open to prevent pump operational problems (such as high vibration or overheating) caused by too small a flow.

2. **To inject cool condensate to the gland seals of the BFPs.**

   This prevents egress of hot feedwater and its flashing steam from the glands of these pumps. Not only would this create a safety hazard, but the pump bearings could get overheated, and the lubricating oil contaminated.

Boiler feed pumps (BFPs)

Recall that the **main BFPs** circulate feedwater from the deaerator storage tank through the HP feedheaters and external preheaters (if any) up to the boilers. The secondary **function of these pumps** is to assist the electric heaters in the deaerator storage tank in prewarming the condensate in this tank while preparing the unit for startup. This is achieved by running one or two main BFPs in the recirculation mode such that the pump frictional heat adds to that produced by the electric heaters in the tank. As a result, the prewarming time can be significantly reduced.

⟺ Obj. 6.1 c)

However, **use of the main BFPs in the recirculation mode** for prewarming of the condensate in the DA storage tank **should be minimized**. Why? Because this mode of operation results in the following **adverse consequences and operating concerns:**

⟺ Obj. 6.1 d)

1. **A deteriorated flow pattern in the pump** (as it operates well below its design capacity) **promotes operational problems,** such as increased vibration which may reduce the pump bearing and seal life. Excessive pipeline vibration, with its attendant adverse consequences, may also occur.

2. **Severe cavitation** can occur **in the recirculation line** due to a very large pressure drop (about 6 MPa) across the control valve. The valve and piping life can be considerably reduced due to this cavitation.

You will recall that the major function of the small **auxiliary BFP*** is to supply feedwater from the DA storage tank to the boilers, following a loss of the main BFPs, and during those unit shutdowns when reactor cooling is provided via the boilers. The **secondary function of this pump** is to fill up the boiler feed system and the boilers in preparation for unit startup, if this equipment has been drained during the shutdown. Remember that the rate of filling up the system must be slow enough to avoid water hammer. The small auxiliary BFP is better suited for this job than the much larger main BFPs.

* In most units, only one auxiliary BFP is installed. Its capacity is about 3% of the full power flow. Some units have also a backup auxiliary pump of a similar capacity.

⟺ Obj. 6.1 e)

SUMMARY OF THE KEY CONCEPTS

- The secondary function of the main CEPs is to supply cool condensate required by some auxiliary systems and equipment.

- The auxiliary CEP performs two secondary functions. First, it injects cool condensate to the gland seals of the BFPs. Second, it can be used to fill up the condensate system after it has been drained for maintenance.

- The secondary function of the main BFPs is to expedite prewarming of condensate in the deaerator storage tank. To achieve this, one or two BFPs can be used in the recirculation mode. As this mode of operation reduces equipment life, its occurrence should be limited only to when it is absolutely necessary.

- The secondary function of the auxiliary BFP is to fill up the boiler feed system and the boilers (if they have been drained) in preparation for unit startup.

HOTWELL LEVEL CONTROL

In this section of the module, you will learn about the adverse consequences and possible causes of improper hotwell level, as well as the typical automatic responses to this upset. Operating concerns caused by a very low level in the condensate storage tank (sometimes also referred to as *the condensate reject tank*) are also covered.

Obj. 6.2 a) ⇔

Adverse consequences and operating concerns caused by improper hotwell level

Too low a hotwell level causes the following adverse consequences and operating concerns:

1. If the level keeps dropping, the **continuity of the long-term boiler feedwater supply – and hence, of the major reactor heat sink – is jeopardized** because the hotwell condensate inventory may soon be depleted.

   In the extreme case, it may result in a forced outage in order to secure adequate reactor fuel cooling.

2. **Cavitation of the CEPs is promoted** due to low suction head.

   Severe cavitation of the CEPs may reduce the condensate flow enough to upset DA level control. In addition, prolonged operation with a very low hotwell level may finally result in premature pump failure due to pitting and/or high vibration caused by severe cavitation.

The major **adverse consequence of too high a hotwell level** is flooding of the lowest condenser tubes. This causes reduced condenser vacuum with the adverse consequences as described in the preceding module.

Automatic responses to hotwell level

⇔ *Obj. 6.2 b)*

Typical automatic actions in response to hotwell level are depicted in Fig. 6.1, and the equipment associated with hotwell level control is shown in a pullout flowsheet (Fig. 6.10 a)) located at the module end.
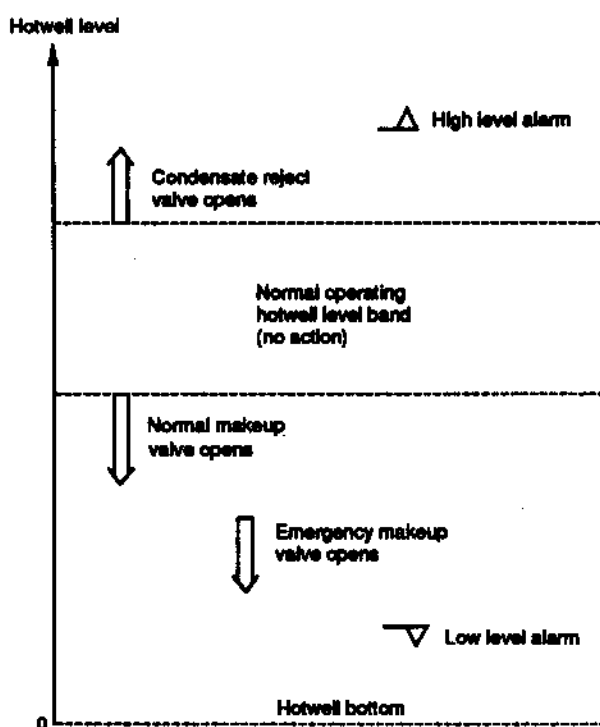

Fig. 6.1. Automatic responses to hotwell level.

As can be seen in Fig. 6.1, **no action** occurs (ie. the two makeup valves and the condensate reject valve remain closed), **as long as hotwell level is within its normal operating band**. Level excursions beyond this band are accommodated by the condensate storage tank. It acts as a surge tank: it either accepts the surplus condensate (in case of too high a hotwell level) or provides makeup water (when the level is too low). The tank is located above the condenser hotwells and operates at atmospheric pressure such that no pump is needed to transfer makeup water from this tank into the condensers – the water just cascades down. Of course, rejection of surplus condensate into the tank requires a CEP running to overcome the pressure and elevation differences.

When **hotwell level is too high**, the makeup valves should stay closed, while the following actions should occur:

1. The condensate reject valve opens with rising level to transfer the surplus condensate into the storage tank.

2. After a further level rise, a high level alarm is given to make the operator aware of this upset. In response, the operator should investigate and attempt to rectify the cause (some of them are listed later in this section).

Similarly, **when hotwell level is too low**, the condensate reject valve should stay closed, while the following actions should happen:

1. The normal makeup valve opens, and its opening increases with decreasing hotwell level.

2. If the level drops even more, the emergency makeup valve opens gradually as well. The normal makeup valve should be already fully open.

3. Finally, a low level alarm is given to alert the operator to the problem such that he/she can investigate and, hopefully, correct it.

Usually, low hotwell level occurs much more frequently than high level. This is because high hotwell level occurs only temporarily during some operating transients such as unit loading when water inside the boilers and the feedheating system undergoes a swell. On the other hand, the **demand on makeup water exists nearly all the time due to unavoidable losses of boiler water and steam**, eg. through boiler blowdown, deaerator vents and various steam and water leaks. The losses cause hotwell level to decrease gradually until makeup water is added and normal level is restored.

Causes of improper hotwell level

Normal makeup water demand and operational transients (eg. due to power manoeuvres) cause changes in hotwell level but are accommodated by the reject and normal makeup valves. However, there are a few causes of **abnormally large** hotwell level deviations; some are listed below:

1. **A very high hotwell level** can be caused by:

   a) Faulty level control which can include:

   - Malfunctioning or miscalibrated level controller;
   - A makeup valve stuck open;
   - The reject valve stuck closed.

   b) A condensate extraction pump (CEP) trip followed by failure of the standby CEP to start up.

   c) Reduced capacity of the running CEPs, eg. due to clogged strainers or air ingress through their glands.

2. A very low hotwell level can result from:

    a) Level control problems similar to the ones outlined above.

    b) A heavy demand on makeup water such that the emergency makeup valve must open to assist the normal makeup valve. This can be caused, for example, by rejection of boiler steam to atmosphere by boiler safety or steam reject valves.

    c) A large pipeline break in the condensate, boiler feed or steam system. Note that such a break would cause the condensate flow to exceed the steam flow into the condenser.

Operating concern caused by a very low level in the condensate reject (storage) tank

⇔ *Obj. 6.2 d)*

You will recall that the makeup water, that is demanded by a low hotwell level, comes from the demineralized water storage tank which is supplied from the water treatment plant. When the condensate storage (reject) tank level is high enough, some makeup water comes also from this tank, causing its level to decrease. To maintain the level, the reject tank LCV* closes and the tank refills when the condensate reject line operates on a high hotwell level.

* Fig. 6.10 a) at the module end shows the typical location of this valve. In some units, however, the location and operation of this valve are somewhat different.

Failure of this LCV to close would eventually result in emptying the condensate storage tank. This would cause **loss of condenser vacuum** due to air ingress into the condenser via the empty tank and its outlet piping. Some air would also leak through various water-sealed valves as they would lose sealing water normally supplied from the tank.

The vacuum loss would be large enough to cause a turbine trip, likely leading to a poison outage.

SUMMARY OF THE KEY CONCEPTS

*   Too low a hotwell level jeopardizes the continuity of boiler feedwater supply, particularly if the level continues to drop. In the extreme case, a forced unit outage would result to ensure adequate reactor cooling. Severe cavitation of the CEPs may also result, leading to reduced condensate flow and, if persisting long enough, pump failure.

*   Too high a hotwell level may result in flooding of the lower rows of the condenser tubes, leading to reduced condenser vacuum with its adverse consequences/operating concerns.

*   Hotwell level is maintained automatically by the condensate reject and makeup water valves. Excessive deviations of the level from its normal operating band generate the appropriate alarm.

- Possible causes of abnormally low hotwell level include controller and/ or valve problems, abnormally high demand on makeup water, or a large break in the steam and feedwater cycle.

- A very high hotwell level can be caused, for example, by faulty level control, failure of the standby CEP to start up upon a CEP trip, or reduced capacity of the running CEPs.

- A very low level in the condensate reject tank increases the risk of emptying the tank. Air ingress to the condenser via the empty tank and its outlet piping could cause a turbine trip on low condenser vacuum, leading to a likely poison outage.

Pages 53-54 ⇔

You may now work on **assignment questions 1-6**.

ASSORTED OPERATIONAL ASPECTS ASSOCIATED WITH FEEDHEATERS

The following topics are covered in this section:

- Availability of various heat sources for feedheating;
- Self-regulating feature of feedheaters;
- Abnormal feedheater drains level;
- Operation of the check valves in the extraction steam piping;
- Insufficient feedheater shell venting.

Obj. 6.3 a)-b) ⇔

HEAT SOURCES FOR FEEDHEATING

There are numerous differences between individual stations with respect to the heat sources used for feedheating. This section covers only the most typical ones.

As shown in the pullout flowsheet (Fig. 6.10) on page 69, the following heat sources are used for feedheating **in the LP feedheaters**:

1. **LP turbine extraction steam** which is the major heat input.

2. **Drains cascading from other LP feedheaters** (if any) operating at higher pressure. Compared with extraction steam, the drains contribution to feedwater heating is very small*.

* It varies from zero in No.3 heater to less than 10% in No.1 heater.

These two heat sources are **available as soon as steam is admitted to the turbine**. However, during turbine runup and at light loads, the temperature of the available extraction steam is very low*, and hence very little feedheating occurs in the LP heaters during these unit operating states.

* Recall from module 234-1 how turbine load affects the steam pressure profile in the turbine.

In the DA and storage tank, the following heat sources are used in most stations:

1. **Turbine extraction steam.**

   In most stations, extraction steam for DA heating is taken from the LP turbine, very close to its inlet. Normally, this steam is superheated. In a few CANDU units, steam for DA heating is extracted from the crossover piping between the HP and LP turbines. In this case, the steam is slightly wet.

   This major heat source is **used when turbine load is sufficiently high***. At lower loads, the extraction steam pressure – and hence, its saturation temperature – are too low to maintain the minimum required DA outlet temperature*.

   * Above 35-70% FP, in different stations.

   * About 115-130°C, depending on the station.

2. **Boiler steam** throttled by a pressure control valve.

   This heat source is **used when turbine extraction steam is unavailable and boiler steam temperature is high enough.** More information about this mode of deaerator operation is provided later in the module.

3. **HP feedheater drains.**

   Ignoring abnormal operating conditions (eg. loss of the drains pumps), HP feedheater drains are used for DA heating **at medium and high turbine loads***. At lower loads, the drains are dumped to the condenser because their pressure is too low (relative to the DA pressure) for the pumps to circulate the drains to the DA. Compared with turbine extraction steam, the drains become available at a slightly lower turbine load. However, their heat input is much smaller.

   * Above 25-50% FP, depending on the station.

4. **Electric heaters in the deaerator (DA) storage tank.**

   The heaters are less efficient than the above heat sources. This is because heat from the boilers undergoes a few energy conversions (heat → mechanical energy → electrical energy → back to heat) before it finally gets into the condensate. Therefore, though they are physically available all the time, the heaters are **used only when all the above heat sources are unavailable,** ie: during unit outage and early stages of startup. The heaters prewarm (if necessary) the condensate in the tank and maintain it at the required saturation temperature and pressure. This practice prevents introduction of cool, gas-laden feedwater to the boilers, thereby minimizing thermal stresses and corrosion.

5. **BFPs in the recirculation mode.**

   The electric heaters can be assisted by one or two BFPs operating in the recirculation mode during which large amounts of frictional heat are produced. This extra heat input significantly reduces the long time* that the heaters alone would need to prewarm the condensate in the DA storage tank from a cold shutdown condition.

   * About 1.5-2 days.

This heat source **can be used during the same unit operating conditions when the electric heaters operate.** You will recall that such operation of the BFPs is not recommended because of the adverse consequences described earlier in this module.

Among these five heat sources, turbine extraction steam and HP feedheater drains are the only ones whose use for feedheating improves the overall thermal efficiency of the unit. Therefore, they are the most preferred heat sources in the deaerator.

The typical heat sources that are used **in the HP feedheaters** in most stations are:

1. **HP turbine extraction and/or exhaust steam.**

   The latter is taken either from the crossover piping or the main moisture separators, depending on the station.

2. **Moisture separator drains.**

   Compared with the steam, moisture separator drains contribute only a few percent of the heat supplied to the HP feedheaters.

* Above 25-50% FP, depending on the station.

