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Level Control Guide for Feedwater Heaters, Moisture Separator/Reheaters, and Other Equipment

Technical Report

Plant Maintenance Support

Reduced Cost

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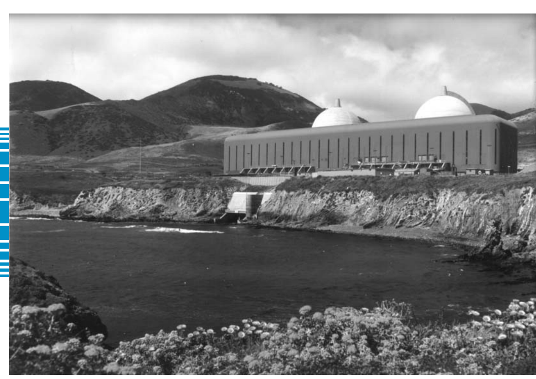

NMAC

Level Control Guide for Feedwater Heaters, Moisture Separator/Reheaters, and Other Equipment

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Final Report, December 2002

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REPORT SUMMARY

Background

In 2001, EPRI NMAC conducted a survey of unplanned capacity loss factors in nuclear power plants. The survey identified the failure of control valves as the number six cause (out of 12) of such losses. Control valves used to control feedwater heater (FWH) levels and moisture separator/reheater (MSR) drain tank levels contributed to this ranking. To address this issue, an additional survey was completed on areas not previously addressed by EPRI documents. It was determined that *Control Valve Guidelines* (EPRI, 1994, TR-102051R1) and *Feedwater I&C Maintenance Guide* (EPRI, 1995, TR-105663) provided a discussion of the control valve proper and, to some extent, a number of accessories. What appeared to be missing was information on the dynamics of FWHs and MSR drain tanks, as well as the appropriate strategies for level control in general and in FWHs and MSR drain tanks in particular.

Objectives

- To help power plant maintenance personnel understand the basic principles of level control for FWHs, MSR drain tanks, and other equipment
- To provide technical information to plant maintenance personnel on establishing proper level and level controller tuning
- To provide technical information on managing FWH level and MSR drain tank level requirements, managing FWH level for reliability and efficiency, and troubleshooting FWH level control problems

Approach

A detailed review of industry literature, product information, and standards was conducted to identify the various designs, applications, and maintenance practices associated with level controllers, moisture separator/reheaters, and feedwater heaters. Utility and industry failure databases were surveyed to determine specific problems and commonly encountered failure mechanisms. Based on this information, recommendations were made on proper tuning, condition monitoring/preventive maintenance, and troubleshooting.

Results

This guide provides information to personnel involved with level control of feedwater heaters, moisture separator/reheaters, and other equipment. It includes information on the principles of level control instruments and level controller operation, level control tuning, feedwater heater and moisture separator/reheater drain tank level requirements, managing feedwater heater level for reliability and efficiency, and troubleshooting feedwater heater level control problems. It provides insights to experienced personnel as well as basic information, guidance, and

instructions to less-experienced personnel assigned to the maintenance and operation of feedwater heaters and moisture separator/reheaters.

EPRI Perspective

Level control, particularly for feedwater heaters and moisture separator/reheater drain tanks, continues to be a challenge to reliable plant operations. This guide provides the tools necessary to understand the special characteristics of level control tuning and the particular challenges posed by level control of the water/steam interface in these feedwater heater and moisture separator/reheater drain tanks. It also provides steps for managing levels for feedwater heater and moisture separator/reheater drain tanks for reliability and efficiency.

Keywords

Level control
Feedwater heater
Tuning
Maintenance
Reliability
Troubleshooting

ACKNOWLEDGMENTS

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Larry Porter	TMI

NMAC and the TAG were supported in this effort by

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ABSTRACT

This guide was developed in response to the relatively high number of unplanned capacity losses in power plants caused by feedwater heater and moisture separator/reheater level problems. It provides basic information on level control to utility personnel responsible for the operation and maintenance of feedwater heaters, moisture separator/reheaters, and other equipment.

This guide includes information on the principles of level control instruments and level controller operation, level control tuning, feedwater heater and moisture separator/reheater drain tank level requirements, managing feedwater heater level for reliability and efficiency, and troubleshooting feedwater heater level control problems. It provides insights to experienced personnel as well as basic information, guidance, and instructions to less-experienced personnel assigned to the maintenance and operation of feedwater heaters and moisture separator/reheaters.

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1.1 Background

In 2001, EPRI NMAC conducted a survey of unplanned capacity loss factors in nuclear power plants. The survey identified the failure of control valves as the number six cause (out of 12) of such losses. Control valves used to control both feedwater heater (FWH) level and moisture separator reheater (MSR) drain tank level contributed to this ranking. To address this issue, an additional survey of areas not previously addressed by EPRI documents was completed. It was determined that *Control Valve Guidelines* [31] and *Feedwater I&C Maintenance Guide* [6] provided a discussion of the control valve proper and, to some extent, a number of accessories. What appeared to be missing was information on the dynamics of FWHs and MSR drain tanks as well as appropriate strategies for level control in general and in feedwater heaters and drain tanks in particular.

1.2 Guideline Development

This guide is a synthesis of two guidelines originally planned: 1) level controllers/level loop troubleshooting and 2) feedwater heater and moisture separator/reheater level control. As the guidelines were developed, it became increasingly obvious that there was considerable duplication, and that feedwater heater level control was a special case within the overall scheme of level controllers/level loop control. Therefore, at the Task Advisory Group meeting of August 27-28, 2002, the guidelines were combined.

1.3 Guideline Approach

This guide is intended to follow a logical path, beginning with the components of a level loop, then level loop tuning. This is followed by an introduction to the feedwater system, a feedwater heater and moisture/separator component overview, operating aspects of the FWH and MSR, and setting the right level in this equipment. The guide concludes with managing level for efficiency and reliability and a section on troubleshooting feedwater heater level control problems.

1.4 Highlighting of Key Points

Throughout this report, key information is summarized in “Key Points.” Key Points are bold lettered boxes that succinctly restate information covered in detail in the surrounding text, making the key point easier to locate.

The primary intent of a Key Point is to emphasize information that will allow individuals to take action for the benefit of their plant. The information included in these Key Points was selected by NMAC personnel, consultants, and utility personnel who prepared and reviewed this report.

The Key Points are organized according to the three categories: O&M Costs, Technical, and Human Performance. Each category has an identifying icon, as shown below, to draw attention to it when quickly reviewing the guide.

Key O&M Cost Point

Emphasizes information that will result in reduced purchase, operating, or maintenance costs.

Key Technical Point

Targets information that will lead to improved equipment reliability.

Key Human Performance Point

Denotes information that requires personnel action or consideration in order to prevent injury or damage or ease completion of the task.

Appendix F contains a listing of all key information in each category. The listing restates each Key Point and provides reference to its location in the body of the report. By reviewing this listing, users of this guide can determine if they have taken advantage of key information that the writers of this guide believe would benefit their plants.

1.5 Glossary

A glossary of terms used in this guideline is contained in Appendix A.

2
DESCRIPTION OF LEVEL LOOP COMPONENTS

2.1 Purpose

To begin the discussion of level control, this section provides an overview or primer of the level loop and the components that make up the loop, including level sensor/transmitters, controllers, and control valves. Particular attention will be given to pneumatic controllers, which still find wide application in many level control processes. This overview does not replace the manufacturer-supplied, technically accurate service manual, but is intended to aid in understanding the construction, operation, and calibration of transmitters and controllers. This section may be skipped by the experienced individual who has training in level loop components and their design.

2.2 Level Control Process Description

A level control process is shown in Figure 2-1. This example is probably the most common configuration found in a power plant. The tank level depends on the difference between the flow-in and the flow-out. The flow-in is considered the *load* since it is the changes in flow-in that must be responded to in order to maintain level. To respond to these changes, the flow-out must be changed correspondingly to maintain the tank level. This is done by a control loop. To better understand this control loop, the schematic of Figure 2-1 is converted to a block diagram as shown in Figure 2-2.

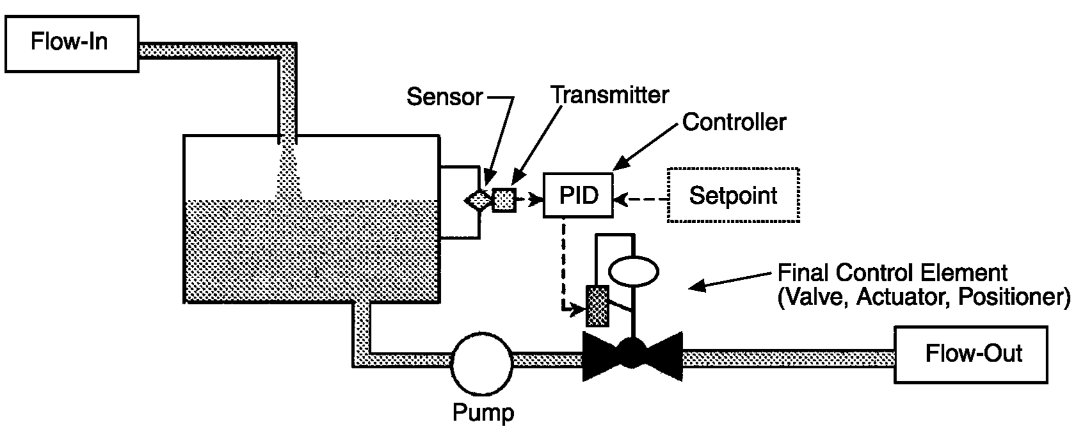

Figure 2-1
Level Control Process Schematic

The control of the flow-out depends on the tank level. This is accomplished by sensing the tank level and then sending this level signal to a controller, where it is compared to a setpoint. If the actual level and the desired level are not the same, an error is generated (either positive or negative depending on whether the tank level is high or low), and this error is processed by the controller. This processing may be a mechanical and/or electrical process. The controller output is a signal to the control valve or final control element to correct the error without causing additional problems such as instability.