Other heat sources such as reheater first stage drains do not provide much heat and are used only in a few units. Therefore, they are ignored in this section. The above heat sources are **available at medium and high turbine loads***. At lower loads, these heat sources are cooler than the incoming feedwater, and therefore unavailable for feedheating. Again, this results from a low turbine steam pressure and temperature profile at light loads.

SUMMARY OF THE KEY CONCEPTS

- The major heat source in the LP feedheaters is LP turbine extraction steam. Drains cascading from other LP feedheaters contribute only a few percent to feedwater heating. Both heat sources are available as soon as steam is admitted to the turbine, although at light turbine loads, they are too cool to provide significant feedheating.

- The major heat source in the DA is turbine extraction steam. It is used when turbine load is sufficiently high.

- Below this load, the main heat input to the DA is boiler steam throttled by a pressure control valve. This heat source is available when boiler pressure is high enough.

- At high and medium turbine loads, HP feedheater drains are pumped into the DA where they contribute a few percent to feedwater heating. At lower loads, the drains are dumped to the condenser. The range of turbine load over which the drains are used for DA heating is slightly wider than that of turbine extraction steam.

- Electric heaters in the DA storage tank and recirculation from the BFPs are used during unit shutdown and early stages of startup when other heat sources are not available.

- The major heat input to the HP feedheaters is HP turbine exhaust and/or extraction steam. Moisture separator drains contribute a few percent to feedheating. In some stations, other heat sources of secondary importance are also used. All these heat sources are used for feedheating at medium and high turbine loads.

SELF-REGULATING FEATURE OF FEEDHEATERS

$\Leftrightarrow$ *Obj. 6.4*

Feedheaters are said to be self-regulating as there are **no control valves in the extraction steam piping and yet the steam flow adjusts itself in response to varying operating conditions.** Here is how it happens.

At any thermal equilibrium, the steam flow rate equals the rate at which the steam condenses in the feedheater. Steam leaks (eg. through the feedheater vents, extraction steam piping drainage equipment, etc.) and condensation in the piping are ignored here because they are usually very small in comparison with the rate at which the steam condenses in the feedheater. If we neglect the heat losses through the feedheater shell, **the rate of steam condensation depends on the rate at which heat $(\dot{Q})$ is transferred from the steam**, as expressed by the familiar equation:

$$\dot{Q} = U \, A \, \Delta T_m$$

Various operating conditions affect factors of this equation. For example:

- The overall heat transfer coefficient (U) depends on the tube cleanliness, concentration of gases in the feedheater shell, and feedwater and steam velocities;

- The tube surface area available to heating steam (A) depends on the drains level and the number of tubes plugged;

- The mean temperature difference across the feedheater tubes (ΔT_m) depends on many operating parameters as follows:

  - The feedwater flow rate and inlet temperature because they affect the average feedwater temperature inside the feedheater tubes;

  - The temperature and pressure of the extraction steam at the feedheater inlet, and the temperature and flow rate of cascading drains (if any) because they affect the average temperature of steam and drains outside the tubes.

If any one of these parameters changes, the rate of heat transfer from the steam changes accordingly. Consequently, the rate of steam condensation in the feedheater changes. Temporarily, ie. before a new thermal equilibri-

um is established, this rate differs from the extraction steam flow rate in the extraction steam piping. As a result, shell pressure changes as well. This, combined with a possible change in the extraction steam pressure at the turbine end of the extraction steam piping (eg. due to turbine loading), affects the pressure drop across this piping, and causes a corresponding change in the steam flow rate. These processes continue until a new thermal equilibrium is reached when the extraction steam flow rate balances the rate of steam condensation.

The self-regulation is facilitated by small friction losses in the extraction steam piping whose diameter is large enough to keep the steam velocity relatively low*. Thus, it takes a small change in the pressure drop in the piping to effect a large change in the steam flow.

* Recall that friction losses decrease rapidly with dropping velocity of the fluid.

From the above description, you can see how and why various operating conditions affect heat transfer through feedheater tubes, and consequently, the extraction steam flow. For example, increased feedwater flow and/or lowered inlet temperature enhance the heat transfer (by increasing ΔT_m), thereby resulting in increased extraction steam flow. A similar effect is caused by loss of the cascading drains or increased extraction steam temperature. On the contrary, tube flooding or fouling, or poor venting of the feedheater shell impairs heat transfer, thereby reducing the extraction steam flow.

SUMMARY OF THE KEY CONCEPTS

- The extraction steam flow to a feedheater adjusts itself such that it attempts to match the rate at which steam condenses in the feedheater.

- The rate of steam condensation depends on the rate of heat transfer through the feedheater tubes.

- Increased feedwater flow, lowered feedwater inlet temperature, increased extraction steam temperature and/or pressure, all enhance the heat transfer, causing more steam to flow to the feedheater.

- Tube flooding or fouling, or poor feedheater venting reduce the heat transfer and, consequently, the extraction steam flow.

You may now do **assignment questions 7-8.**

ABNORMAL FEEDHEATER DRAINS LEVEL

In the previous turbine courses, you learned how feedheater drains level is controlled during normal operation. In this section, the following aspects of abnormal feedheater drains level are discussed:

- Adverse consequences/operating concerns;
- Mitigating actions;
- Causes.

Adverse consequences and operating concerns

The normal feedheater drains level is maintained below the lowest tubes and above the inlet to the drains subcooling section*. On one hand, this prevents steam ingress to the drains subcooling section, on the other hand – flooding of the feedheater tubes. Excessive level deviations from this normal position cause serious adverse consequences/operating concerns, particularly if the abnormal level is not quickly corrected.

More specifically, **too high a feedheater drains level**:

1. **May result in water induction** to the turbine via the extraction steam piping. This may severely damage the machine.

2. **Reduces the overall thermal efficiency** due to:

   – Lowered feedwater outlet temperature as less heat is transferred to the feedwater due to tube flooding.

   – Decreased turbine efficiency due to:

      – A deviation from the design distribution of the extraction steam flows to individual feedheaters. This changes the steam pressure profile along the turbine and thus, the pressure ratio in groups of turbine stages between individual extraction steam points.

      – Impaired moisture removal from the turbine as the extraction steam flow is decreased.

   – Dumping of hot drains to the condenser (this is one of the automatic actions taken in response to a high drains level). Not only does it cause a loss of drains heat from the cycle, but it can also increase condenser pressure slightly.

   – Possible need to valve out the whole bank of feedheaters to prevent water induction to the turbine.

Too low a feedheater drains level causes the following adverse consequences/operating concerns:

1. **Equipment damage may occur** due to the following:

   – Some steam may leak into the drains subcooling section. When pockets of this steam condense in the drains subcooling section, water columns collide, producing violent **steam hammer**. The drains subcooling section may suffer severe damage.

   – If the level drops so much that steam can blow through the drains subcooling section and the drains piping, the slugs of water carried by the blowing steam can damage this equipment through **water hammer**.

- The feedheater internals (tubes, baffles, impingement plates) can get damaged due to **impingement and high flow-induced vibration** if steam flows through the feedheater too fast. This can happen (particularly in the HP feedheaters) if the drains dump valve failed in the open position, creating a large pressure difference between the feedheater shell and the condenser.

- When the feedheater drains are circulated by a **pump**, its failure to trip on the low level may lead to damage due to severe **cavitation or vapourlocking**.

2. **The overall thermal efficiency is decreased if:**

- The low level is caused by the drains dump valve failed open such that some of the feedheater drains flow directly to the condenser;

- The design distribution of the extraction steam flows to individual feedheaters is upset. This happens when the drains level is so low that some steam blows through the drains piping to the adjacent feedheater operating at a lower pressure.

Obj. 6.5 b) ⟺

Actions in response to feedheater drains level upsets

To avoid the above consequences, feedheater drains level is controlled automatically, and certain additional actions are carried out when the level gets too high or too low. Fig. 6.2 shows the valves involved in the control and protective actions, whereas the most typical of these actions are depicted in Fig. 6.3. Both diagrams are considerably simplified as there are many differences between stations:
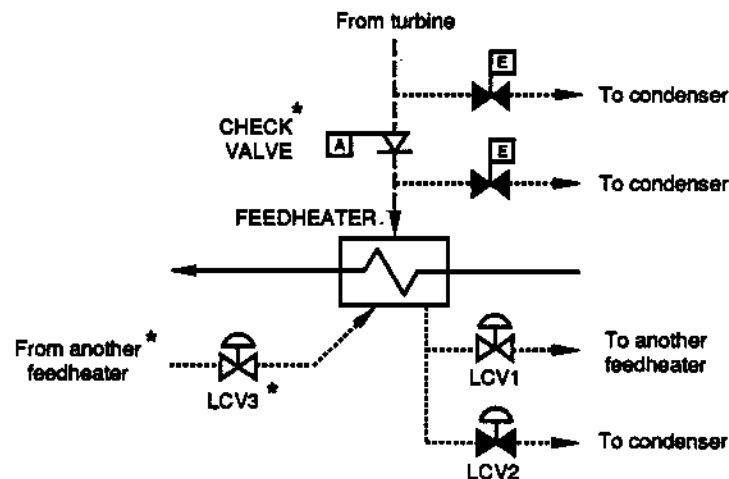
* Some feedheaters do not have it.

Fig. 6.2. Typical arrangement of the valves used for feedheater drains level control and protection:

──────── Feedwater   — —— —— —— Extraction steam
·············· Drains

LCV1 = Normal control valve; LCV2 = Drains dump valve;
LCV3 = Cascading drains valve.

Drains level

Very high level alarm
LCV3 (if any) closes
Drain valves on the extraction steam piping open
Feedheater bank isolated

LCV2 opens

High level alarm
Extraction steam check valve (if any) partially closes
Standby drains pump (if any) starts up

Normal control -
LCV1 opens

Normal water level

Normal control -
LCV1 closes

Low level alarm
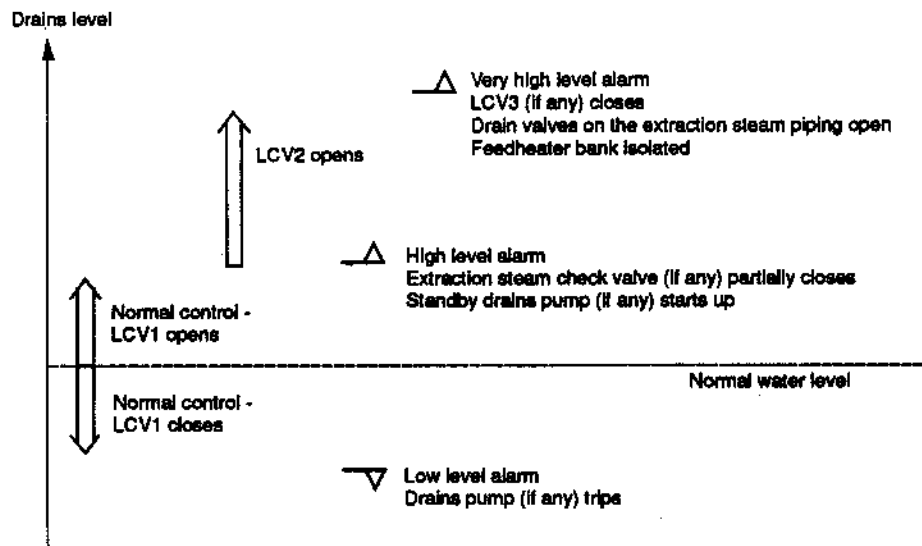Drains pump (if any) trips

Fig. 6.3. Major responses to feedheater drains level.

Some of the actions shown in Fig. 6.3 require additional comments:

1. When an alarm is received, the operator should check that the required automatic actions have occurred, and perform them manually if they have not. The normal level should be restored as quickly as possible.

2. **The drains valve (LCV2)** helps the normal control valve (LCV1) evacuate drains from the feedheater when the level is too high. **LCV2 gives the drains an additional, low resistance flow path directly to the condenser.** Thus, LCV2 can compensate for failure of LCV1 to maintain normal level.

3. Regarding **the check valve(s) in the extraction steam piping,** the valve actuator spring is usually too weak to close the valve completely against the full flow of extraction steam. Nonetheless, by closing partially, the valve **restricts the steam flow, which may be sufficient to restore the normal level.** Only when a great many tubes in the feedheater are flooded, does the extraction steam flow decrease (recall the self-regulating feature) enough for the actuator spring to close the valve completely.

    Most feedheaters have at least one check valve in their extraction steam piping. However, the No.1 and, in some stations, No.2 feedheaters have no such valves – the reason for this is explained in the next section of the module.

4. **Opening of the drain valves** in the extraction steam piping provides **an extra protection against water induction** to the turbine and prevents **water hammer.** The latter could happen upon restoration of extraction steam flow if some water were left in the piping. Though Fig. 6.2 shows only two drain valves, their actual number can be larger.

5. A very high drains level indicates a possibility of a feedheater tube rupture which would cause high pressure feedwater to enter the shell side of the feedheater. **To prevent water induction** to the turbine via the extraction steam piping, **the malfunctioning feedheater bank must be isolated.** This drastic action is necessary because **check valves cannot be relied upon to provide adequate isolation**, and some feedheaters have no check valves at all.

    To avoid unnecessary feedheater isolation in response to a level transient or due to instrumentation failure, the isolation is delayed (up to a few minutes). This limited delay does not jeopardize turbine protection against water induction because it takes a longer time for the leaking feedwater to flood the large extraction steam pipework.

    In most stations, feedheater bank isolation is done manually – automatic isolation is available only in some stations. Normally, the feedwater flow is isolated. But in some stations, the HP feedheaters are isolated on the steam side to allow for unrestricted feedwater flow to the boilers, while still protecting the turbine from water induction. And in some units, both isolation methods are combined for enhanced turbine protection against water induction.

6. Tripping the drains pump on a low drains level prevents pump damage due to severe cavitation or vapourlocking.

Obj. 6.5 c) ⇔

Causes of abnormal feedheater drains level

In the horizontal feedheaters (see Fig. 6. 11 on page 70) that are used in CANDU stations there is not much room to accommodate abnormal level: a deviation of only a few centimeters from the normal level can either uncover the inlet to the drains subcooling section or flood the lowest feedheater tubes. Therefore, feedheater level alarms occur frequently during operating transients such as power manoeuvres, turbine trips or load rejections. Causes of more serious level upsets are described below.

Abnormally high drains level can be caused by:

1. Faulty level control, eg. miscalibrated level controller or a stuck LCV;

2. Poor feedheater shell venting which can result in sufficient accumulation of gases inside the drains subcooling section to impair the syphon action;

3. Multiple tube failure, resulting in ingress of large quantities of feedwater into the feedheater shell.

Causes of **abnormally low drains level** include:

1. Faulty level control as described above;

2. Major drains leak through the feedheater shell or the drain piping.

SUMMARY OF THE KEY CONCEPTS

- Too high a feedheater drains level may result in water induction to the turbine via the extraction steam piping. The overall thermal efficiency is reduced due to impaired heat transfer in the flooded feedheater, reduced turbine efficiency, dumping of hot feedheater drains to the condenser, and possible need to isolate the faulty feedheater bank.