The control loop terminology to be used in the remainder of this report is shown in Table 2-1, and a glossary of these and other terms appears in Appendix A.

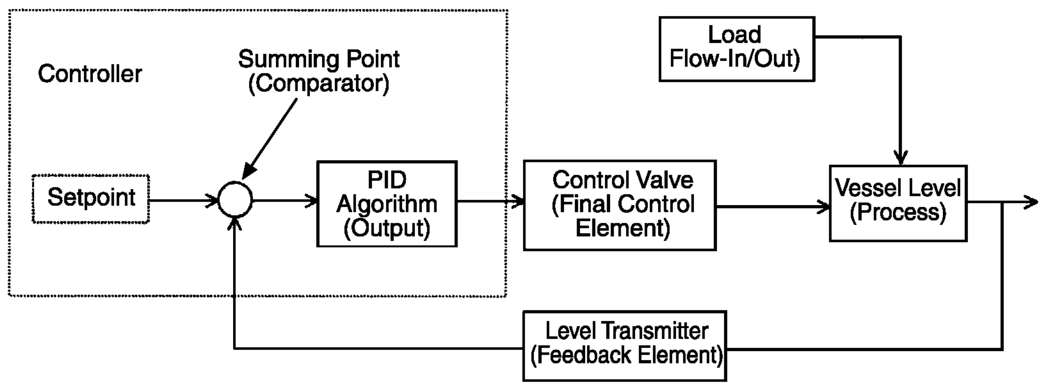

Figure 2-2
Level Control Loop Block Diagram

Table 2-1
Control Loop Terminology

Terminology	Physical Representation
Controlled variable	The tank level (sometimes called the *process variable (PV)*).
Manipulated variable	Flow-out (sometimes referred to as the *controller output (CO)*).
Setpoint	The (*electrical equivalent of the*) desired tank level.
Summing point	Where (*the electrical equivalents of)* the actual tank level (from the transmitter) and the setpoint are compared. Sometimes called a *comparator.*
Feedback element	The level transmitter
Disturbance	Flow-in. (sometimes called the *load.*)
Error	The output of the summing point.

2.3 Level Transmitter

The loop component description begins with the level transmitter. In most cases of level detection, exactly where the "sensing" leaves off and the "transmitting" begins is not clear. Therefore, the level sensor and transmitter will be treated as a single device and referred to as the level transmitter. The level transmitter functions by using some physical property of a liquid to provide the location of the surface of the liquid. The following types of level transmitters are used in nuclear power plants:

- *Head pressure*: The height of the liquid is proportional to the pressure at the bottom.
- *Displacer (*or *float*): The buoyancy of an object provides feedback to a transducer proportional to the height of the liquid.
- *Bubbler* (or *purge*): The amount of air pressure required to cause air to exit the submerged end of a tube at a given rate (in bubbles per unit of time) is proportional to the height of the liquid above the end of the tube.
- *Ultrasonic*: The distance to the top surface of the liquid is proportional to the time it takes to reflect a high-frequency sound wave back to the transceiver.

Head pressure, displace, and bubbler types of level transmitter are based on fluid weight and therefore are sensitive to fluid density. This factor can come into play during either calibration or operation. If the fluid is to operate at ambient conditions, then calibration at ambient conditions will normally be sufficient.

2.3.1 Head Pressure

The head pressure type is the most common type of level transmitter used in a power plant. It is found everywhere from steam generators and reactor vessels to storage tanks for condensate and diesel oil. It is based on the principle that the differential pressure between the top of the fluid and the bottom of the fluid is proportional to its height. When the fluid being measured is in a vessel that is open to the atmosphere, a simple arrangement, such as the one shown in Figure 2-3, works quite well.

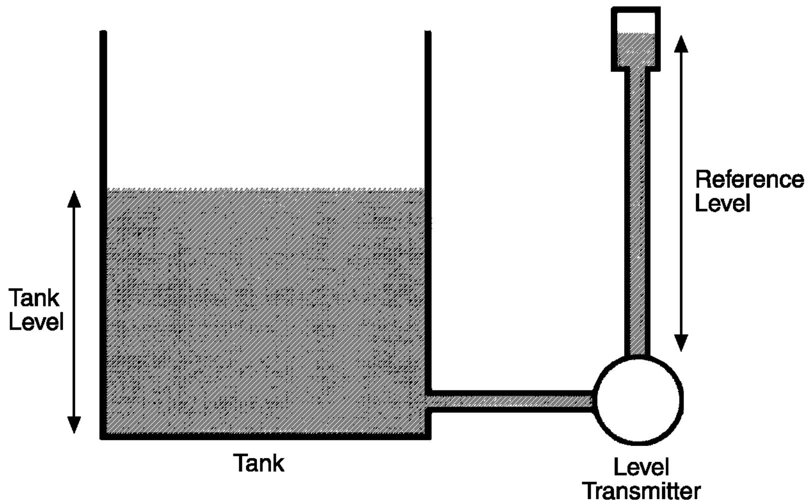

Figure 2-3
Level Measurement in Open Tank With Differential Pressure Transmitter [6]

The level transmitter is connected to the bottom of a *reference leg* and measures the differential pressure between the height of the liquid in the tank and the reference leg. This type of leg is called a *wet leg* since it is filled with the process liquid. The level would be determined using the following formula:

$$\Delta P = [L_{ref} \times \gamma_{ref}] - [L_{\text{tank}} \times \gamma_{\text{tank}}] \qquad \textbf{Eq. 2-1}$$

where,

L_{ref} = height of liquid in the reference leg

γ_{ref} = specific weight of liquid in the reference leg

L_{tank} = height of liquid in the tank

γ_{tank} = specific weight of liquid in the tank

Two relationships are of note:

- The tank level and differential pressure are inversely related, i.e., maximum differential pressure occurs at minimum tank level.
- The differential pressure is dependent on the specific weights (γ, also known as density) in the reference leg and tank. Usually these densities will be the same, since the fluids are typically the same in both; in a properly designed system, the fluids in both will be at the same temperature. However, if there is a temperature difference, their specific weights may differ significantly enough to invalidate calibration.

A variation of the wet leg is the *dry leg*, in which there is no liquid in the leg or, more commonly, no reference leg at all. The measured level would be proportional to the pressure or simply:

$$\Delta P = L_{\text{tank}} \times \gamma_{\text{tank}} \qquad \textbf{Eq. 2-2}$$

Here, technically, the differential pressure is gage pressure, i.e., above atmospheric pressure. The relationships of note would be:

- The tank level and differential pressure are directly related, i.e., maximum differential pressure occurs at maximum tank level.
- The differential pressure is dependent on the specific weight (γ) of the fluid. Therefore, calibration must consider the temperature of the fluid. In fact, this is one of the reasons for using the wet leg, since variations due to temperature in a properly designed system are small.

Where the liquid must be contained, or where the liquid is at saturated conditions, such as in a steam generator, it is necessary to have the top of the reference leg routed back to the tank. This arrangement is shown in Figure 2-4. The measured level is determined using the following formula:

$$\Delta P = [L_{ref} \times \gamma_{ref}] - [L_{\text{tank}} \times \gamma_{\text{tank}}] - [L_{steam} \times \gamma_{steam}] \qquad \textbf{Eq. 2-3}$$

where,

L_{steam} = height of steam in the tank

γ_{steam} = specific weight of steam in the tank

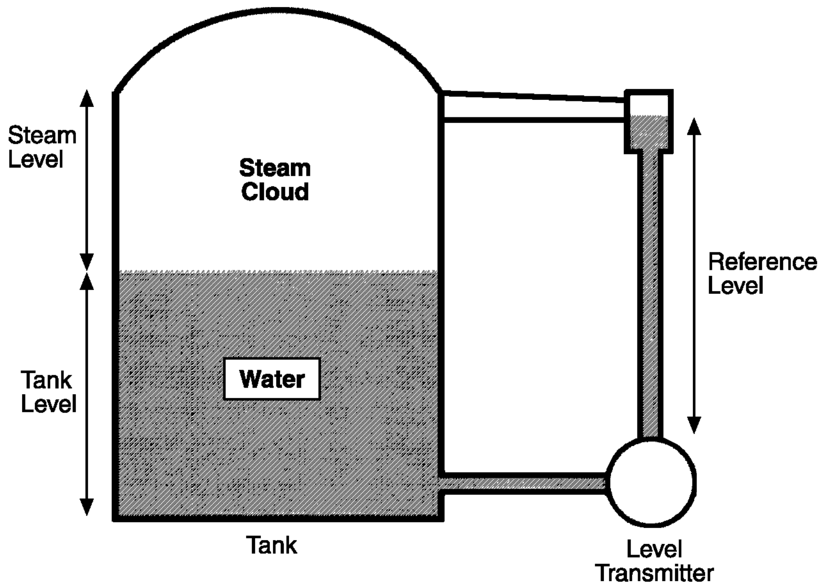

Figure 2-4
Level Measurement in Closed Tank With Differential Pressure Transmitter [6]

For saturated steam at 650°F (343°C), the specific weight of the steam is one-sixth of saturated water. As shown in the expression, this steam weight has an effect on the differential pressure. Any steam higher than the top entrance to the reference leg has an equal effect on both sides of the differential transmitter and can be ignored.

Note that it is important that the liquid level in the reference leg remain constant. For saturated fluids, this can be a challenge. Therefore, vessels of this type will include a condensing pot at the top of the instrument reference leg and upward sloping of the tubing to the pot to ensure that the leg remains filled to the proper level.

2.3.2 Displacer Type

The displacer type of level transmitter finds use primarily in feedwater and condensate systems. Most feedwater heater level transmitters operate using the displacer type. Figure 2-5 shows the basic parts involved: a metal cylinder that is partially submerged in the liquid. The basis for operation is Archimedes' Principle, which states that a body immersed in a liquid will be buoyed up by a force equal to the weight of the liquid displaced. The top of the displacer is attached to a displacer rod, which is in turn attached to a torque tube that is fixed at the opposite end to the controller housing. Therefore, any movement of the displacer in the vertical direction will be resisted by the proportional resistance of the torque tube, i.e., the torque tube acts as a torsional spring. As the liquid level changes, the amount of submergence determines the amount of buoyancy force, tending to move the displacer in the vertical direction; i.e., the greater the submergence, the greater the force, in accordance with Archimedes' Principle. The actual movement of the lever is transmitted to the controller by a torque tube rotary shaft that is concentric to the torque tube and is connected to the end of the displacer rod.

The range of liquid level that can be controlled is determined by the length of the displacer, since the displacer must be submerged but not totally submerged to be effective. (In the latter case, there would be no additional force "available" to cause the displacer rod to move.) Also, since the displacer rod moves from bottom *stop* to top *stop* during the movement of the liquid level, its movement could also be included. (Note that the term *stop* may not be a physical part called a stop, but is meant to reflect the physical limitations on the vertical movement of the displacer rod.) Other factors that will affect the range of measurement are the density of the fluid and the thickness of the torque tube. The density of the fluid determines the buoyancy force (lower density means less level range) and the torque tube thickness controls how much buoyancy force is required to move the displacer rod through the full range of vertical movement. (Level controller manufacturers can provide torque tubes of different thickness.) Density is particularly important in calibration, since the temperature of the fluid used for calibration may not be the same as operational temperature.

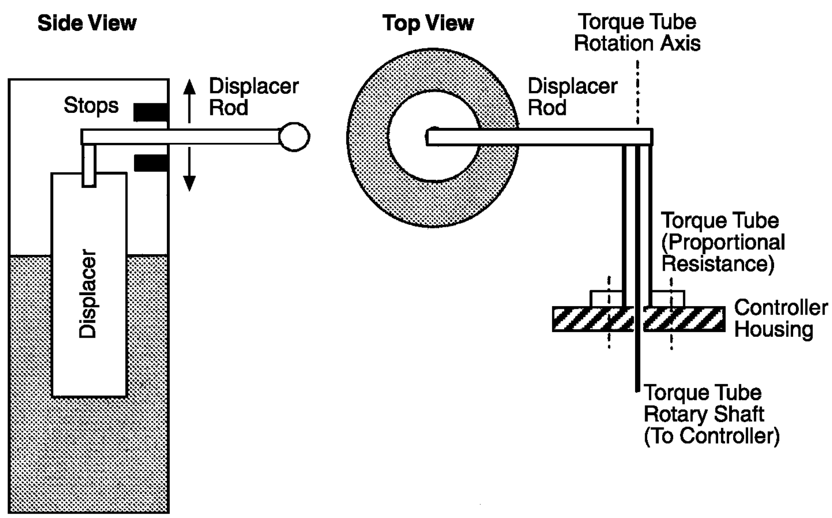

Figure 2-5
Displacer Type Level Transmitter

2.3.3 Bubblers

Measuring liquid level in a vessel can also be accomplished using an air bubbler system, also known as a purge system. A dip tube or standpipe is vertically mounted inside the tank as shown in Figure 2-6. An air source supplies a constant airflow into the pipe, forcing the liquid out of the pipe. The pressure in the pipe is equal to the hydrostatic pressure of the liquid at any level because the excess air will produce a steady stream of bubbles and purge any liquid out of the pipe.

The airflow is maintained by a regulating valve and is set to be slightly greater than the pressure exerted by the maximum level of liquid in the vessel. As level decreases, the hydrostatic pressure decreases and more air bubbles are formed. A gauge measuring the pressure in the pipe is calibrated to display the level based on the fluid's specific gravity and the resulting hydrostatic head developed by the liquid level. In effect, it is simply measuring backpressure.

The bottom of the pipe is kept at least 3 inches (76 mm) from the bottom of the tank to avoid sediment collection. The edge of the pipe is typically notched or beveled to allow for a constant release of small air bubbles. The level below the bottom of the pipe is not detected.

Bubbler systems are well suited to measure the level of liquids that are corrosive or viscous. Temperature changes resulting in density variations affect the accuracy of the indicated level. The pipe may be susceptible to plugging, and any air leaks in the system will cause erroneous level readings. However, the system is simple and low-cost.

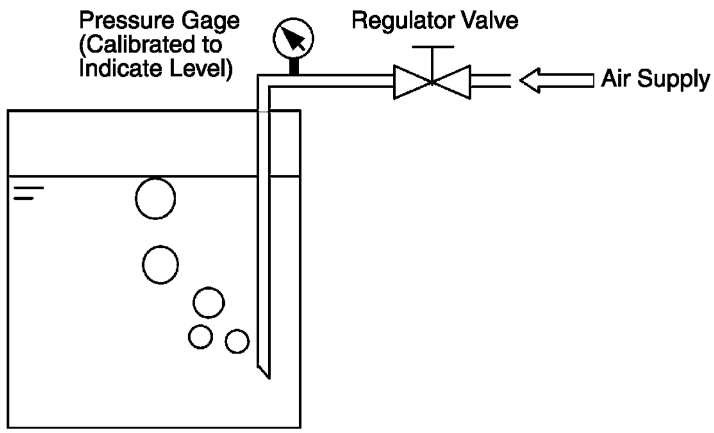

Figure 2-6
Bubbler [22]

2.3.4 Ultrasonic

Ultrasonic level transmitters operate by generating high-frequency sound pulses and measuring the time it takes an echo to return, as shown in Figure 2-7. These devices can be used for both point and continuous level measurement.

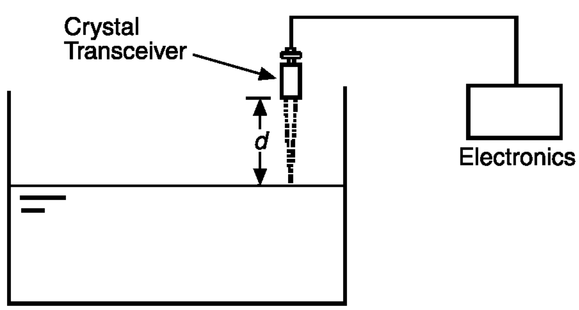

Figure 2-7
Ultrasonic Level Sensor/Transmitter [22]

For continuous measurement, a non-contacting sensor return echo is sent to a microprocessor, which processes the signal into a digital value of the distance between the sensor and surface level. This signal can then be converted to an analog output signal for level indication.

Point measurement for alarm and control functions can be made using a non-contact sensor as described above with specific level switch settings established as desired. More typically, level switch functions use a contact-type sensor. Contact sensors contain an air gap; when liquid enters this gap, the rate of travel of the ultrasonic signal changes. The instrument's circuitry senses this change and operates the associated level switch.

The primary advantage with using ultrasonic level sensors is their ability to measure level without making contact with the process fluid. Their accuracy is unaffected by changes in the fluid such as density, conductivity and dielectric constants. Accuracy to ±0.25% full scale can be obtained for units with temperature compensation. Limitations of these devices would include applications where conditions exist such as high dust, water vapor content, or foamy liquid that could weaken the echo by dispersion or absorption of the signal. Ultrasonic level transmitters are beginning to see use in feedwater heater level measurement.

2.4 Level Controllers

Level controllers can be of three types:

- Pneumatic
- Electronic
- Digital

2.4.1 Pneumatic Controllers

The pneumatic controller is by far the most common used in the nuclear industry. The basic technology is well over 50 years old, having come into widespread use after the publication in 1942 of the seminal paper *Optimum Settings for Automatic Controllers* by J. G. Ziegler and N.B. Nichols [11]. Pneumatic controllers are usually reliable if properly maintained, but this maintenance is comparatively costly compared to electronic and digital controllers. Pneumatic controllers also need an air supply, and there are problems associated with pressure maintenance and cleanliness.