- Excessively low drains level may result in damage to the feedheater and/ or its drain piping, eg. due to water hammer or high flow-induced vibration. In some cases, thermal efficiency can also be reduced slightly.

- Normally, feedheater drains level is controlled by adjusting the drains outflow.

- Upon a low drains level, an alarm is given. If the drains are circulated by a pump, it should trip.

- When the drains level is too high, an alarm is given, the extraction steam check valve (if any) is assisted to close, and the drains dump valve starts to open. If the drains are circulated by a pump, the standby pump (if any) should start up.

- Upon a very high drains level, another alarm is given, and the drain valves in the extraction steam piping to this feedheater open. Drains cascading from another feedheater (if any) get routed to the condenser. If the very high level persists, the malfunctioning feedheater bank must be isolated.

- Abnormally high feedheater drains level can be caused by faulty level control, poor feedheater shell venting or multiple tube failure.

- A low feedheater drains upset can be caused by level control problems or a major leak in the drains piping or feedheater shell.

OPERATION OF THE CHECK VALVES IN THE EXTRACTION STEAM PIPING

The extraction steam piping to most feedheaters is equipped with at least one check valve. These valves are of swing type with air-to-open, spring-to-close pneumatic actuators. In each valve, the actuator and the valve disc are connected through a lost motion linkage. The linkage is arranged such that the valve disc is free to swing from the open to the closed position when the actuator is pressurized, ie. in the open position. When air is vented from the actuator, its spring attempts to close the valve. Recall that this spring is too weak to close the valve completely against full steam flow. Nonetheless, partial valve closure is effected.

Obj. 6.6 a) ⇔

The valves normally stay open, but are assisted by their actuators to close during the following operational upsets:

1. A turbine trip or load rejection.

   Recall from module 234-3 that the purpose of this action is to prevent a back flow of steam from the feedheaters to the turbine, and hence prevent excessive turbine overspeed. All the check valves should close.

2. A high drains level in a feedheater.

   The purpose of this action is explained in the preceding section. Only the valves associated with the faulty feedheater are required to close.

The extraction steam lines to No.1 (and in most stations, No.2) feedheaters have no check valves mainly because the very low pressure extraction steam in these lines cannot contribute much to turbine overspeed. Note that adequate protection against water induction to the turbine is still provided by other features such as isolation of the faulty feedheater bank.

Obj. 6.6 b) ⇔

There are two major **operational reasons why these valves**, as opposed to ordinary check valves, **are equipped with actuators**:

1. During a turbine trip or load rejection, valve closure is expedited, thereby reducing turbine generator overspeed. The actuator action also enhances feedheater drains level control by throttling extraction steam flow when the drains level is high.

* Recall from module 234-3 why these tests are important.

2. The actuators enable routine on-power tests of the valves*.

INSUFFICIENT FEEDHEATER SHELL VENTING

Recall that the HP and LP feedheater shells are vented to the condenser. In the most typical arrangement, orificed vent lines are used during normal operation. Vent bypass valves – which normally are closed – provide extra venting capacity during unit startup. This decreases the time required to remove gases (mainly air) which accumulate in feedheater shells during shutdown.

Obj. 6.7 a) ⇔

Obj. 6.7 b) ⇔

The usual **cause** of insufficient venting is plugging of vent orifices by corrosion products, salt deposits, etc. Eventually, gases accumulate in the feedheater shell to such an extent that heat transfer through the feedheater tubes is impaired due to tube blanketing. **Insufficient feedheater shell venting can be detected as follows:**

1. The feedwater outlet temperature is abnormally low for a given unit load.

2. Other potential causes of the poor feedheater performance are absent, ie.:

   – Drains level is normal;
   – Feedwater inlet temperature and flow are normal;
   – Check valves (if any) in the extraction steam piping are fully open.

To restore proper feedheater venting, **the operator should open the vent bypass valves.** Of course, the plugged orifices should be cleaned at the first opportunity.

⟺ *Obj. 6.7 c)*

SUMMARY OF THE KEY CONCEPTS

- All check valves in the extraction steam piping are assisted to close upon turbine trip and load rejection in order to minimize turbine overspeed.

- Upon a high drains level in a feedheater, the check valve(s) at the steam inlet to this feedheater is (are) actuated to close. This action helps restore the normal level, and contributes to turbine protection against water induction.

- Extraction steam check valves have actuators to enable their on-power tests and to expedite their closure during the aforementioned operational upsets.

- Improper feedheater shell venting can be caused by a plugged vent orifice.

- Two indications of this upset are abnormally low feedwater outlet temperature and absence of other possible causes of the poor feedheater performance.

- Proper feedheater venting can be restored by opening the normally closed vent bypass valves on the faulty feedheater.

You may now work on **assignment questions 9-14.**

⟺ *Pages 56-58*

DA PRESSURE AND LEVEL CONTROL

In this section, you will learn:

- How the heating steam flow to the DA is controlled;
- How DA pressure control can be lost and how it can result in damage;
- How and for what reasons the DA storage tank level is controlled;
- What can cause level upsets in this tank.

For your convenience, a pullout diagram of the DA and its storage tank is placed at the module end.

Obj. 6.8 ⇔

HEATING STEAM FLOW CONTROL

Recall that two major heat sources are used in the DA, depending on turbine load:

1. Turbine extraction steam – used when turbine load is high enough.

2. Boiler steam – used when the turbine extraction steam is unavailable, provided that boiler steam is hot enough for adequate feedheating.

These two heat sources differ also with respect to flow regulation. As for **the extraction steam, its flow to the DA is self-regulating**, similar to what happens in the other feedheaters. For example, the flow increases in response to increased feedwater flow, decreased feedwater inlet temperature, increased extraction steam pressure, or loss of the HP feedheater drains.

When **boiler steam** is used for feedheating in the DA (which happens during turbine startup and low power operation as well as during poison prevent operation), its **flow is regulated by a control valve which attempts to maintain the required DA pressure.** The valve operation is straightforward: it opens to admit more steam when DA pressure drops, and closes when the pressure rises above the setpoint.

Transfer from one heat source to the other happens automatically. For example, during turbine loading, pressure of the available extraction steam rises and eventually exceeds the DA pressure maintained by the controlled supply of boiler steam. When this happens, the check valves in the extraction steam piping open, allowing the steam to enter the DA which causes its pressure to rise. In response, the pressure control valve in the boiler steam supply line closes, reducing the flow. Eventually, the valve is fully closed. Opposite changes occur during turbine unloading, upon a turbine trip or load rejection.

Note that DA demand on boiler steam varies widely with the feedwater flow and inlet temperature. The largest demand exists during poison prevent operation, whereas a much smaller flow is required during turbine startup. For better control, two different valve sizes are used: the smaller one during turbine startup and at light loads, the larger one during poison prevent operation. Due to their duties, these valves are often referred to as *the startup valve* and *poison prevent valve*, respectively. In addition to these two valves, at least one full size standby valve is also provided to offset possible valve failure and allow for on-power valve maintenance.

SUMMARY OF THE KEY CONCEPTS.

- The turbine extraction steam flow to the DA is self-regulating.

- During startup, low power operation and poison prevent operation, boiler steam is used for feedheating in the DA. The steam flow is adjusted by a control valve which attempts to maintain the required DA pressure.

DA PRESSURE CONTROL PROBLEMS

Because the **DA operates in saturation conditions**, its pressure and temperature are correlated to each other – one cannot be changed without affecting the other. When the incoming feedwater (condensate) is heated in the DA, its final temperature determines DA pressure. How high this temperature (and hence DA pressure) can be maintained depends on a thermodynamic balance between the heat required by the incoming condensate (which depends on its flow and inlet temperature) and the heat available from the steam (which depends on its flow, pressure and temperature*). For example, when the heat required exceeds the heat available, DA pressure and temperature drop until a new balance is reached. In most cases, the self-regulating feature of extraction steam and control of the boiler steam supply are adequate to maintain proper DA pressure. Operating experience in many stations shows, however, that **some operating conditions promote DA pressure control problems which**, in the extreme case, **can produce damaging steam hammer in the feedheating system.**

The most typical scenario involves a rapid drop in DA pressure (its causes are explained later). This results in violent flashing to steam of the water in the DA storage tank and the vertical suction piping of the BFPs as shown in Fig. 6.4 a) on the next page.

⇔ *Obj. 6.9 a)*

* In most stations, the DA heating steam is superheated, and hence, its pressure and temperature are not rigidly corelated to each other.
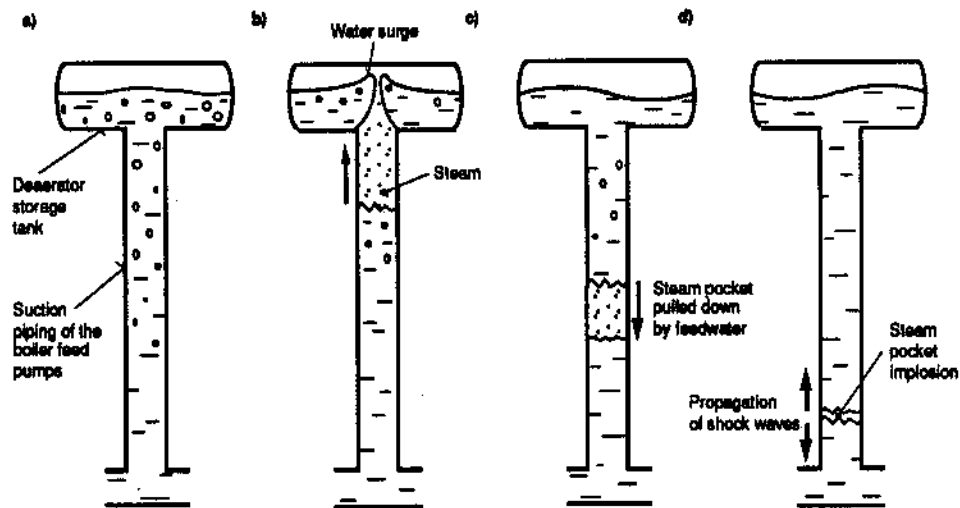
Fig. 6.4. Steam hammer due to loss of deaerator pressure.

When the steam bubbles move rapidly upward, slugs of water are driven back up into the storage tank and even the DA (Fig. 6.4 b). The **water surge** that results can damage DA internals (eg. cascade trays) and even displace the DA storage assembly as has happened in a few CANDU stations. In some cases, steam bubbles in the vertical piping from the DA to the BFPs can combine into a pocket large enough to separate water columns in the piping (Fig. 6.4 c). The pocket trapped between the water columns descends with them towards the suction of the BFPs. As the hydrostatic pressure builds up, the pocket collapses. The water columns rejoin violently, producing **high pressure shock waves** that can damage the DA storage tank, BFPs, their suction piping, valves, etc.

Operating experience shows that a rapid drop in DA pressure, possibly leading to steam hammer, **can occur due to failure of prompt supply of boiler steam to the DA** following a rapid loss of its normal heating by turbine extraction steam, while condensate continues flowing into the DA. This can happen during the following operating upsets:

- Turbine trip;

- Load rejection;

- Very high DA storage tank level caused by a DA LCV failed open.

Note that the first two of these upsets lead to the poison prevent mode of unit operation during which the LP feedheaters are inoperative, and a large feedwater flow (about 60-70% FP) is maintained. And when large quantities of relatively cool condensate are sprayed into the DA deprived of heating steam, DA pressure drops quickly.

The last of these upsets, ie. a very high DA storage tank level also results in loss of turbine extraction steam to the DA because the extraction steam check valves close to prevent water induction to the turbine. Normally, such a level upset results in stopping the condensate flow. With no condensate sprays in the DA, its pressure stays nearly constant. But if the level control is malfunctioning (ie. the DA LCV remains open), large quantities of condensate keep entering the DA, causing its pressure to drop quickly.

In all the above upsets, steam hammer is avoided if boiler steam is promptly valved in. But some operating problems (eg. too low a setpoint to the DA pressure controller or a faulty valve in the boiler steam piping to the DA) can delay this action or make it fail to happen. An excessive drop in DA pressure and steam hammer can then result as described above.

Excessively high DA pressure can also cause steam hammer, this time in the condensate system. Here is how it can happen. Under some operating circumstances, **condensate flow to the DA ceases**. This occurs, for example, when all the main and auxiliary CEPs are unavailable or when the DA level control valves close upon a high DA storage tank level. Since the condensate sprays in the DA are lost, any **boiler steam leaking** via a passing startup or poison prevent valve can raise DA pressure fairly easily.

⇔ *Obj. 6.9 b)*

Since the DA spray valves (nozzles) are never leakproof, **some steam can enter the water box**. From the water box, this steam can easily migrate into the condensate piping.

If this situation persists for several minutes, **large steam pockets** can be formed in the piping. When eventually the condensate begins to flow (eg. due to reopening of the DA level control valve), the condensate pressure increases rapidly, causing the steam pockets to implode. The resultant **collision of water columns** can inflict severe damage to the condensate system.

Though excessively high DA pressure promotes formation of steam pockets in the condensate system, it is not an absolute condition for steam hammer to occur there. Other scenarios which do not involve DA pressure control problems are described in the last section of this module.

SUMMARY OF THE KEY CONCEPTS

- A large rapid drop in DA pressure can result in steam hammer in the feedheating system. Violent flashing of water to steam in the DA storage tank and BFP suction piping can create a water surge which can damage the DA storage tank assembly. In addition, a large steam pocket can separate the water column in the BFP suction piping. When the pocket implodes on rising pressure, the water columns collide, producing high pressure shock waves which can damage the feedheating system.

- A large and rapid drop in DA pressure can occur when boiler steam is not valved in fast enough following loss of normal DA heating, and while condensate continues flowing into the DA. This can happen due to a turbine trip, load rejection or very high DA storage tank level (if the latter is caused by the DA LCV failed open) if control/mechanical problems with boiler steam supply to the DA are experienced.

- Abnormally high DA pressure can occur due to boiler steam leaks into the DA with no condensate supply.

- When excessively high DA pressure combined with loss of condensate supply to the DA persists for more than a few minutes, steam pockets can be formed in the highest point of the condensate system. Restoration of the condensate flow causes the pockets to implode. The resultant collision of water columns can produce damaging shock waves in the condensate system.

* For simplicity, it is often called short *deaerator level.*

DA STORAGE TANK LEVEL* CONTROL

In this section, you will learn about the adverse consequences and possible causes of improper DA level. Normal level control and protective actions in the event of level upsets are also described.

* The number is quoted for your orientation; you do not have to memorize it.

The normal DA level is at about 75% * of the storage tank height. At this level, the water inventory in the tank is sufficient to provide boiler feedwater for about 5 minutes at full power, and correspondingly longer at lower loads.

Obj. 6.10 a) ⟺

Adverse consequences and operating concerns caused by improper DA level

Too high a DA level causes the following adverse consequences/operating concerns:

1. **Risk of water induction** to the turbine via the extraction steam piping.

   Note that this risk is promoted due to the DA position high above the turbine.

2. **Risk of steam hammer** in the feedheating system due to possible DA pressure control problems as described in the preceding section.

3. The required protective actions (stopping the extraction steam and dumping the HP feedheater drains to the condenser) result in **reduced thermal efficiency.**

   This is of concern only if such operation is continued for a long period of time.

The following major adverse consequences/operating concerns are caused by **excessively low DA level**:

1. If the level keeps dropping, **the continuity** of boiler feedwater supply – and hence, **of the major reactor heat sink – is jeopardized** because the feedwater inventory in the tank may soon be depleted.

2. **Chances for cavitation** of the BFPs are **increased**, particularly during low DA pressure transients.

   You will recall that cavitation reduces pump capacity (hence, possible problems with maintaining boiler levels) and, if severe enough, may damage the BFPs, eg. due to high vibration.

3. The automatic protective action on a very low DA level (reactor setback) results in **loss of production**.

To prevent the above problems, DA level is automatically controlled. Additional actions are carried out when the control is ineffective.

Normal DA level control

⇔ *Obj. 6.10 b)*

Normally, DA level is controlled by adjusting the condensate inflow. For better flow control, in most stations, two different sizes of control valves are used in parallel: a smaller one during startup and at light loads, and a larger one at medium and high loads. At least one 100% standby valve is provided to reduce the risk of loss of flow control and allow for on-power valve maintenance. All these valves are located at the main CEP discharge, upstream or downstream of the LP feedheaters, depending on the station. In addition, a small level control valve (LCV) is installed in the separate discharge line of the auxiliary CEP.

At high and medium loads, DA level control incorporates typically three signals: the actual level, the condensate inflow, and the feedwater outflow[*]. The flow signals minimize level fluctuations as the level controller can "anticipate" the upcoming level change and respond to it in advance. At light loads and during startup, the flow signals are too small, and the control reverts to a single-element mode which uses only the level signal.
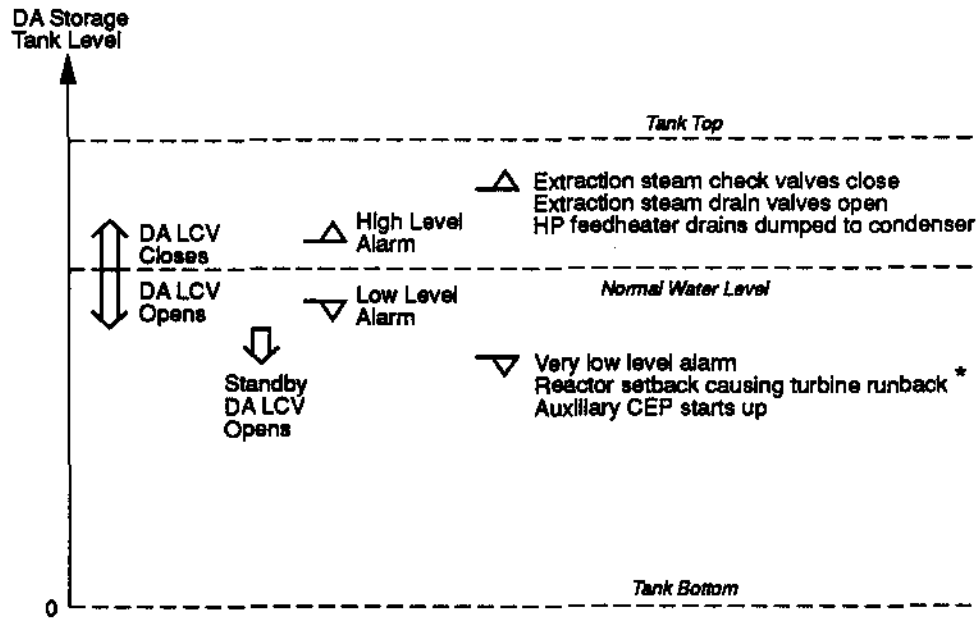
[*] In early CANDU units, a single-element control (based on the level signal) is used at all loads.

Actions in response to DA level upsets

⇔ *Obj. 6.10 c)*

Typical major automatic responses to DA level upsets are depicted in Fig. 6.5 on the next page.

NOTES & REFERENCES

* Not in all stations.

Fig. 6.5. Major automatic responses to DA level.

The general purpose of these actions is to prevent a further worsening of the level and to protect the equipment. The major concern caused by a high level is water induction to the LP turbines – note that the actions are quite similar to those carried out in response to a high feedheater drains level.

In turn, the actions performed upon a very low DA level attempt to conserve the water inventory in the DA storage tank. This is why the reactor is set back (in most stations), and the auxiliary CEP is started up. The latter action secures adequate condensate supply to maintain reactor cooling at the decay heat level via the boilers even if the main condensate flow path to the DA is unavailable.

Obj. 6.10 d) ⇔

Causes of DA level Upsets

Some of the possible causes of DA level upsets are listed below:

1. **Abnormally low DA level** can be caused by:

   a) Control/mechanical problems with the normal DA level control, eg. stuck valves, loss of instrument air, miscalibrated controller.

   b) Loss of the main condensate supply, eg. due to a CEP trip, CEP strainers clogged, valving error or major leak in the condensate system or the boiler feed system.

   c) Loss of the HP feedheater drains – note that they typically constitute about 15% of the total inflow to the DA.

2. **Excessively high DA level** can be caused by control/mechanical problems similar to those mentioned above.

Less drastic level excursions are caused by large transients in the feedwater flow which occur during unit upsets such as reactor trips, turbine trips or load rejections. Fast unit loading and unloading also produce some level transients.

SUMMARY OF THE KEY CONCEPTS

- Too high a DA level creates a hazard of water induction to the LP turbines. A rapid drop in DA pressure, possibly leading to damaging steam hammer in the feedheating system, can occur if large quantities of condensate are still supplied to the DA due to failure of its level control. Finally, the required protective actions (isolation of the turbine extraction steam and dumping of the HP feedheater drains to the condenser) reduce the unit thermal efficiency.

- Too low a DA level jeopardizes the continuity of boiler feedwater supply and hence, reactor cooling. Chances for cavitation of the BFPs are increased. Finally, the required protective actions (unit unloading, and possibly trip) result in loss of production.

- Normally, DA level is controlled by adjusting the condensate inflow to the DA. A small control valve is used during startup and at light loads, whereas a full size valve takes over the control at higher loads. Three signals – DA level, condensate inflow, and feedwater outflow – are used at medium and high loads. Only the level signal is used at lower loads.

- Excessively high DA level should result in an alarm, closure of the extraction steam check valves, opening of the extraction steam drain valves, and dumping of the HP feedheater drains to the condenser. Preventing water induction to the turbine is the major objective of these actions.

- Too low a DA level should result in a low level alarm and opening of the standby DA LCV. Upon a very low level, another alarm should be given, a reactor setback (if installed) should occur, and the auxiliary CEP should start up. The major purpose of these actions is to secure continued supplies of boiler feedwater to provide adequate reactor cooling.

- Too high a DA level can be caused by mechanical and/or control problems with the DA level control equipment. Excessively low DA level can be caused by similar control/mechanical problems, loss of main condensate supply or loss of the HP feedheater drains.

You may now work on **assignment questions 15-21**.

MAJOR CHANGES IN THE FEEDHEATING SYSTEM DURING UNIT LOADING AND UNLOADING

During unit loading or unloading, significant changes occur in the feedheating system. The boiler, DA and hotwell levels change, resulting in the appropriate action of their control valves. The number of running CEPs and BFPs may change to better match the varying feedwater flow. The extraction steam flow to individual feedheaters and their drains flows change as well. Needless to say, the feedwater temperature at the boiler preheater inlet is affected.

Obj. 6.11 a) ⇔

Let us first discuss these changes for the case of **unit loading**. Regardless of the unit mode of operation (reactor lagging or leading), loading results in increased boiler steam flow. As described in module 234-2, the **boiler level setpoint is raised**, and the actual level can either follow the setpoint closely (during slow loading) or experience a transient swell above the setpoint (during fast loading). In both cases, in the long run, boiler level control makes the **boiler level control valves (BLCVs)* open more**. This supplies additional feedwater to match the increased steam flow such that the required boiler level can be maintained. Recall from module 234-2 that in order to achieve accurate boiler level control over the whole power range, boiler feedwater flow is controlled by two different sizes of BLCVs: the small ones are used up to about 15-20% FP, at which point the large BLCVs take over. Also recall that in most CANDU stations, the boiler water inventory decreases during unit loading despite ramping up of the boiler level setpoint. Hence, during unit loading, the feedwater flow increases somewhat slower than the steam flow, particularly so when loading is fast enough to cause a transient swell in the boilers.

The increased boiler feedwater flow causes the **DA level to drop**. In response to it, the **DA LCV opens more** such that the condensate inflow can match the feedwater outflow. Again, level control is transferred from the small LCV to one of the large LCVs at about the same power level as it happens to the BLCVs.

During fast unit loading (assuming no steam discharged to atmosphere), **hotwell level actually rises** because the boiler water inventory decreases as stated above. In other words, **water that was in the boiler is now in the hotwell**. This transfer occurs as the steam inflow to the condenser exceeds the condensate outflow. If the hotwell level rises enough, the condensate reject valve opens as described on pages 9-10.

When the loading is over, hotwell level starts dropping due to numerous losses of steam and water in the whole boiler steam and water cycle. Compared with normal operation, these losses are often increased during unit startup. For example, boiler blowdown may have to be significantly increased to compensate for increased formation of crud in boiler feedwater.

This occurs mainly during unit startup due to thermal expansion of the feed-water system components, causing some deposits to flake off. Because of these losses, hotwell level decreases until the needed makeup water is added.

During slow unit loading, the accumulated effect of various steam and water losses may be predominant. As a result, **no high hotwell level is experienced**. Instead, the level cycles around the point of makeup water additions.

As the feedwater and condensate flow rates increase, so does **the number of the operating CEPs and BFPs**. Typically, loading begins with one main CEP and one main BFP running. Other pumps are started up, manually or automatically, when they are required.

Due to the self-regulating feature of feedheaters, their **extraction steam flow increases during turbine loading**. Three factors contribute to it.

First, more steam condenses when increased feedwater/condensate flow provides more cooling.

Second, turbine loading results in increased extraction steam pressure* and hence, increased saturation temperature. This increases the mean temperature difference between the steam and feedwater such that more heat is transferred resulting in increased rate of extraction steam condensation.

Third, turbine loading increases the number of feedheaters that extract steam from the turbine. Recall that while the LP feedheaters begin to operate as soon as some steam flows through the turbine, the HP feedheaters start extracting turbine steam at about 25-50% FP, and the DA at about 35-70% FP, depending on the station. At lower loads, no extraction steam flows to these heaters.

As for the **HP and LP feedheater drains**, their **flows change in unison with the extraction steam flows**.

Feedwater temperature at the boiler preheater inlet changes with turbine load as follows:

1. **At light loads, when the HP feedheaters are inoperative**, the temperature stays nearly constant. As the final stage of feedheating occurs in the DA, the final feedwater temperature is defined by the DA outlet temperature. The latter depends on DA pressure (saturation conditions, remember?) which, in turn, is maintained at a nearly constant level by the DA pressure controller admitting more and more boiler steam when unit load is being raised.

2. When unit loading is continued further, the final feedwater temperature **rises steadily** and reaches its maximum at full power. This happens because:

a) In this load range, **the HP feedheaters become operative.**

b) **The extraction steam and various drains** that are used for feed-heating **become progressively hotter** with increasing turbine load. When turbine interstage pressures rise with turbine load, the saturation temperature of the extraction steam and drains used for feedheating also increases. As a result, the outlet feedwater temperature in each feedheater increases during unit loading. This applies also to the DA, as soon as boiler steam is valved out.

Obj. 6.11 b) ⟺

To keep it short, **the major events and changes** that occur in the feedheating system **during unit unloading are opposite to what happens during loading.**

SUMMARY OF THE KEY CONCEPTS

- During unit loading, boiler level rises following the rising setpoint and, if loading is fast enough, due to transient swell of boiler water. The BLCVs open more to admit enough boiler feedwater for proper level control.

- The increased boiler feedwater flow causes the DA level to drop. In response, the DA LCV opens more.

- During fast unit loading, hotwell level increases as some water inventory is being transferred from the boilers to the hotwells. This may require condensate reject valve operation. Eventually, the level drops due to various losses of steam and feedwater. During slow loading, steam and feedwater losses are predominant, causing the hotwell level to cycle about the point at which makeup water additions occur.

- The number of operating CEPs and BFPs increases with unit load. Subsequent pumps are started up, either manually or automatically, as required.

- Extraction steam and feedheater drains flows increase during turbine loading.

- At light loads, when the HP feedheaters are inoperative, the final feedwater temperature stays approximately constant. At higher loads, the temperature rises steadily, reaching the maximum at full power.

- During unit unloading, the opposite changes occur.

You may now work on **assignment questions 22-24.**

EXCESSIVE THERMAL STRESSES AT THE BOILER PREHEATER INLET

Adverse consequences and operating concerns

When feedwater temperature at the boiler preheater inlet is too low, large thermal stresses are created in the preheater. Recall that two types of preheaters (built-in and external) are used in different CANDU stations. Naturally, their different designs affect which components experience the largest stresses when the feedwater supply is too cool. Neglecting these station specific differences, it can be stated that in the extreme case, **excessive thermal stresses may cause:**

$\Leftrightarrow$ *Obj. 6.12 a)*

1. **Preheater tube failure**, resulting in a D_2O leak with all its adverse consequences, as covered in module 234-2 where a boiler tube leak is discussed.

2. **Feedwater inlet nozzle or preheater shell failure** possibly leading to a loss of feedwater accident and hence, loss of boilers as the primary heat sink for the reactor.

To prevent these consequences, a limit is imposed in most stations on the maximum temperature difference (ΔT) between the preheater and the entering feedwater. The preheater temperature is assumed to be equal to the boiler water saturation temperature (for built-in preheaters) or the D_2O outlet temperature (for external preheaters). The imposed ΔT limit (about 130-150°C, depending on the station) is conservative enough to make the above failures very unlikely in a single event of a moderate ΔT excursion above its limit. However, a repeated violation of this limit can eventually result in fatigue failure of the stressed components.