A pneumatic controller is shown in Figure 2-8. Level is received from the *torque tube shaft* (discussed in Section 2.3.2) and applied through a lever fastened at one end of a balance beam called the *beam and flapper*. The balance beam is pivoted between the *proportional bellows* and the *reset bellows*. At the opposite end of the balance beam is a nozzle through which air flows. Variations in nozzle air flow cause changes in nozzle pressure, which in turn controls the flow of supply air through the *relay valve* and hence to the *control valve* diaphragm housing. This flow of supply air also is used to provide feedback through the proportional valve and reset valve to the proportional and reset bellows, which modify the beam and flapper movement, resulting in the appropriate control action. In the following paragraphs, the operation of each of these components is discussed.

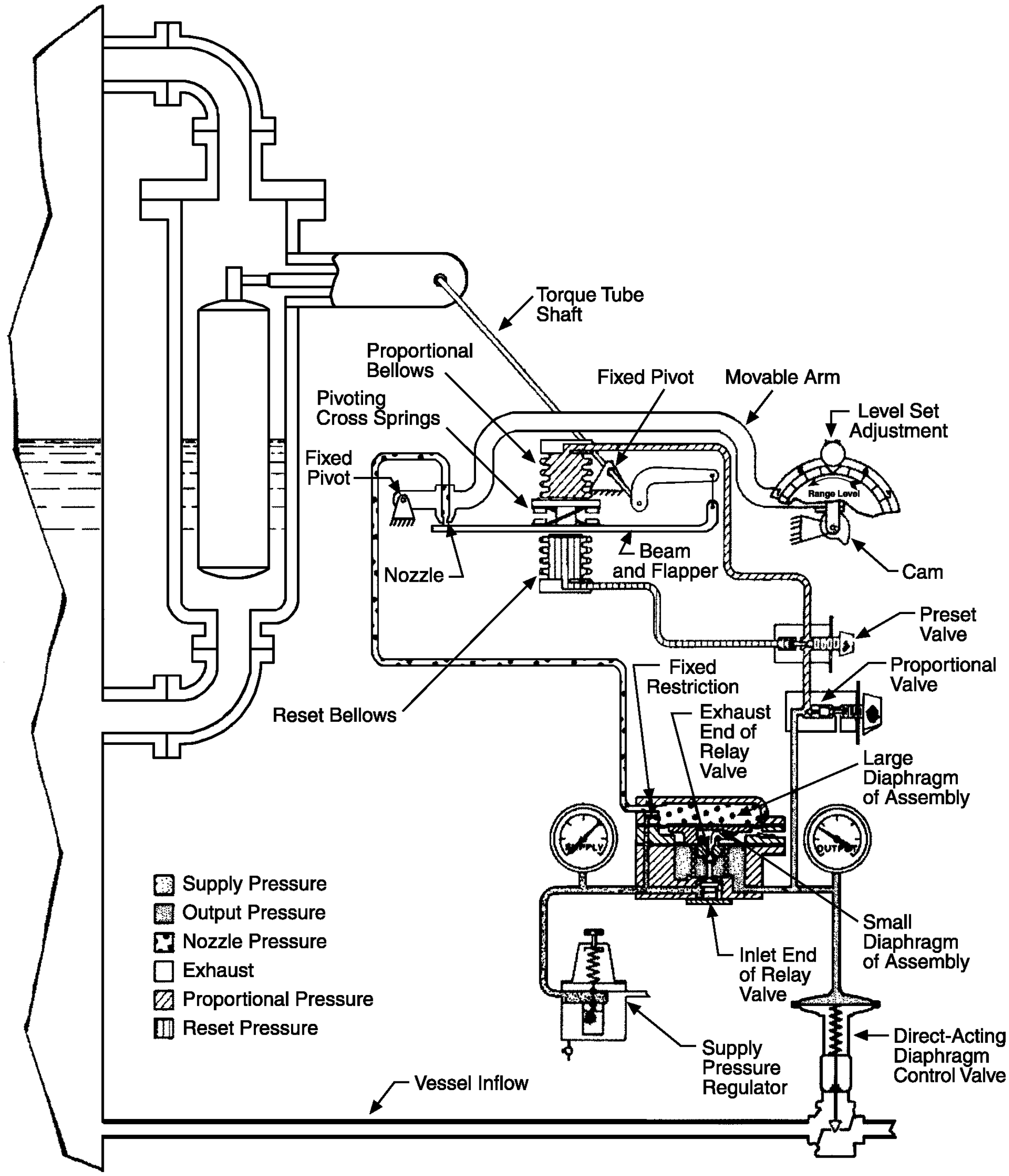

Figure 2-8
Pneumatic Controller [17]

2.4.1.1 Nozzle-Flapper/Relay Valve

Referring to Figure 2-9, air is supplied by pressure (P_s), passes through a fixed orifice, and pressurizes a chamber. The chamber pressure is controlled by the amount of air that leaks through the nozzle. The larger the amount of leakage, the lower the pressure in the chamber. The leakage is determined by the distance between the nozzle and the flapper; the greater the distance, the greater the leakage. Therefore, movement of the flapper results in a change in the chamber pressure.

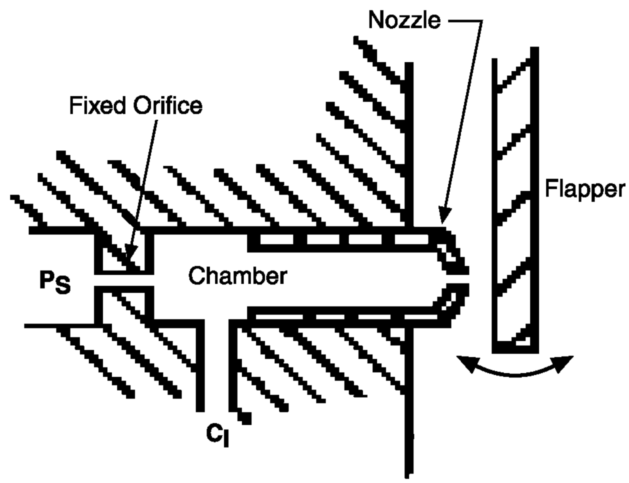

Figure 2-9
Nozzle Flapper

This backpressure is sensed through a line (C_1) that is used to control another pneumatic device. Through this action, the nozzle-flapper converts a mechanical motion to a pneumatic signal and, because of the sensitivity of the pressure to the position of the flapper, also acts as a mechanical amplifier.

In Figure 2-8, supply air from the *regulator* enters the *relay valve*, where it passes through a *fixed restriction* or fixed orifice as discussed for Figure 2-9, and enters a chamber that is just above the *large diaphragm of assembly*. The outlet of the chamber is connected to the *nozzle*. Therefore, as the flapper position varies, the pressure within the chamber varies and causes the *large diaphragm of assembly* to move up and down. Figure 2-10, while not identical to the image of the *relay valve* in Figure 2-7, illustrates how this action controls the airflow to the *direct acting diaphragm control valve (air-to-close)*.

The purpose of the *relay valve* is to amplify airflow. While the control pressure from the nozzle/flapper would in fact move the control valve diaphragm, the airflow would be so small that response times would not allow proper control. The relay valve is a volume booster or amplifier.

The design of a relay valve is quite similar to a pressure regulator, except that the chamber pressure force replaces the spring force. The *large diaphragm of assembly* moves vertically in response to changes in chamber pressure. With no pressure in the chamber, the diaphragm is fully up so that the upper valve is open. If there is any pressure in the valve air operator, it will pass up through the upper valve and out the vent. When the chamber pressure increases, the large diaphragm of assembly moves down, closing the upper valve. As soon as it closes, it begins to open the lower valve through a stem that connects the upper and lower valves. This allows air to pass through the lower valve to the control valve. Eventually the pressure under the diaphragm builds up as the downstream piping, valve, etc. pressurize and push it back up, allowing the spring under the lower valve to close the lower valve.

Note that in the relay valve shown in Figure 2-10, the diaphragm area above the large diaphragm of assembly is approximately equal to the area underneath, so the *control pressure to the valve* is maintained equal to the *control pressure from nozzle/flapper*. The means that there is a pressure gain of one. By varying the ratio of the areas in the design, other pressure gains are possible.

2.4.1.2 Processing of Level Input

Note that the torque tube shaft in Figure 2-8 is connected through a rotating pivot point to a lever arm that is in turn is free to move one end of the *beam and flapper*. As the displacer moves up, it causes the lever arm to rotate clockwise, rotating the beam and flapper around the *pivoting cross springs,* thus closing the space between the flapper and nozzle. This increases the pressure in the relay valve (and thus the control valve actuator) and the valve begins to close. Since the valve is controlling flow into the vessel and the level is increasing, the valve responds correctly by lowering flow. When the displacer moves down, the opposite actions occur.