Unit operating conditions when the ΔT limit might be exceeded

$\Leftrightarrow$ *Obj. 6.12 b)*

Note that during normal operation, preheater temperature is about 250°C, and feedwater temperature about 170°C. Thus, the preheater inlet $\Delta T = 250 - 170 = 80$°C, ie. far below its limit. However, **the ΔT limit can be approached and possibly exceeded during the following unit operating states:**

- Unit shutdown when reactor cooling is provided through the boilers operating at normal pressure;

- Unit startup and operation at light loads;

- Poison prevent operation.

Listed below are **the reasons** why these operating states promote approaching/exceeding of the ΔT limit:

1. **Feedwater temperature at the boiler preheater inlet is lowered** due to the following reasons:

   a) No feedheating occurs in the **HP feedheaters** because their heat sources are **unavailable**;

   b) **The DA cannot maintain its normal outlet temperature**, let alone compensate for the loss of the HP feedheaters. The following factors contribute to it:

   i) **The DA inlet condensate temperature is significantly reduced***, mainly because the LP feedheaters are inoperative: their heat sources are either unavailable or only slightly warmer than the condensate.

   This temperature is lowered even more when large quantities of very cool makeup water enter the condensate system. For example, this can happen during poison prevent operation in winter in the stations with no CSDVs.

   ii) **The ability of the DA to raise condensate temperature is limited.** Note that to maintain the required condensate outlet

   temperature*, the DA must supply 3-4 times as much heat to each kilogram of the condensate as during normal full power operation.

2. **In some stations which use boilers with built-in preheaters, boiler pressure is ramped up with decreasing reactor power.** Hence, during hot unit shutdown and startup, the boiler saturation temperature reaches the maximum, thereby contributing to increased ΔT at the preheater inlet.

Of course, any coincidental trouble with DA pressure control (eg. sticky valves) may further aggravate the ΔT problem.

Preventive/mitigating actions

To avoid approaching/exceeding the ΔT limit, the following **preventive actions** should be taken:

1. During unit startup from a cold shutdown state, **condensate in the DA storage tank should be sufficiently prewarmed** before admitting it to the boilers. The electric immersion heaters in the DA storage tank are the preferred heat source. Because prewarming may take up to 36-48 hours, the heaters should be switched on sufficiently early in the course of startup. If a shorter prewarming time is required, the heaters can be assisted by one or two BFPs operating in the recirculation mode (recall that this should be done only when absolutely necessary because it shortens equipment life).

2. **Boiler steam to the DA should be placed in service without any delay, and proper DA pressure should be maintained.** Any excessive drop in this pressure should be promptly rectified, eg. by raising the controller setpoint or admitting boiler steam via another PCV.

Most often, the above actions are successful so that the DA can supply boiler feedwater hot enough to satisfy the ΔT limit. However, under some operating circumstances (eg. malfunctioning DA pressure control), the DA may not be able to provide adequate feedheating because the available flow of boiler steam may be too small for the existing feedwater flow. **To return the excessive ΔT to an acceptable level,** the feedwater flow through the DA must be reduced (causing the DA outlet temperature, and hence, the preheater inlet temperature to rise) and/or the preheater temperature must be decreased. **The following actions can be taken** to achieve this:

⇔ *Obj. 6.12 d)*

1. **Reactor power reduction.**

   This action decreases heat input to the boilers, and hence their steaming rate. As the boiler feedwater demand decreases, so does the feedwater flow through the DA. The available boiler steam may then be sufficient to maintain satisfactory DA outlet temperature.

2. **Gradual reduction in boiler pressure.**

   The purpose of this action is to reduce the preheater temperature. Because boilers operate in saturation conditions, reduced boiler pressure decreases the boiler water saturation temperature. Recall that this temperature is considered as the preheater temperature in the case of built-in preheaters.

   What about external preheaters? Note that when the boiler water is cooler, so is the HT D_2O at the boiler outlet (assuming constant reactor power) such that the mean temperature difference between the two fluids is maintained. This D_2O then enters the preheater. Hence, the D_2O temperature at the preheater outlet decreases. You will recall that this temperature affects the preheater ΔT in the case of external preheaters.

   As you can see, this action is effective regardless of the preheater type.

SUMMARY OF THE KEY CONCEPTS

- Excessive temperature difference between the boiler preheater and the entering feedwater can cause preheater failure due to large thermal stresses. A D_2O leak or loss of feedwater – with their attendant adverse consequences – can result.

- Exceeding of the preheater inlet ΔT limit can occur during hot unit shutdown, unit startup and operation at light loads, or during poison prevent operation.

- During these operating states, all feedheating is performed essentially in the DA which cannot make up for the unavailability of the other feed-heaters. Because the DA outlet temperature decreases, the preheater inlet ΔT limit can be approached or even exceeded.

- The preventive actions include sufficient prewarming of the DA storage tank water inventory, and proper DA pressure control when boiler steam is used for feedheating there.

- If the ΔT limit has been exceeded, a reactor power reduction or a gradual boiler cooldown can be carried out to return the ΔT to an acceptable level.

Pages 63-64 ⇔   You may now work on **assignment questions 25-27**.

OPERATION WITH SOME FEEDHEATERS OUT OF SERVICE

Introduction

In this section, you will learn about the effects of loss of some feedheaters on the final feedwater temperature, extraction steam and drains flows in the remaining feedheaters, thermal efficiency of the unit, and the generator output. Major reasons why some unit derating may be necessary will be also explained.

First, recall the typical arrangement of feedheaters in CANDU units, as shown in Fig. 6.6. Normally, both banks (A and B) of the LP and HP feedheaters are kept in service. **When a serious operational problem arises** (eg. a feedheater tube rupture), the faulty feedheater must be valved out for equipment protection and personnel safety. However, the typical arrangement of feedwater piping and isolating valves is such that **individual feedheaters cannot be valved out**. Instead, **a whole bank of feedheaters must be removed from service**. In most stations, the isolation is performed on the feedwater side by closing the isolating valves at the inlet and
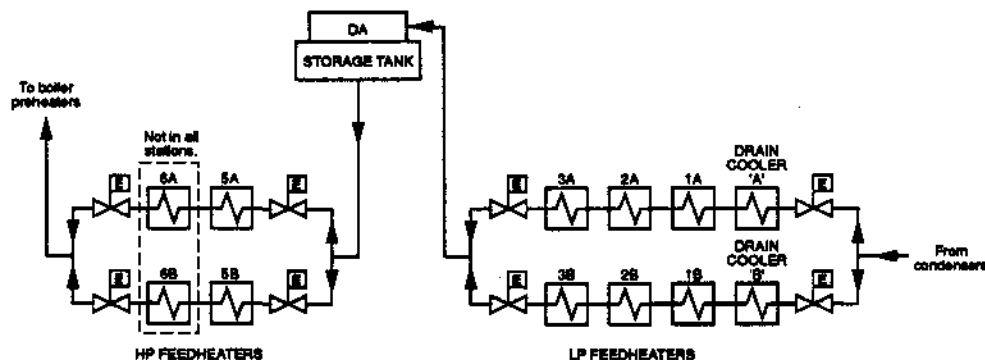

Fig. 6.6. Arrangement of feedheaters in CANDU units.

outlet of the faulty feedheater bank. You may recall that in some stations, individual HP feedheaters can be isolated on the steam side.

When either of the LP and/or HP feedheater banks is valved out, unit operation can be continued because the feedwater flow path to the boilers is still available. In the stations where the HP feedheaters can be isolated on the steam side, it is possible to keep the unit in service even with both banks of these heaters isolated. While, in principle, full unit output can be maintained in the single bank mode of feedheater operation, a significant loss of feedheating (ie. more than one bank) may force some unit derating, typically less than 10% of full power. More information about this is provided later in this section.

Unlike the LP and HP feedheaters, only one DA is installed. Therefore, its **unavailability** (although very unlikely to occur) **can force a unit shutdown** as there is no feedwater bypass around the DA. In addition, operation with a faulty DA would increase concentration of gases in feedwater and steam, causing accelerated corrosion of the boilers, feedwater system, turbine, etc. For these reasons, it is assumed in this section that the DA remains in service whereas loss of feedheating is limited only to some LP and/or HP feedheaters.

Effects of loss of some feedheaters on unit operation

We will first discuss the effect of loss of a single bank of feedheaters on the extraction steam and feedheater drains flows in the feedheaters remaining in service.

Recall that due to their self-regulating feature, feedheaters condense more extraction steam when the feedwater flow increases and/or its inlet temperature decreases. Let us first consider the **feedheaters operating in the single bank mode.** Compared with normal (double bank) operation, the **feedwater flow essentially doubles,** assuming the boiler feedwater demand stays unchanged. The drastically increased feedwater flow **enhances heat transfer** in these heaters due to the following effects:

- The mean steam-to-feedwater temperature difference across the tubes increases due to a reduction in the average feedwater temperature in the feedheater tubes. The latter occurs because a single bank of feedheaters cannot raise feedwater temperature as much as it can when the other bank is in service.

- Convection of heat from the feedheater tubes is enhanced because feedwater velocity in the tubes is twice as high as during normal operation[*].

* The overall heat transfer coefficient increases much less than the water velocity, though.

It is important to realize that **the improved heat transfer does not compensate entirely for the loss of the sister bank of feedheaters.** For this to happen, the bank remaining in service would have to transfer twice as much heat as during normal operation (because the feedwater flow

through this bank has doubled), with no change in the mean steam-to-feedwater temperature difference across the tubes (because the feedwater temperature rise is assumed unchanged). Clearly, these two requirements are mutually exclusive. In reality, the **feedwater temperature rise is reduced to about 75-85% of its normal value.** Not bad, considering that the available tube surface area is reduced to 50%.

Note that this single bank of feedheaters now consumes much more steam than its normal 50% share. For example, if the steam flow is changed from 50% to 80%, the relative increase is (80 - 50) / 50 = 0.6 = 60%. Consequently, the **feedheater drains flow also increases by 60%.** This increase is too large for the drains to be handled in the normal cascade arrangement. Therefore, when feedheaters operate in the single bank mode, their drains cascade lines are isolated, and **the drains dump valves open, discharging the drains directly to the condenser.** This changes the drains flows in the individual feedheaters in this bank. Consider, for example, the LP feedheaters shown in Fig. 6.7.

a) Normal double bank operation
Note: Steam and water flows in bank 'B' are identical.
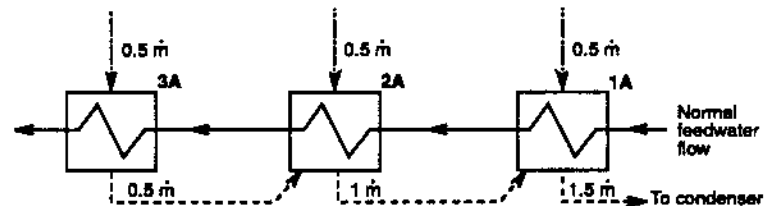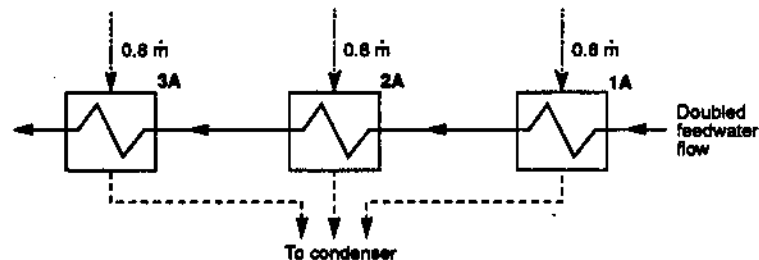
b) Single bank operation

Fig. 6.7. Approximate effect of feedheater mode of operation on extraction steam and feedheater drains flows:
———— Feedwater   —·—·— Extraction steam   - - - - - Drains

For simplification, it is assumed that during normal operation each feedheater pair (eg. 1A + 1B) shares the total extraction steam flow (ṁ) equally, and that this flow drops to 80% during single bank operation. By comparing parts a) and b) of this drawing, you can see that the 3A heater operates with increased drains flow, whereas the drain flows in the other two heaters are decreased.

How are the remaining feedheaters affected? To answer this question, let us discuss separately two major cases.

Case A: **Loss of one bank of LP feedheaters.**

As described above, the LP feedheaters remaining in service cannot make up entirely for this loss. As a result, cooler condensate enters the DA. Due to its self-regulating feature, the **DA extracts more steam** from the turbine. Assuming a constant turbine load, and ignoring small pressure losses in the DA extraction steam piping, **extraction steam pressure in the DA remains approximately constant.** Hence, the extraction steam condenses in the DA at roughly the same unchanged saturation temperature. And because the DA – where steam and condensate mix thoroughly together – operates in saturation conditions, **the outlet condensate temperature stays constant.**

Since the feedwater flow and inlet temperature in the **HP feedheaters** are not changed, their **extraction steam and drains flows remain unchanged,** too.

Case B: **Loss of one bank of HP feedheaters.**

Assuming that the feedwater flow remains constant, **operation of the LP feedheaters, and** (in most stations) **of the DA is not affected** for the following reasons:

– The LP feedheater tube surface area has not been reduced;
– The condensate inlet temperature stays the same (assuming approximately constant condenser pressure);
– The extraction steam pressure and temperature remain unchanged (assuming that the turbine steam pressure profile has not changed much);
– In most stations, supply of the HP feedheater drains to the DA is continued because the standby drains pump in the HP feedheater bank in service starts up and helps the duty pump handle the increased drains flow*.

Based on the above, let us now discuss, the effect on **the final feedwater temperature** (ie. at the boiler preheater inlet).

In case A, this temperature is not affected because the DA and the remaining bank of the LP feedheaters compensate entirely for the loss. **In case B, this temperature decreases** because there are no other feedheaters downstream. The decrease is, however, minimized by the remaining bank of the HP feedheaters where heat transfer is enhanced as described earlier.

The largest decrease in the final feedwater temperature happens when both banks of the HP heaters are isolated only on the steam side, allowing for feedwater flow to the boilers. You will recall that such operation of the HP heaters is possible only in a few units.

* In some units, no standby HP feedheater drains pumps are fitted. Because the single drains pump cannot handle the increased flow, some drains get dumped to the condenser. Since the heat of the dumped drains is lost for the DA, its extraction steam flow increases slightly due to the self-regulating feature.

⇔ *Obj. 6.13 a) ii)*

NOTES & REFERENCES

Obj. 6.13 a) iii) ⟺

The above changes in the extraction steam and feedheater drains flows, and possibly in the final feedwater temperature, decrease the thermal efficiency of the unit. Before we list the contributing factors, let us first make two observations regarding changes in extraction steam flows caused by removal of a feedheater bank from service.

First, **the total flow of extraction steam is reduced.** This is obvious in case B, where the remaining bank of the HP feedheaters extracts less heat than normally both banks do, while operation of the LP heaters and the DA is not changed. In case A, the effect is more difficult to notice because changes to the DA and LP feedheater extraction steam flows are opposite. However note that, compared with the LP heaters, the DA uses hotter steam which possesses more heat. Therefore, the DA uses less steam than the LP feedheaters to supply a given amount of heat to feedwater.