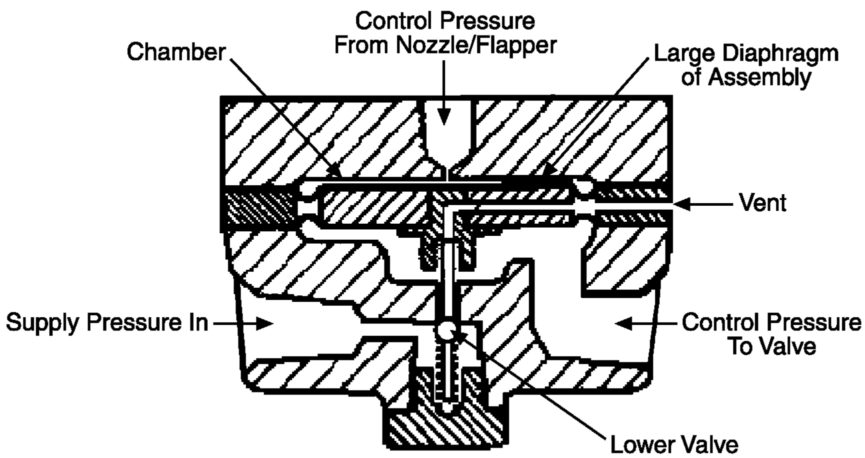

Figure 2-10
Relay Valve

2.4.1.3 Setpoint Adjustment

The easiest way to understand how level setpoint is adjusted is to follow the actions that take place when the *level set adjustment* is changed in Figure 2-8. As the adjustment lever is moved, it causes a cam to rotate, which in turn moves the *movable arm.* This changes the nozzle position relative to the flapper. If this action moves the nozzle away from the flapper, the control valve opens allowing increased flow and causing the level to rise. As the level rises, the displacer rises, causing the lever arm to rotate down and the flapper to move up. When the nozzle/flapper gap returns to the starting position, the control valve is at its initial position with the level at a new point. The opposite action occurs when the movable arm moves the nozzle toward the flapper.

2.4.1.4 Proportional Control

As noted in Section 2.4.1, the bellows in Figure 2-8 (along with the reset bellows which is discussed next) form the pivot for the beam and flapper. If the pivot moves up and down, it will also move the flapper toward or away from the nozzle. Note that the bellows is supplied by the *control pressure to valve pressure*. Therefore, if the flapper moves up, increasing the chamber pressure, the bellows pressure will also go up. This will cause the bellows to expand and move the flapper down, countering the original movement. The opposite action occurs when the nozzle moves down, away from the flapper. Therefore, the *proportional bellows* counteract the response to the original movement. Since the nozzle flapper moves the most if the bellows moves little or not at all, low pressure in the bellows allows a large initial movement of the flapper. As the nozzle/flapper is a mechanical amplifier, this large initial movement results in high gain. The pressure is controlled by using the *proportional valve*. This is a three-way valve in which part of the flow goes to the bellows and part is vented. The smaller the amount that is vented, the greater is the pressure delivered to the bellows and the lower the amount of flapper response, and therefore the gain is smaller. This pressure is roughly proportional to the amount delivered to the control valve.

2.4.1.5 Reset Control

As will be discussed later in this guide, integral (or reset) control is added to a control scheme in order to eliminate the problem of offset. Offset is difference between the operating point and the setpoint. It is the result of a process operating at a load different than when the set point was entered. Offset can be minimized by setting the gain high, but at a cost to stability during transients.

However, if the gain could be turned down momentarily during a transient and then returned to a high value during steady state operation, offset can be minimized acceptably (but never completely), without instability. In the pneumatic controller, this is what the *reset bellows* does. As seen in Figure 2-8, the reset bellows forms the other half of the beam and flapper pivot. It is supplied by part of the air that goes to the proportional bellows. The reset bellows air supply also contains an adjustable valve. Unlike the proportional valve, the reset valve serves only to restrict flow. Therefore, when the control system is in steady state operation, the pressures in both the *proportional bellows* and *reset bellows* are equal and the pivot point is at rest and “centered.” When a level change causes the nozzle/flapper/relay valve to change the control pressure, the proportional bellows immediately responds to limit the effect (control gain) by moving the pivot point. It is able to do this because the pressures in the two bellows are now different. However, as the pressure in the *relay bellows* begins to change, it nullifies this pressure difference and the pivot point position moves back to its original location. The rate at which it does this is controlled by the reset valve. Therefore, gain is high during steady state operation, but when a transient occurs, the gain is “turned down” for a period determined by the reset valve. After the transient, the gain is returned.

2.4.1.6 Bourdon Tube Variation

While all pneumatic controllers use a nozzle/flapper arrangement, some variations occur in providing response control. The most common is the use of a bourdon tube to provide proportional control. As with the use of the bellows, the objective is to be able to use the variation in the nozzle/flapper pressure to control the valve movement through a relay while providing some way to vary the response, i.e., the gain.

Figure 2-11 shows the bourdon tube and the pneumatic controller is shown in Figure 2-12. The nozzle/flapper pressure is used to control the relay valve position. This tube has an inner and outer channel. Air is supplied at one end of the inner channel and is regulated at the other end using the nozzle/flapper principle. Therefore, the pressure in the channel varies with the flapper position, which is connected to the end of the torque tube and therefore reflects level. As with all bourdon tubes, an increasing pressure causes the tube to straighten. So if the flapper moves toward the bourdon tube nozzle, the bourdon tube will start to move away, tempering the pressure increase. However, the amount of movement is not controlled. To achieve that control, a second channel is provided in the tube. It is connected to the output of the relay valve through a proportioning valve as in the bellows arrangement above. When the flapper moves toward the nozzle, the output of the relay valve pressurizes the outer channel, adding further amounts of straightening and adding to the original movement. By adjusting the proportional valve, the amount of response movement is controlled and therefore gain adjustment is achieved. Note that there is no reset function using a bourdon tube. To counter the proportional effect would require some way to reverse the action of the bourdon tube, which is not practical.

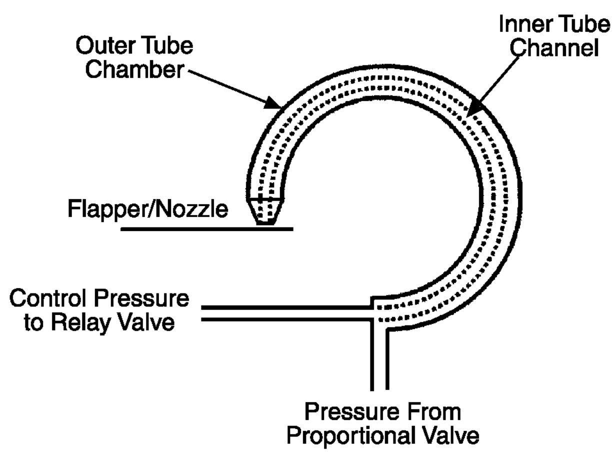

Figure 2-11
Bourdon Tube Variation for Proportional Feedback

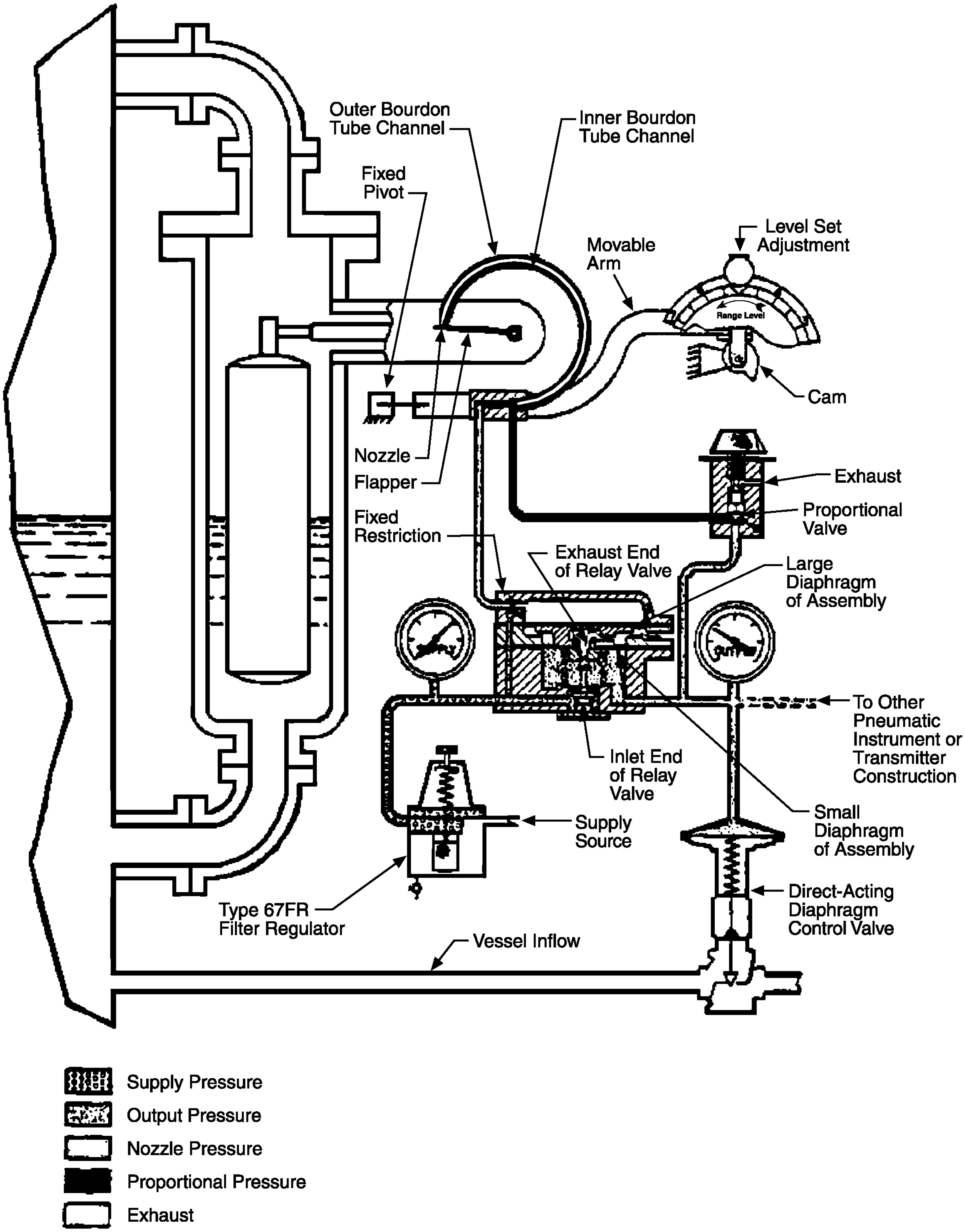

Figure 2-12
Pneumatic Controller Using Bourdon Tube for Proportional Control [18]

2.4.2 Electronic Controllers

Electronic controllers have been slowly replacing pneumatic controllers; but in the future, they will no doubt be displaced by digital controllers as the replacement of choice. The electronic controller uses discrete components (resistors, capacitors, operational amplifiers, etc.) to process the level input signal electronically. This means that the level signal can be taken from a differential pressure transmitter arrangement, such as in Figures 2-1 or 2-2, and processed directly to solve the standard controller algorithm and provide an output to the control valve through an I/P or E/P transducer. Electronic controllers have distinct advantages over pneumatic controllers:

- Electronic controllers allow selection of any level measurement device that can produce an electrical signal. This has distinct advantages over displacer-type controllers, which require special mounting and supporting equipment.
- They eliminate much of the pneumatic tubing that provides its own set of maintenance problems.
- They allow much faster response because it is electronic.
- They allow a much broader range of controller tuning options. (Tuning will be discussed in the next section.)

Electronic controllers also have some distinct disadvantages that may make them difficult to satisfactorily apply. For example:

- Problems with radio frequency noise cause by communication devices
- Component aging, e.g., capacitors
- Electrical static problems with operational amplifiers

2.4.3 Digital Controllers

Digital controllers have been around for more than a decade. Nevertheless, their preference over pneumatic devices is still not widespread in the nuclear industry, despite the advantages that they offer. These include:

- Faster response time
- Higher accuracy
- Greater range of proportional and integral adjustment capability
- Automatic control of level setpoint for various operating conditions
- Remote control of setpoint
- Capability to collect, store, and trend process data for performance tracking and condition monitoring

Setting up a digitally controlled level process has no single approach and will depend on existing plant design as well as the reason for changing. It requires careful selection of components and equipment as well as careful evaluation that the system will perform as designed. Some things that need to be considered are:

- Potential for system failure due to software problems
- Potential effects of electromagnetic interference, e.g., communication transceivers
- Potential for errors and/or unauthorized changes to software
- Training and procedure changes

Component selection can involve buying a complete package that replaces, on a one-for-one basis, existing equipment, e.g., a level controller with digital level measurement and digital microprocessor with a PI algorithm. Alternatively, it can be an "assembly required" approach where the discrete components are purchased, for example, a digital level transmitter that feeds a separate digital controller with multitude of algorithms from which to pick.

Additional discussions regarding digital upgrades may be found in *I&C Upgrade—Implementation Experience and Perspective* [19].

3
LEVEL LOOP TUNING

3.1 Introduction

Section 2 described the components of a control loop and then focused on those particular to the level loop. This section carries on from that description and covers the tuning of level loops. It begins with the purpose of loop tuning, covers tuning methods (both manual-based and model-based), and then focuses on the difficulties of controlling level—because it is a non-self-regulating process, i.e., inherently unstable, and therefore requires a different tuning approach. In particular, it has a greater tendency to become unstable when subjected to integral action of a PID controller. Recommendations are then discussed on how to tune a level control process, including the use of differential action to improve performance and the need for filtering if the level signal is noisy.

3.2 Purpose of Loop Tuning

3.2.1 Stability

Tuning is the determination of the proper controller settings that will cause the loop to function as designed. The ultimate goal of a tuning method is to provide satisfactory process control without the process becoming unstable. Stability is measured by observing how the process variable (PV) decays to its final value after a disturbance is introduced and the control system responds. The most common criterion used in tuning is referred to as the quarter wave damping ratio. After the controller settings are established, the loop is placed in automatic, and a disturbance is introduced, e.g., a set-point change, and the PV is observed. As the PV goes to its new value, it should do so (within reason) in a way shown in the left panel of Figure 3-1.

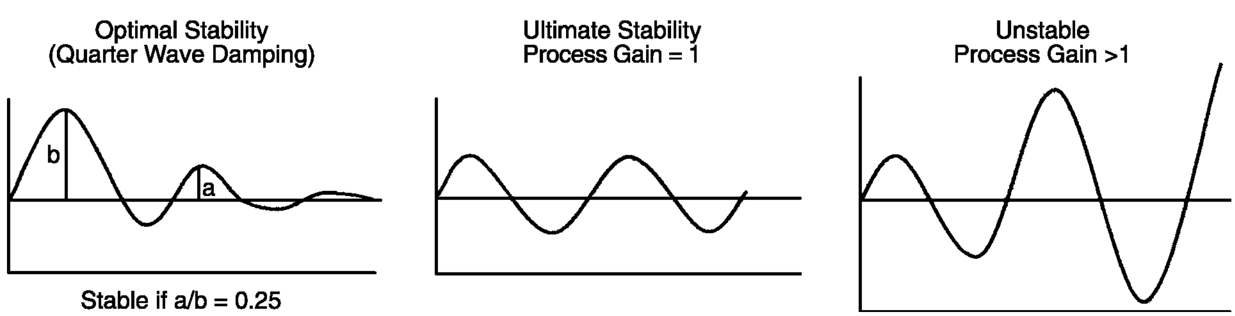

Figure 3-1
Process Stability

The *damping ratio* is defined in this guide as the ratio of first peak value to the next peak value as the PV settles to its final value. This is illustrated in the left panel of Figure 3-1. The first peak has an amplitude of b and the second peak has an amplitude of a. If a/b is equal to 0.25, then by the quarter wave damping criteria, the process is optimally stable. However, there is nothing special about the 0.25 criteria. Ziegler and Nichols, in their paper *Optimum Settings for Automatic Controllers* [11], make the following statement (bracketed segments are provided for clarification and are not part of the original text):

> "The statement that a sensitivity [gain] setting of one half the ultimate with attendant 25 per cent amplitude ratio gives optimum control must be modified in some cases. At times, a lower sensitivity is preferable, and results in a lower ratio. For example, the actual level maintained by a liquid-level controller might not be nearly as important as the effect of sudden valve movements on further portions of the process. … On the other hand, a pressure-control application giving oscillations with very short period could be set to give an 80 or 90 percent amplitude ratio [with higher attendant gains]. Due to the short period, a disturbance would die out in a reasonable time, even though there were quite a few oscillations.

Hence, the 0.25 criteria is an estimate of what is generally the best amplitude ratio.

3.2.2 Tuning and Loop Gain

An important fact about all of the response curves of Figure 3-1 is that they are the response of the entire control loop, i.e., the *process* part and the *controller* part. Figure 2-2 has been reproduced in Figure 3-2 and then converted to Figure 3-3 to show how the loop is divided into these parts.