When less steam is extracted from the turbine, more steam is exhausted to the condenser, assuming that the turbine inlet pressure remains unchanged. As a result, condenser pressure increases slightly, causing each kilogram of turbine steam to do less work. In addition, moisture removal from the turbine is hindered due to reduced steam extraction.

The second observation is that **the normal distribution of extraction steam to individual feedheaters is upset**: some of them take more steam, and others less, than during normal operation. This changes the flow of turbine steam between various extraction points, and consequently, the turbine steam pressure profile. This is illustrated in Fig. 6.8, where a simplified turbine with only one extraction point is shown.
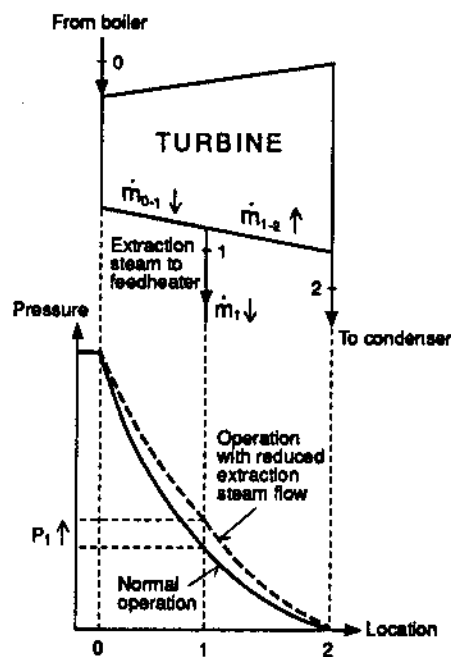
When the extraction steam flow ($\dot{m}_1$) is reduced, more steam ($\dot{m}_{1\text{-}2}$) flows through the downstream stages of the turbine. To overcome turbine resistance to the increased flow, the inlet pressure (p_1) to this group of stages must increase. Assuming that constant turbine inlet pressure (p_0) is maintained, the flow ($\dot{m}_{0\text{-}1}$) through the first group of stages decreases

Fig. 6.8. Effect of reduced extraction steam flow ($\dot{m}_1$) on the turbine steam pressure profile.
(Symbols explained in text)

due to the increased backpressure (p_1). The net result is that the turbine inlet steam flow is reduced, and the pressure ratios in both groups of stages have deviated from their normal values. Needless to say, **turbine efficiency and output are affected.**

Let us now gather the factors that contribute to reduced thermal efficiency of the unit due to removal of some feedheaters from service:

1. **More heat must be supplied** in the boiler preheaters **to each kilogram of feedwater** when its inlet temperature is reduced.

2. **Each kilogram of turbine steam performs slightly less work** due to a small increase in condenser pressure. The latter happens because the condenser thermal load is increased for two reasons:

    a) The turbine exhaust steam flow is increased as explained above.

    b) Some feedheater drains are dumped directly to the condenser.

3. **Turbine efficiency is slightly reduced** due to two effects:

    a) More moisture is left in the turbine when the total extraction steam flow is reduced.

    b) Some turbine stages operate off their optimum pressure ratio due to changes in the turbine steam pressure profile*.

Though none of the above effects is strong, together they can reduce the thermal efficiency of the unit by a few percent.

What happens to **generator output depends on the unit mode of operation.** In the reactor lagging mode, the overall unit control attempts to maintain generator output at its setpoint. To achieve it, reactor power (and hence, the turbine steam flow) must be sufficiently increased to compensate for reduced thermal efficiency. This automatic control action may or may not be successful, depending on the limits on the maximum reactor power and opening of the governor valves.

In the reactor leading mode, where reactor power is typically kept constant, the generator output decreases proportionally with the reduced thermal efficiency of the unit. A manual adjustment of the reactor power setpoint is therefore required to return to the full generator output. Success of this action would depend on the aforementioned limits regarding reactor power and the governor valves.

The above description is valid under the assumption that no unit derating is necessary. However, a significant loss of feedheaters (more than one bank) may force some unit derating (up to 10% of full power), regardless of the mode of unit operation. Why this action may be necessary is explained in the next section of the module.

⇔ *Obj. 6.13 a) iv)*

SUMMARY OF THE KEY CONCEPTS

- In the typical arrangement of feedheaters used in CANDU units, individual feedheaters cannot be isolated when a serious operational problem arises. Instead, a whole bank of heaters must be removed from service.

- In the feedheaters operating in the single bank mode, the feedwater flow doubles. The enhanced heat transfer that results, increases the extraction steam flow from the 50% of the normal total flow to about 75-85%.

- When a bank of the LP feedheaters is isolated, the DA extracts more steam from the turbine and maintains the normal condensate outlet temperature. Therefore, the extraction steam and feedheater drains flows in the HP heaters remain unchanged. So does the final feedwater temperature.

- Valving out a bank of the HP feedheaters increases the extraction steam and feedheater drains flows in the remaining bank of these heaters. In addition, the DA extraction steam flow is increased slightly. Operation of the LP feedheaters is not affected. The final feedwater temperature is decreased.

- The feedheater drains flow changes in unison with the extraction steam flow. In the heaters operating in the single bank mode, the normal drains cascade lines are isolated, and the drains are dumped to the condenser.

- When some feedheaters are valved out, the unit thermal efficiency is reduced because condenser pressure is slightly increased, turbine efficiency is reduced, and the boiler may have to supply somewhat more heat per kilogram of feedwater.

- The effect of feedheater isolation on the generator output depends on the unit operation mode. In the reactor leading mode, the output decreases proportionally with the thermal efficiency of the unit. In the reactor lagging mode, the output is maintained constant if reactor power and turbine steam flow can be increased enough to compensate for the reduced thermal efficiency. In both modes of operation, some derating may be necessary if the feedheater loss is excessive.

Obj. 6.13 b) ⇔

Unit derating due to isolation of too many feedheaters from service

In principle, the LP and HP feedheaters can operate in the single bank mode with no need to derate the generator output. However, a significant loss of feedheaters (usually more than one bank) may force some unit derating for any one of the following **reasons**:

1. **To prevent damage to some of the feedheaters remaining in service.**

As explained earlier, valving out some of the feedheaters results in increased feedwater and/or extraction steam and drains flows in some of the remaining feedheaters.

Eventually, the increased steam and feedwater flows can damage some of these heaters through **increased impingement, flow induced vibration and erosion**. In addition, feedheater tubes and baffles in the drains subcooling section can be quickly devastated by **steam hammer**. The latter is initiated by the drains flashing to steam when the pressure in the drains subcooling section decreases excessively. The cause of it is increased friction losses due to the large drains flow (recall that friction losses increase rapidly with the flow velocity).

To prevent feedheater damage, it may be necessary to limit the steam, drains, and feedwater flow rates. This is why some derating may be required.

2. **To prevent overstressing and accelerated erosion of some turbine components.**

   Since the total extraction steam flow to all the feedheaters remaining in service is reduced in comparison with normal operation, the steam flow and pressure drops in the last stages of the LP turbine are increased. This results in **increased stresses in the blades and diaphragms of the affected** stages, and **may increase the thrust bearing load**. In addition, since less steam is extracted from the turbine, more moisture is left, promoting faster erosion of turbine components.

   To prevent these adverse effects, some derating may be necessary.

3. **To prevent boiler pressure drop.**

   Recall that any feedheater isolation decreases the unit thermal efficiency so that reactor power must be increased to maintain generator output. **If a limit on the reactor power is reached** before the normal generator output is restored, a certain reduction in the latter must be accepted. Any attempt to load the generator further (assuming that the governor valves can admit more steam to the turbine), would result in a boiler pressure decrease as more heat would be removed with the steam than the reactor could supply. Recall from module 234-3 that in response to low boiler pressure, the BPC program (backed by the low boiler pressure unloader in the turbine governing system) would automatically unload the turbine generator. Hence, unit derating would automatically happen.

4. **To prevent exceeding the operating limits on the CCW temperature rise and the effluent temperature.**

   When thermal efficiency of the unit is reduced, reactor power must be increased in order to maintain generator output. This results in **more heat rejected in the condenser to CCW**. As a result, the CCW tem-

perature rise and the station effluent temperature rise. Under some operating circumstances (eg. a hot summer day), this may be enough to exceed the associated limits. A minor derating of the unit may be necessary, as outlined in the previous module.

The above list is by no means complete. Other feedheating-related problems may also require some unit derating. For example, loss of normal DA heating by turbine extraction steam would result in automatic supply of boiler steam to the DA. The DA pressure would decrease, resulting in a corresponding decrease in the final feedwater temperature. To compensate for these effects, reactor power would have to be raised. If its limit were reached, unit unloading on low boiler pressure may occur as described in point 3 above.

As for the magnitude of the required unit derating for different combinations of feedheaters valved out, it should be specified in the appropriate operating manual, based on the data provided by the turbine and feedheater manufacturers. The amount is typically in the order of 5-10% of full power. When a CCW temperature limit is exceeded, the required unit derating can be easily calculated, assuming that the CCW temperature rise is approximately proportional to the station MW_e output.

A final remark: it is enough to remember any three of the above four items to meet the corresponding training objective (#6.13 b).

SUMMARY OF THE KEY CONCEPTS

- When too many feedheaters are valved out, some unit derating may be necessary in order to prevent feedheater damage, overstressing and accelerated erosion of turbine components, or exceeding of the CCW operational limits. Boiler pressure control would also reduce generator output if reactor power could not meet the turbine steam demand.

You may now work on **assignment questions 28-32**.

ALTERNATE SOURCES OF BOILER FEEDWATER

Interunit feedwater tie (IUFWT)

In the majority of multiunit stations, the availability of an adequate supply of boiler feedwater is increased by cross-connecting the BFPs and boilers of different units via a common header, as shown in Fig. 6.9.
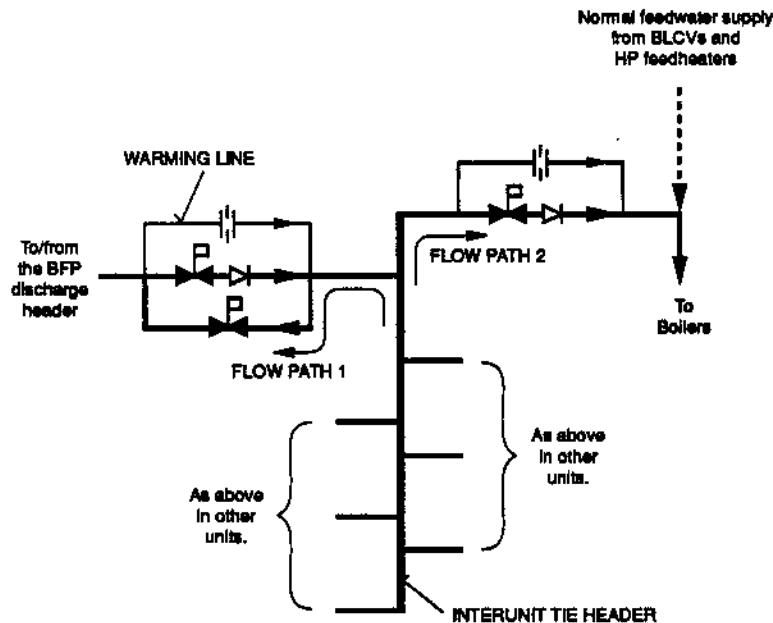
Fig. 6.9. Simplified interunit feedwater tie in a multiunit CANDU station.

The flow capacity of the IUFWT is about 3% of the full power feedwater flow of one unit. This is sufficient to provide adequate cooling of a tripped reactor, when only the decay heat and HT pump heat must be removed.

⇔ *Obj. 6.14 a)*

The IUFWT is normally kept in the poised state, with the isolating valves closed as shown above. A small flow is maintained through the warming lines to keep the system warm and to ensure that it is always filled with water. This practice prevents thermal shock and water hammer when the system starts supplying feedwater.

Upon a **total loss of feedwater** * in any unit, the proper isolating valves are automatically opened, allowing for feedwater supply from the BFPs of the operating units to the boilers of the affected unit. Note in Fig. 6.9 that two flow paths are available to supply feedwater to the incident unit:

⇔ *Obj. 6.14 b)-c)*

* Recall that this can be caused by a loss of all BFPs (mains and auxiliary), a large break in the feedwater system, or a valve failure/error isolating the normal feedwater flow path to the boilers.

Path 1: Via the BFP discharge header and then the rest of the feedwater system. This is the preferred path because the BLCVs can control boiler levels – hence, no need for manual level control. The path is available only when loss of feedwater is caused by a total loss of the BFPs, whereas the rest of the feedwater system in the affected unit is fine.

Path 2: Directly to the boilers. This path is used when the normal feedwater flow path in the affected unit is unavailable due to a large break, valve failure, etc.

SUMMARY OF THE KEY CONCEPTS

- The IUFWT is required to operate upon a total loss of feedwater in any unit.

- When this happens, the proper isolating valves in the IUFWT are automatically opened, allowing for feedwater supply to the boilers of the incident unit from the BFPs of the operating units.

- The flow capacity of the IUFWT is about 3% of the full power feedwater flow of one unit. This allows for adequate cooling of the tripped reactor.

Combined unavailability of the auxiliary BFP and the IUFWT

Obj. 6.15 b) ⟺

* Note that proper operation of this pump requires that the DA level control, the auxiliary CEP and the makeup water system be available. When any one of them is not, the auxiliary BFP is considered unavailable, too.

When the auxiliary BFP* and the IUFWT are both unavailable (due to maintenance work or equipment failures), the unit is deprived of the major backup feedwater supply. This backup supply is very important because it can maintain adequate reactor cooling via the boilers in the event of loss of normal feedwater supply by the main BFPs. Though the combined unavailability of the auxiliary BFP and the IUFWT creates no immediate hazard to the unit (after all, feedwater is still being supplied by the main BFPs), **prolonged operation in this condition increases chances for a coincidental loss of normal feedwater supply**, eg. due to a loss of class IV power.

* This is explained in the next section of the module.

If this happened, the unit would experience a **total loss of boiler feedwater** which **would jeopardize the major reactor heat sink**. Also, the **boilers may be subjected to unfavourable operating conditions** due to uncovering boiler tubes and, possibly, the use of the emergency boiler cooling system and/or the emergency water system (depending on the station)*. The tube uncovering would happen during a HT system cooldown performed in order to place an alternate reactor heat sink (the shutdown or maintenance cooling system, depending on the station) in service in an orderly manner. Alternatively, the shutdown cooling system would have to be valved in at elevated temperature, reducing the system's life expectancy due to large thermal stresses.

Obj. 6.15 a) ⟺

To enhance reactor safety, and to minimize chances for the aforementioned adverse operating conditions, a time limit (usually about 8-24 hours) is imposed on the sustained combined unavailability of the auxiliary BFP and the IUFWT. When neither one can be returned to service within the time limit, the operator must **shut down and cool down the reactor** in a controlled manner. This action, performed when normal feedwater supply is still available, allows the operator to prewarm and place an alternate heat sink in service without compromising reactor safety. Also, this does not subject the boilers to the unfavourable operating conditions mentioned above.

SUMMARY OF THE KEY CONCEPTS

- · The reactor must be shut down and cooled down in an orderly manner, before the limit on the sustained unavailability of the auxiliary BFP and the IUFWT is exceeded.

- This action, performed when the normal feedwater supply is still available, allows the operator to place an alternate heat sink for the reactor in service in an orderly manner. As a result, reactor safety is not compromised and potential adverse operating conditions in the boilers are avoided.

Other sources of boiler cooling water

Though very unlikely, a **total loss of feedwater** can happen. This would require both the normal (via main BFPs) and the auxiliary (via auxiliary BFP or IUFWT) supplies of feedwater to be unavailable at the same time. When neither one can be quickly restored, either one or both of the following systems (depending on the station) can be used to supply cooling water to the boilers:

⇔ *Obj. 6.16 a)*

1. **Emergency boiler cooling system (EBCS)** also known as the boiler emergency cooling system (BECS).

    This system is installed in some CANDU stations, and supplies cooling water to the boilers only.

2. **Emergency water system (EWS)** also known as the emergency service water system (ESWS).

    The system is installed in newer CANDU stations. It supplies cooling water not only to the boilers, but also to other critical loads such as the reactor vault coolers, HT pump gland cooler, etc.

Since these systems differ significantly, their detailed description is left to station specific training. Nevertheless, they have the following features in common:

* In most stations, demineralized water (stored in a special tank) is used for the first 30 min. When its inventory is gone, and the boilers are still needed as a heat sink, raw water is pumped into the boilers.

- Raw, **chemically untreated water** is used for long-term* heat removal;

- **The cooling water** supplied to the boilers is at ambient temperature, ie. **not preheated;**

⇔ *Obj. 6.16 b)*

- **Boiler pressure must be drastically reduced** before cooling water can be fed into the boilers.

Of course, the use of raw cooling water would result in **contamination of the boilers**. Hence, a thorough cleanup would be required to avoid premature failure due to corrosion. In addition, the boilers would be subjected to **thermal shock** due to the low temperature of the cooling water. For these reasons, the EBCS/EWS are the least preferable emergency heat sink for the reactor. They are used only when other methods of heat removal from the HT system have failed.

SUMMARY OF THE KEY CONCEPTS

- In the event of a total loss of all other sources of boiler feedwater, the EBCS (or EWS, depending on the station) can provide cooling water to the boilers.

- Boiler pressure must be drastically reduced before either system can supply water to the boilers.

- In most stations, both systems are the least preferable emergency heat sink for the reactor because they result in thermal shock to the boilers as well as their contamination (if raw water is used).

Pages 66-67 ⇔

You may now work on **assignment questions 33-35**.

CAUSES OF STEAM OR WATER HAMMER IN THE FEEDHEATING SYSTEM

Obj. 6.17 ⇔

Operational experience in many power stations in the world shows that in the feedheating system, damaging steam or water hammer can be caused by several improper operating practices and/or some equipment failures. One of these causes, namely DA pressure control problems, has been described earlier in this module. Described below are other **causes**:

1. **Improper pump startup techniques**:

    a) Pump started with its discharge valve fully open.

    b) Pump started with voided discharge lines (if the pump capacity is large enough to result in priming of these lines too quickly).

    In both cases, the water flow increases rapidly, and impinges abruptly on the pump discharge lines, particularly in the places where the direction of flow is forced to change (elbows, tees, valves, heat exchangers, etc.). Large pressure surges and impact forces result, with possible equipment damage.

    Regarding system priming, the right technique is to use a small pump (eg. the auxiliary – rather than a main – CEP)*, and to throttle the flow.

2. **Failure to drain** the extraction **steam** and/or the boiler steam to the DA **lines** (eg. due to malfunction of a drain valve or steam trap).

    This can result in slugs of water driven by high velocity steam. Their impact on pipe elbows, headers, valves, etc. may result in failure.

3. **A very low feedheater drains level** can result in steam and water hammer*.

* In some stations, the system layout is such that the auxiliary CEP cannot be used to prime the condensate system. In this case, one of the main CEPs must be used for this purpose.

* See pages 17-18 for details.

4. **Loss of condensate flow through the gland steam condenser and air ejector condenser*** without isolating their steam loads.

This can be caused by improper shutdown practices (eg. shutting down the condensate system prior to the gland steam sealing system), loss of all CEPs, or failure of the CEP recirculation line to maintain the required minimum flow of condensate. In any case, given enough time, loss of cooling to these condensers will eventually result in **formation of steam pockets** in the condensate. When the condensate flow is restored, the pockets condense (due to increased pressure), resulting in violent water hammer due to **collision of water columns** previously separated by the steam voids.

5. **Sustained loss of condensate or feedwater flow combined with excessive water leakage out of the system.**

This is a bit similar to the scenario described in point 4 because it also involves formation of steam pockets. In order to understand why this can happen, one must realize that in reality no fluid system is perfectly leakproof. Even when the pumps are stopped, water can leak through various valves, pipe flanges, etc. **When the leakage out of the system exceeds the leakage in, system pressure decreases and can eventually reach the saturation pressure.** If the pressure tends to drop further, **vapour pockets are formed** in the highest points of the system where the local hydrostatic pressure is relatively low (of course, any heat input to the water, whose example is given in point 4, promotes this process).

Consider, for example, the condensate system shown in a pullout diagram (Fig. 6.10 a) on page 69. When the condensate flow to the DA is stopped due to the closure of the DA LCV on high DA level, the water trapped in the long vertical pipe run to the DA can gradually leak out. Some of the possible leakage paths include DA spray valves, pipeline drain and vent valves, or the DA LCV stem gland. When the leakage past the closed DA LCV cannot compensate for the total out-leakage, the condensate pressure starts decreasing. Given enough time, the pressure may drop enough for vapour pockets to start forming in the highest point, ie. in the horizontal pipe at the DA inlet. Note that for this to happen, steam leakage from the DA into the condensate piping is not a necessary condition – it merely promotes the steam pocket formation.

A potentially worse situation occurs when all the CEPs are tripped for a prolonged period of time (say, 20-30 minutes) because this opens more out-leakage paths. For example, leakage can occur through the CEP recirculation line control valve passing, or the condensate reject valve passing or held open by the hotwell level controller.

In a similar way, steam/water hammer can occur in the boiler feed system, where out-leakage is promoted by high system pressure, whereas boiling by high temperature.

Note that **a short-lasting interruption in the condensate/feedwater flow** (up to several minutes) **is usually of no concern.** There is just not enough time for large vapour pockets to form in the piping. However, if the flow interruption lasts longer than that, precautions must be taken to avoid damaging water hammer while reestablishing the flow. Detailed practices to achieve this are left to station specific training.

SUMMARY OF THE KEY CONCEPTS

- Typical causes of steam or water hammer in the feedheating system include improper pump startup techniques, inadequate draining of the heating steam pipelines, very low feedheater drains level, and formation of steam pockets in the condensate/feedwater system.

- Improper pump startup techniques can result in water hammer due to the flow increasing rapidly and impinging abruptly on the pump discharge lines.

- Inadequate drainage of the heating steam lines to feedheaters can cause water hammer due to slugs of water driven by high velocity steam.

- Steam/water hammer occurs when water columns, previously separated by steam pockets, collide. Such steam pockets can be produced due to loss of the condensate flow through the gland steam condenser and air ejector condenser. Steam pockets can also be formed in the highest points of the condensate or boiler feed system. This can be caused by a sustained loss of condensate or feedwater flow combined with excessive water leakage out of the system. DA pressure control problems can also lead to formation of large steam pockets in the system.

You can now work on **assignment questions 36-38.**

ASSIGNMENT

1.　a)　The secondary function of the main CEPs is _____

_____

_____

_____

　　b)　Two secondary functions of the auxiliary CEP are:

　　　　i)　_____

_____

　　　　ii)　_____

_____

2.　a)　The secondary function of the main BFPs is _____

_____

_____

　　b)　The reasons why use of the main BFPs for prewarming condensate in the deaerator storage tank should be minimized are:

　　　　i)　_____

_____

_____

　　　　ii)　_____

_____

_____

　　c)　The secondary function of the auxiliary BFPs is _____

_____

_____

3.　a)　The adverse consequences/operating concerns caused by too low a hotwell level are:

　　　　i)　_____

_____

　　　　ii)　_____

_____

b)   A very low hotwell level creates an immediate, ie. within several seconds, risk of overheating the reactor fuel. (False / true)

c)   A low hotwell level transient, eg. due to a power manoeuver, (is / is not) likely to cause cavitation damage to the CEPs.

d)   The major adverse consequence of a very high hotwell level is

_____

_____

4.   a)   The following automatic actions (listed in the order of decreasing level) should occur when hotwell level is too low:

    i)   _____

    ii)   _____

    iii)   _____

b)   Too high a hotwell level should cause the following automatic actions (listed in the order of increasing level):

    i)   _____

    ii)   _____

c)   No control valve action occurs when hotwell level is within its normal operating band. (False / true)

5.   a)   Abnormally high hotwell level can be caused by:

    i)   _____

    ii)   _____

    iii)   _____

b)   Abnormally low hotwell level can be caused by:

    i)   _____

    ii)   _____

    iii)   _____

c)   Normal hotwell level transients associated with power manoeuvres are likely to cause a level alarm. (False / true)

6.   A very low level in the condensate storage tank causes the following operating concern:

_____

_____

_____

7. Considering typical heat sources available for feedheating, fill out the tables below:

a) In the LP feedheaters:

Heat source	Available when ...

b) In the DA and storage tank:

Heat source	Available when ...

c) In the HP feedheaters:

Heat source	Available when ...

8. Extraction steam flow to feedheaters:

a) Is self-regulating and increases with increasing feedwater flow and decreasing inlet feedwater temperature. (False / true)

b) Remains constant as long as steam pressure in the turbine does not change. (False / true)

c) Is controlled by adjusting the feedheater drains outflow. (False / true)

9. Too high a feedheater drains level causes the following adverse consequences and operating concerns:

    a) It can damage the turbine due to _____

    b) It reduces the overall thermal efficiency due to the following effects:

        i) _____

        _____

        ii) _____

        _____

        iii) _____

        _____

        iv) _____

        _____

10. a) Excessively low feedheater drains level may result in equipment damage as follows:

        i) _____

        _____

        ii) _____

        _____

        iii) _____

        _____

        iv) _____

        _____

    b) The overall thermal efficiency is also decreased if:

        i) _____

        _____

        ii) _____

        _____

11. a) Feedheater drains level is normally controlled by adjusting

    _____

b) An abnormally low drains level should trigger the following actions:

i) _____

ii) _____

c) In addition to alarms, a high or very high drains level should cause the following actions:

i) _____

ii) _____

iii) _____

iv) _____

v) _____

vi) _____

d) Upon a very high drains level in a feedheater, the drain valves on the extraction steam piping to this feedheater should (open / close) in order to enhance protection against:

i) _____

ii) _____

12. a) Excluding operating transients, too high a feedheater drains level can be caused by:

i) _____

ii) _____

iii) _____

b) Similarly, causes of abnormally low feedheater drains level are:

i) _____

ii) _____

13. a) Check valves in the extraction steam piping are assisted to close during the following operational upsets:

i) _____ or _____ in order to

_____

ii) _____ in order to

_____

_____

b)   The major operational reasons why these valves have actuators are:

i)   _____

_____

ii) _____

_____

c)   These valves:

i)   Provide adequate isolation to prevent water induction to the turbine. (False / true)

ii)   Can close fully once a high feedheater drains level is detected. (False / true)

iii) Require extraction steam flow to open. (False / true)

14. Suppose that the outlet feedwater temperature from a feedheater bank has dropped below its normal value while operating at a constant unit load. In all the feedheaters in the bank, the drains levels are normal, and a field check confirmed that the extraction steam check valves are fully open.

a)   What is the likely cause of this abnormality?

_____

b)   How can this problem be rectified?

_____

15. a)   Turbine extraction steam flow to the DA is (self-regulated / adjusted by a DA pressure control valve).

b)   Boiler steam flow to the DA is (self-regulated / adjusted by a DA pressure control valve).

16. a)   Steam hammer in the feedheating system can be caused by a rapid drop in the DA pressure as follows:

_____

_____

_____

_____

_____

_____

_____

_____

_____

_____

_____

_____

b) The rapid pressure drop can occur due to failure of prompt

supply of _____

c) Loss of normal DA heating by turbine extraction steam can be
caused by:

i) _____

ii) _____

iii) _____

d) Possible causes of failure of prompt supply of boiler steam to the
DA include:

i) _____

ii) _____

iii) _____

17. a) When high DA pressure, combined with loss of condensate sup-
ply to the DA, persists for more than a few minutes, steam ham-
mer in the condensate system can occur as follows:

_____

_____

_____

_____

_____

_____

_____

_____

b) Loss of condensate supply to the DA can be caused by:

   i) _____

   ii) _____

c) Abnormally high DA pressure can be caused by _____

_____

18. a) Too high a DA level causes the following adverse consequences/ operating concerns:

   i) _____

_____

   ii) _____

_____

   iii) _____

_____

b) When the level is too low, the following adverse consequences/ operating concerns result:

   i) _____

_____

   ii) _____

_____

   iii) _____

_____

19. a) DA level is controlled by adjusting _____

_____

b) At medium and high loads, the following three signals are used to position the level control valve:

_____

c) During startup and at light loads, only the _____

signal is used. This makes the level control (more responsive / sluggish) as compared with its operation at high loads.