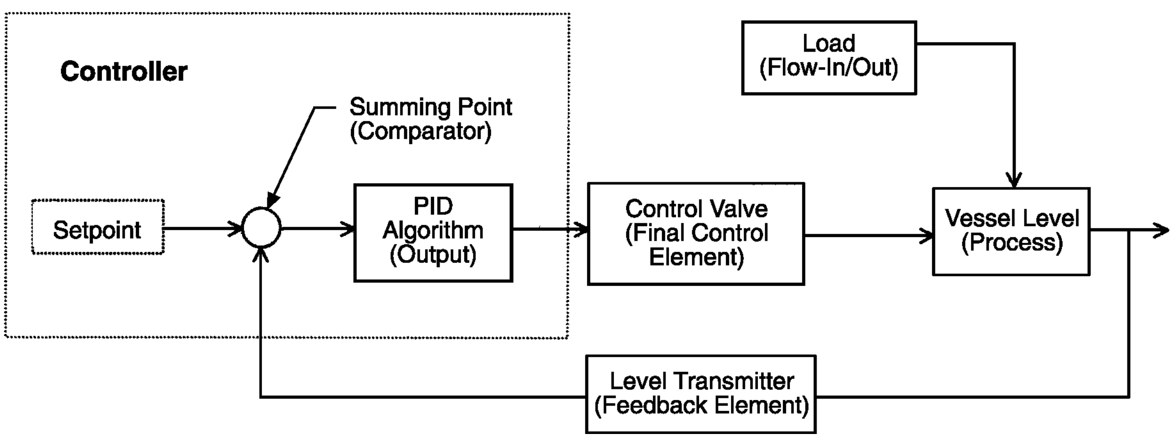

Figure 3-2
Level Control Loop Block Diagram

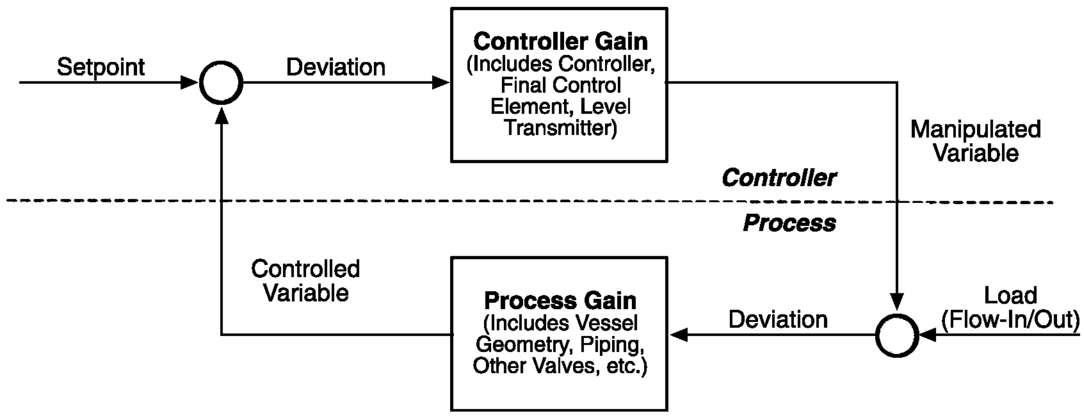

Figure 3-3
Parts of Control Loop Gain for Level Control

This combination of process gain and controller gain is referred to as *loop* gain. Thus, when the controller settings are being determined, they are based on the process gain that exists at the time of tuning. Just as changing controllers settings will change the response of the loop, so will changes to the process gain. Basically, process gain changes are the result of two events:

1. Changes in loop equipment parameters due to aging and/or failure, resulting in changed responses to controller input. An aging example would be control valve disc wear resulting in a change to control valve response (valve gain). A failure example would be a positioner failure due to dirt in the nozzle/flapper amplifier.

2. Process gain nonlinearities. This means that load changes that cause the process to be at a different operating point will result in a different process gain. The load change in the level control loop of Figure 2-1 is flow into the tank. To maintain level in the event of a change to the input flow, the valve flow, and therefore position, will have to change. This means that since the system flow characteristics are usually nonlinear (pressure drop is proportional to square of the flow), then the process will respond differently at the new load. A good example of this nonlinearity is the fact that component and piping pressure drops vary with the square of the flow. A discussion of the causes of control loop nonlinearity is found in Appendix C.

What this means to us is that **tuning is optimal only for the value of the PV that the tuning was performed at, or for the load that causes the PV to vary**. If the PV varies significantly <u>or if loads change</u>, the loop gain may vary significantly. Higher PVs or loads will result in higher process gains with the possibility of instability. Likewise, lower PVs will result in lower process gains and over-damping and longer settling times.

Key Technical Point

Tuning is optimal only for the value of the process variable that the tuning was performed at, or for the load that causes the process variable to vary.

3.2.3 Minimum Integrated Absolute Error

Before concluding this section, it should be noted that there are other stability criteria. The criteria that has gained the most popularity is referred to as the Minimum Integrated Absolute Error (MIAE), as shown in Figure 3-4. The description *minimum integrated absolute error area* means that the criteria used for tuning has the goal to minimize the shaded area. It removes many of the assumptions accorded the quarter wave damping criteria and results in better control. In a later section, this guide will provide coefficients used to determine controller setting for level control processes. Because of the better results, these coefficients will be based on the MIAE criteria.

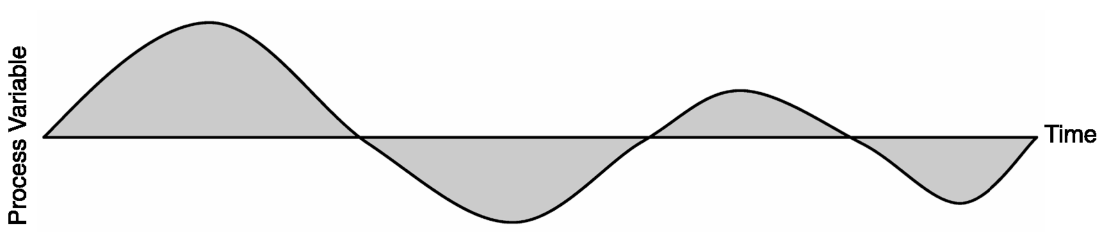

Figure 3-4
Minimum Integrated Absolute Error Area

3.3 Process Controllers

Process tuning involves adjustments to the controller. While the actions of the pneumatic controller (proportional and reset adjustments) have been described in Section 2, additional discussion will help facilitate the remaining discussion on tuning.

Controllers are classified by the signal generated based on the process error detected by the feedback loop. The three basic controller actions are proportional (P), integral (I), and derivative (D); there are various combinations, the most common being PI and PID. A brief description of controller action is necessary to understand its effect on the level control process.

Figure 3-5 shows the response of each of these controller classifications and a PI controller to a square pulse input. The square pulse represents two step changes, one increasing and one decreasing. These step changes are provided at the input of the controller (Figure 3-1), and the response is observed at the output of the controller. The square pulse is used since it shows the response to an increasing or decreasing signal as well as a signal that returns to its original value.

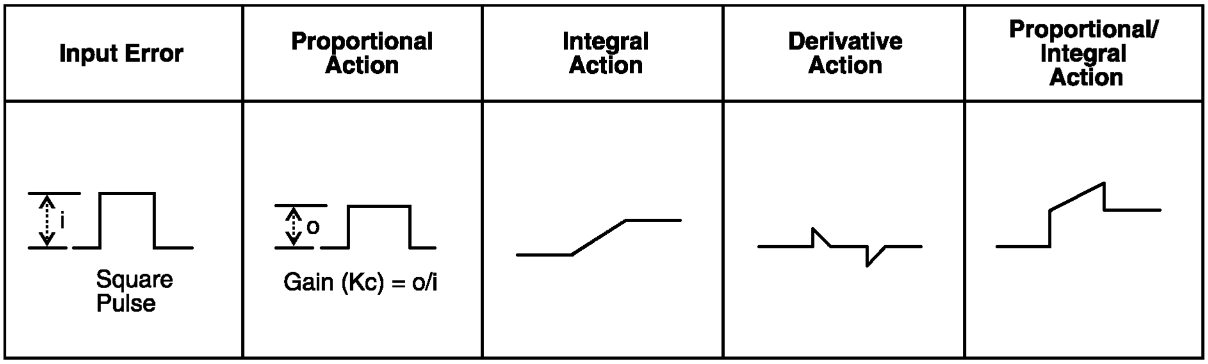

Figure 3-5
Controller Output Response to Square Pulse Showing Gain

3.3.1 Proportional Action

Proportional action is a control response in which there is a continuous linear relationship between the output and the input. This relationship is called *gain* (Kc), and is as shown in the left-most panel of Figure 3-2. In the controller, the gain is applied to the error between the setpoint and the feedback value, which is called the process or controlled variable. In some controllers, the gain is referred to as *proportional band* and is related to gain as follows: PB = 100/Kc. The term proportional band refers to the change in input required to produce a full-range in output due to proportional control action. The response of proportional action seen in Figure 3-4 is the reproduction of the square pulse, except that the height of the output is proportional to the height of the input.

3.3.2 Integral Action

Integral action (also known as *reset action*) causes the output of the controller to change at a given rate as long as there is an error. When the error does not exist or ceases to exist, the output does not change and remains at the value that existed when the error became zero. This is unique among the three control actions: both proportional action and derivative action values go to zero when the error goes to zero. The reason for integral action is to correct only one problem: offset.

Key Technical Point

The reason for integral action is to correct only one problem: offset.

Offset is a problem that occurs with proportional control and is related to the fact that the original setpoint is associated uniquely with the process load that existed when the process was placed in automatic. This means that the controller output is not zero when the input error is zero. This output may be thought of as a bias. A good is the shown by the level control model given in Section 2, where the level is established at the setpoint and the flow-in and flow-out are equal. The control valve is receiving a signal that positions it properly for the required flow. If the flow-in changes, then the level will change, and the position of the flow control valve will need to change to counter the effect of the flow-in change. To do this, however, the flow control valve requires a new signal to position it properly. This in turn requires an error to exist that will change the original signal to the valve, which means that the level can no longer be at the setpoint, but must be at some other level to create the error. This difference is called offset.