20. a)   High DA level should trigger the following automatic actions:

    i) _____

    ii) _____

    iii) _____

    iv) _____

  b)   This upset can be caused by _____

_____

21. a)   Low DA level should trigger the following automatic actions:

    i) _____

    ii) _____

    iii) _____

    iv) _____

    v) _____

  b)   Possible causes of this upset include:

    i) _____

    ii) _____

    iii) _____

22. a)   During unit loading, DA level (decreases / increases / stays constant) because _____

The BLCVs and DA LCVs operate as follows: _____

  b)   During fast unit loading, hotwell level (decreases / increases / stays constant) because _____

_____

_____

_____

_____

_____

_____

The condensate reject and makeup water valves operate as follows:

_____

c) During slow unit loading, hotwell level (decreases / increases / stays constant) because _____

_____

_____

The condensate reject and makeup water valves operate as follows:

_____

23. During unit loading, extraction steam flow (decreases / increases / stays approximately constant) because:

a) _____

_____

b) _____

_____

c) _____

_____

24. The final feedwater temperature changes during turbine loading as follows:

a) Below about 25% FP, it (decreases / increases / stays nearly constant) because:

i) _____

_____

ii) _____

_____

b) Above that power level, it (decreases / increases / stays nearly constant) because:

i) _____

_____

ii) _____

_____

25. a) In the extreme case, exceeding the boiler preheater inlet ΔT limit can have the following adverse consequences:

   i) _____

    due to failure of _____

   ii) _____

    due to failure of _____

  b) Exceeding of the ΔT limit can happen during the following unit operating states:

   i) _____

   ii) _____

   iii) _____

   because _____

_____

_____

_____

_____

_____

_____

_____

_____

_____

26. The following actions should be taken to prevent the preheater inlet ΔT from exceeding its safe limit:

  a) _____

_____

  b) _____

_____

27. When the preheater inlet ΔT is exceeded, the following actions can be carried out in order to return the ΔT to an acceptable range:
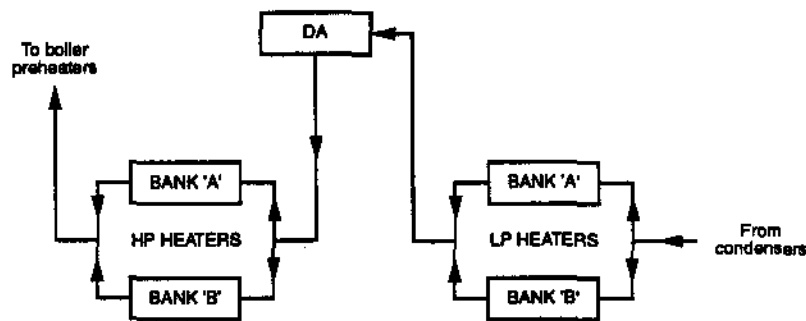
   a) Action: _____

   It reduces the ΔT as follows: _____

   _____

   _____

   b) Action: _____

   It reduces the ΔT as follows: _____

   _____

   _____

28. The following simplified diagram shows the arrangement of feedheaters in a CANDU unit.

   In this system, valving out bank 'A' of the LP feedheaters has the following effects:

   a) The extraction steam and drains flows in bank 'B' of the LP feedheaters (decrease / increase / remain nearly constant) because:

      i) _____

      _____

      _____

      ii) _____

      _____

      _____

   b) The extraction steam flow to the DA (decreases / increases / stays nearly constant) because _____

   _____

c) The extraction steam and drains flows in the HP feedheaters (decrease / increase / remain nearly constant) because _____ .

_____

d) The final feedwater temperature (decreases / increases / stays nearly constant) because _____

_____

29. In the same system of feedheaters as illustrated in question 28, isolation of feedwater flow through bank 'B' of the HP heaters has the following effects:

a) The extraction steam and drains flows in the LP feedheaters (decrease / increase / remain nearly constant) because _____

_____

b) The extraction steam flow to the DA (decreases / increases / stays nearly constant) because _____

_____

c) The extraction steam and drains flows in bank 'A' of the HP feedheaters (decrease / increase / stay nearly constant) because

_____

_____

d) The final feedwater temperature (decreases / increases / stays nearly constant) because _____

_____

30. Any loss of feedheating decreases the unit thermal efficiency because:

a) _____

_____

_____

b) _____

_____

_____

c) _____

_____

31. When some feedheaters are isolated, generator output is affected as follows:

    a) In the reactor leading mode of operation:

_____

_____

    b) In the reactor lagging mode of operation:

_____

_____

_____

_____

32. Removal of too many feedheaters from service may force some unit derating due to the following reasons:

    a) _____

_____

_____

_____

    b) _____

_____

_____

_____

    c) _____

_____

_____

33. a) The IUFWT is required to operate in the event of _____.

_____

    b) The IUFWT operates as follows: _____

_____

_____

_____

APPROVAL ISSUE

    c)   The flow capacity of the IUFWT is about ___% of the full power feedwater flow of one unit.

34. a)   The simultaneous unavailability of the auxiliary BFP and the IUFWT creates a hazard of immediate damage to the unit. (False / true)

    b)   If neither the auxiliary BFP nor the IUFWT can be returned to service within the time limit on their sustained unavailability, the operator must _____

_____ in order to _____

_____

_____

_____

35. a)   In the event of a total loss of all possible long-term sources of treated feedwater, boilers can be supplied with cooling water by one or both of the following systems (depending on the station):

       i)   _____

      ii)   _____

    b)   Boiler pressure must be _____ before either system can feed cooling water to the boilers.

    c)   The operational problems that make these systems the least preferable emergency heat sink for the reactor are:

       i)   _____

_____

      ii)   _____

_____

36. a)   Water hammer can be caused by the following improper pump startup techniques:

       i)   _____

      ii)   _____

    b)   These techniques promote water hammer because _____

_____

_____

_____

37. Inadequate draining of the extraction steam and boiler steam to the DA lines can result in water hammer because _____

_____

38. Severe steam hammer can be caused by condensation of steam pockets in the condensate/boiler feed system.

    a)   The pockets can be formed during the following operating upsets (other than loss of DA pressure control):

        i)   _____

                _____

                _____

        ii)   _____

                _____

    b)   The pockets recondense when _____

_____

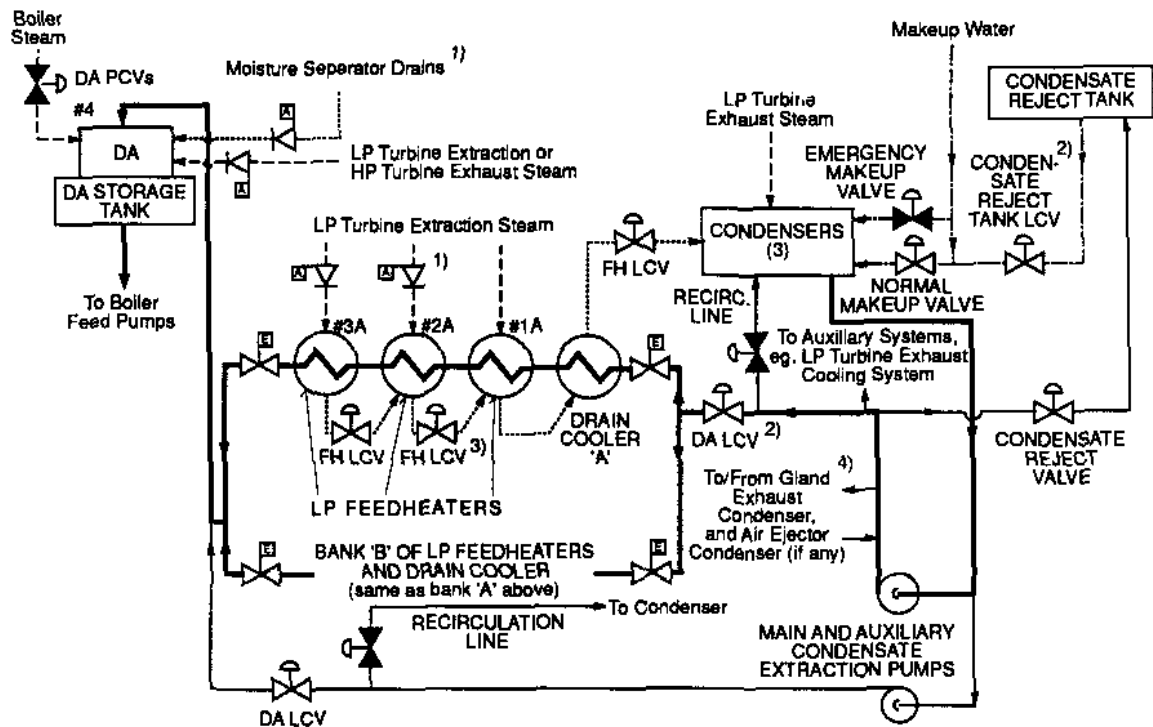   c)   When this happens, violent steam hammer can occur due to

_____

Before you move on to the next module, **review the objectives** and make sure that you can meet their requirements.

Prepared by:	J. Jung, ENTD
Revised by:	J. Jung, ENTD
Revision date:	June, 1994

a) The Condensate and Its Auxiliary Systems

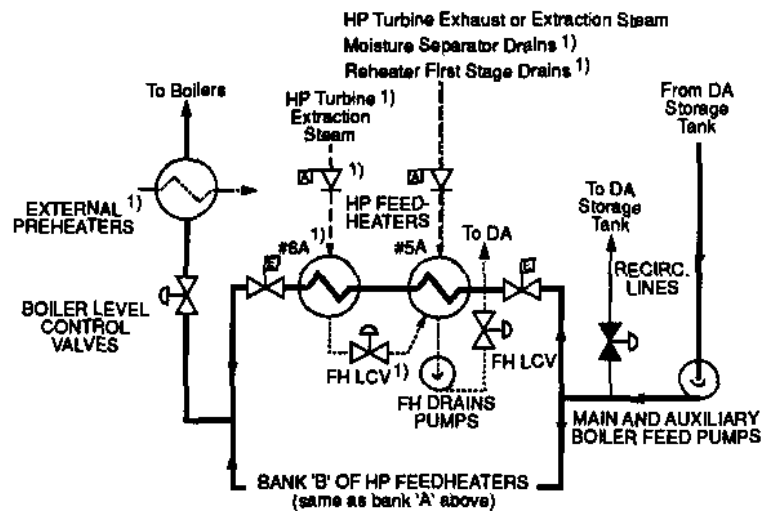## b) The Boiler Feed and Its Auxiliary Systems

Fig. 6.10. Simplified feedheating system of a typical CANDU unit:

DA LCV = Deaerator Level Control Valve;
DA PCV = Deaerator Pressure Control Valve;
FH LCV = Feedheater Drains Level Control Valve;

1) = Not in all stations;
2) = In some units, the valve location is different;
3) = In some units, these drains are pumped into the main condensate line between heaters #1A and #2A;
4) = In some stations, these condensers get the full condensate flow.

Numbers in brackets indicate the number of equipment installed.

———— Condensate/Feedwater   —··—··—— Makeup Water

··············· Drains   —————— Steam   —·—··—··— HT D_2O

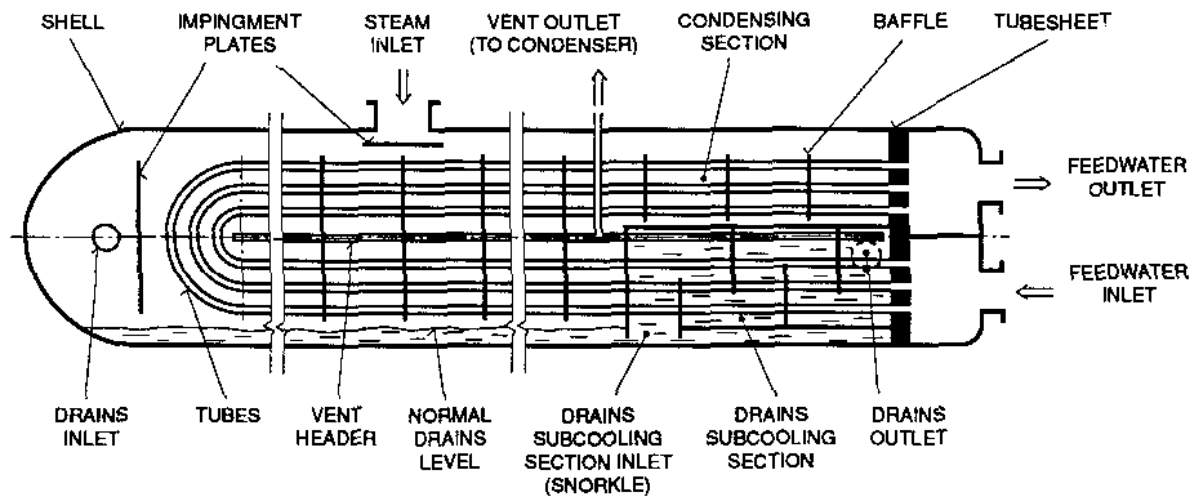**Fig. 6.11. Simplified horizontal U-tube feedheater.**
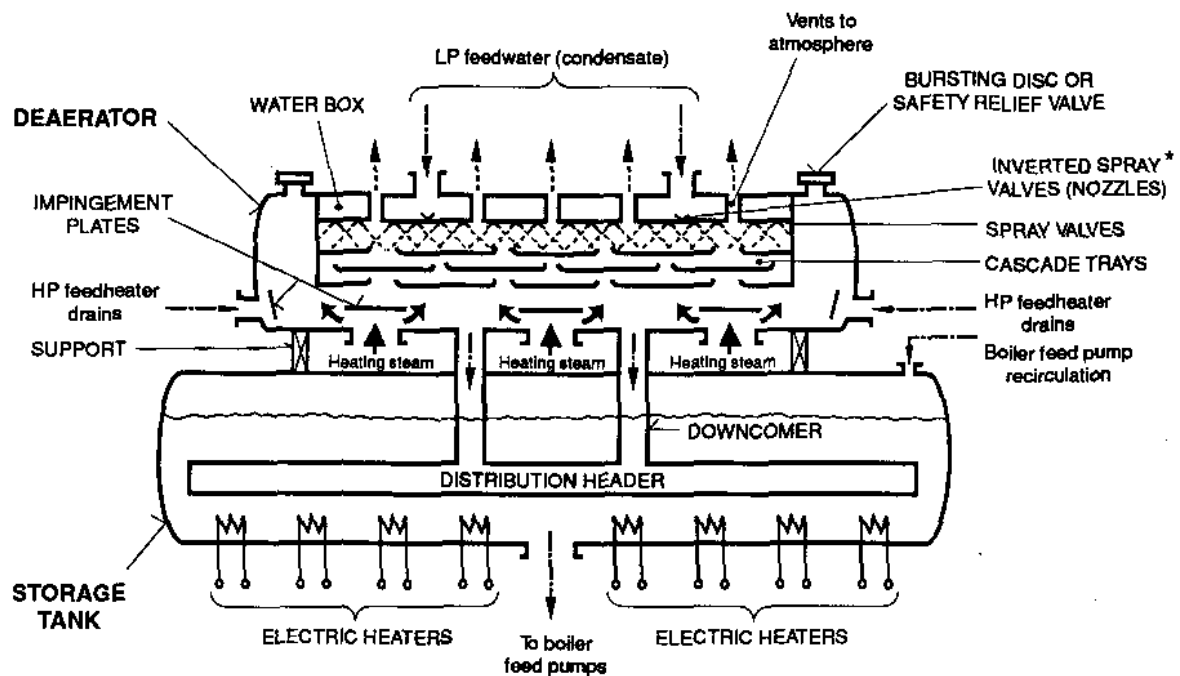
Fig. 6.12. Simplified deaerator and storage tank assembly:

——— Steam   —·—·— Water   ·········· Liberated gases/steam mixture

* Not in all stations.