To correct offset, the integral action changes the bias. It does this by changing the output of the controller until the error is zero; and, as discussed above, holds the output at the new value that controls the new load at the original setpoint. The magnitude of the integral action is determined by the slope of the curve; greater slopes mean greater action. This slope is measured either as *repeats per minute*, in which larger values mean greater action, or as *minutes per repeat*, in which smaller values mean greater action. The term minutes per repeat is sometimes referred to as *integral time*, given in minutes or seconds, and is sometimes seen with the symbol tau (τ).

3.3.3 Derivative Action

Derivative action (sometimes called *differential action* or *rate control*) is not commonly used in power plant applications. It is never used alone, but is usually found in combination with proportional and integral control (PID). In derivative action, the output of the controller is proportional to the *rate of change* of the error signal and returns to zero when the error rate is zero as in steady state. Derivative control is adjusted using the *rate adjustment.* The units are time, with larger times resulting in greater action. Derivative control is most effective when the controller gain and integral action cannot achieve satisfactory process control without instability, which usually occurs when dead time is large. Derivative control will also improve slow loop response caused by lag.

3.4 Tuning Methods

3.4.1 Experience-Based

Many plants use an experience-based tuning method, which as its name implies, means determining loop settings using a set of rules based on experience. These methods tend to be favored by senior technicians and appear to achieve satisfactory results, but not necessarily optimal results. Experienced-based methods are described in Appendix B.

3.4.2 Model-Based

Model-based methods use a “test” that reveals certain process parameters that are converted into settings that, theoretically, should provide optimal results. Optimal results mean that the controller responses (proportional, integral, and derivative) are working together in a way to bring the controlled variable (process variable) back to its setpoint as quickly as necessary with the least variation from the setpoint. The quarter wave damping response is an example of optimal response.

Model-based methods have been developed from mathematical assumptions as well as empirical evaluations of process. The method of model-based tuning that has gained the widest acceptance is from the Ziegler-Nichols paper [11] discussed in Section 3.2.1. As pointed out in that discussion, since they are based on assumptions, the settings obtained through model-based assumptions are not necessarily the final ones. But for a process in which the optimal settings have never been determined before or in which changes have been made to equipment that affects the PV, the model-based approach is the most efficient in both time and optimal settings.

Model-based tuning is done either with the controller in manual or automatic. Tuning in manual means *open-loop tuning* while tuning in automatic means *closed-loop tuning*. Below is a brief overview of these methods. Additional information can be found in *Tuning Guidelines for Utility Fossil Plant Process Control* [1].

3.4.2.1 Open-Loop Tuning by Ziegler-Nichols

The Ziegler-Nichols open-loop method uses the process reaction curve (PRC). The PRC is simply the response of the process to a change in the controller output. To obtain this curve, the controller output is increased to approximate a step input to the process. As a result, the process variable (in this case, level), begins to change some time later (*dead time*), and continues to increase at some steady rate indicated by the slope of the curve.

Figure 3-6 shows a PRC with parameters that may be used to calculate the controller settings. Notice that this process variable continues to increase without limit. This is the response of a non-self-regulating process; the consequences of this response will be discussed later in this section.

The PRC method uses four pieces of data from these two curves. They are:

1. The percent change of the process variable (PV, level) over a specific period of time, T.
2. The percent change of the controller output (CO) that produced the PV change.
3. The amount of time before the PV began to respond to the change, called dead time, τ_d.

Three of these pieces are used to generate a process reaction rate factor Rr where

Rr = process response rate/controller output

Rr = (%ΔPV/ΔT)/%ΔCO

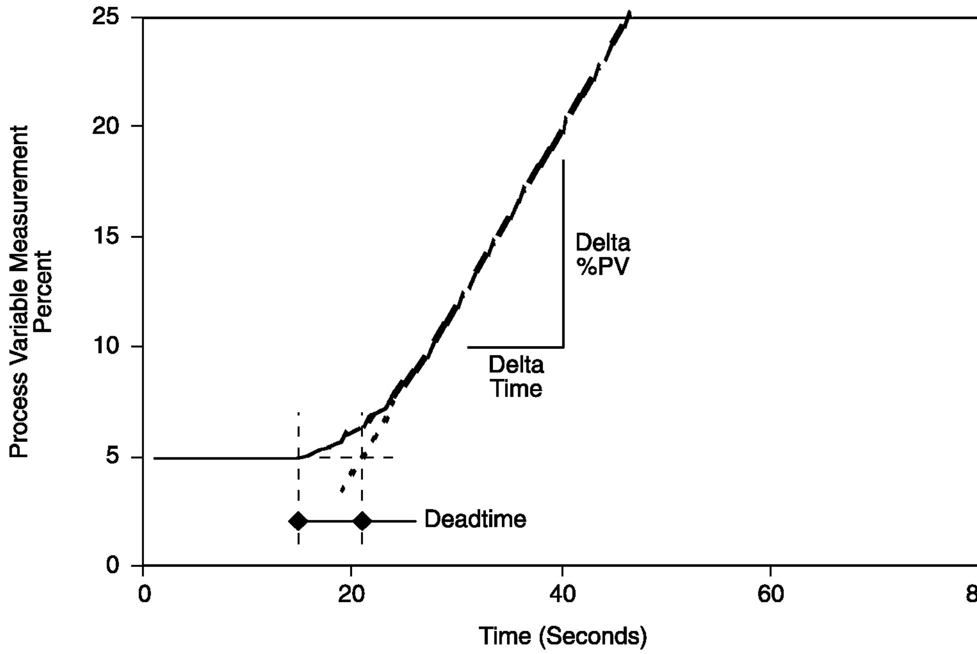

Figure 3-6
Process Reaction Curve Resulting From Step Input

Note the use of percentages in the formula. This results in Rr being in terms of reciprocal time since %ΔPV/% ΔCO is dimensionless. Process dead time, τ_d , seconds is determined as shown. Note the use of the intersection of the tangent line with the original process variable magnitude to determine a point that can be measured/read on the time axis. These values are now used to calculate the specific settings as shown in the following table.

Table 3-1
Controller Settings Based on Ziegler-Nichols Open-Loop Testing [11]

Controller Type	PB	Kc	I	D
P	100 Rr τ_d	1/Rr τ_d	-	-
PI	111.1 Rr τ_d	0.9/Rr τ_d	3.33 τ_d	
PID	83.3 Rr τ_d	1.2 Rr τ_d	2.0 τ_d	0.5 τ_d

Notes:
PB = Proportional Band Setting
Kc = Gain Setting
PB=100/Kc
I = Integral Time minutes/repeat
D = Derivative Setting, seconds

3.4.2.2 Closed-Loop Tuning by Ziegler-Nichols

While open-loop tuning is less likely to result in a transient, closed-loop tuning does offer the advantage of quicker results. In the case of most pneumatic controllers, it is the only way to tune since these controllers may not be placed in manual. This method is also known as the *ultimate cycles* or *ultimate sensitivity* method. It is based on determining a gain setting that produces sustained oscillations.

With the controller in automatic, the controller reset is placed at maximum time (minimum resets/time) and the derivative setting to minimum time. Gain is slowly increased (PB decreased) until sustained oscillations of the form shown in the middle panel of Figure 3-1 are obtained. This gain increase is done in small steps (≈10% of span) to maintain control and recover (reduce gain), if the oscillations continue to grow without limit (instability as shown in the right panel of Figure 3-1).

With sustained oscillations of constant amplitude, the time to complete one cycle (period) is recorded along with the gain setting (proportional band setting) that caused it. This period is referred to as the *ultimate period*, Pu, and the gain is referred to as *ultimate sensitivity*, Su (PBu), or *ultimate gain*. The controller settings are calculated as shown in Table 3-2, generally in the order shown. Note that once the Pu and Su are known, reducing the gain to one-half of Su (twice PBu) can be done immediately in order not to leave the process in sustained oscillations while other values are calculated.

Table 3-2
Controller Settings Based on Ziegler-Nichols Closed-Loop Testing [11]

Controller Type	PB	Kc	I	D
P	2 PBu	0.5 Su	-	-
PI	2.2 PBu	0.45 Su	0.83 Pu	-
PID	1.7 PBu	0.6 Su	0.5 Pu	0.125 Pu

Notes:
PBu = Sensitivity or gain in terms of proportional band setting required to obtain ultimate stability oscillations of center panel of Figure 3-1.
Su = Sensitivity or gain in terms of gain setting required to obtain ultimate stability.
Pu = Period associated with ultimate stability.

Once these setting are introduced, they can be tested by introducing a small setpoint change and observing the process variable response. It should look approximately like the left panel of Figure 3-1.

3.5 Control Process Types

Controlling level requires an understanding of the two basic types of control processes.

- Self-regulating processes
- Non-self-regulating processes

These control processes get their names from their response to a disturbance, e.g., a *bump test*. A bump test is conducted by placing the controller in manual and applying a step change in the controller output. It is important to distinguish between these processes because their differences determine the approach to tuning level control processes.

Key Technical Point

Processes are either self-regulating or non-self-regulating.

3.5.1 Self-Regulating Process

A self-regulating (SR) process responds to a bump test by moving to a different operating point and stabilizing there. An example of such a response curve is shown in Figure 3-7. A SR process by its nature limits itself internally depending on the controller output. Most processes are SR. The most common example of a SR process is liquid flow rate regulated by control valve position.

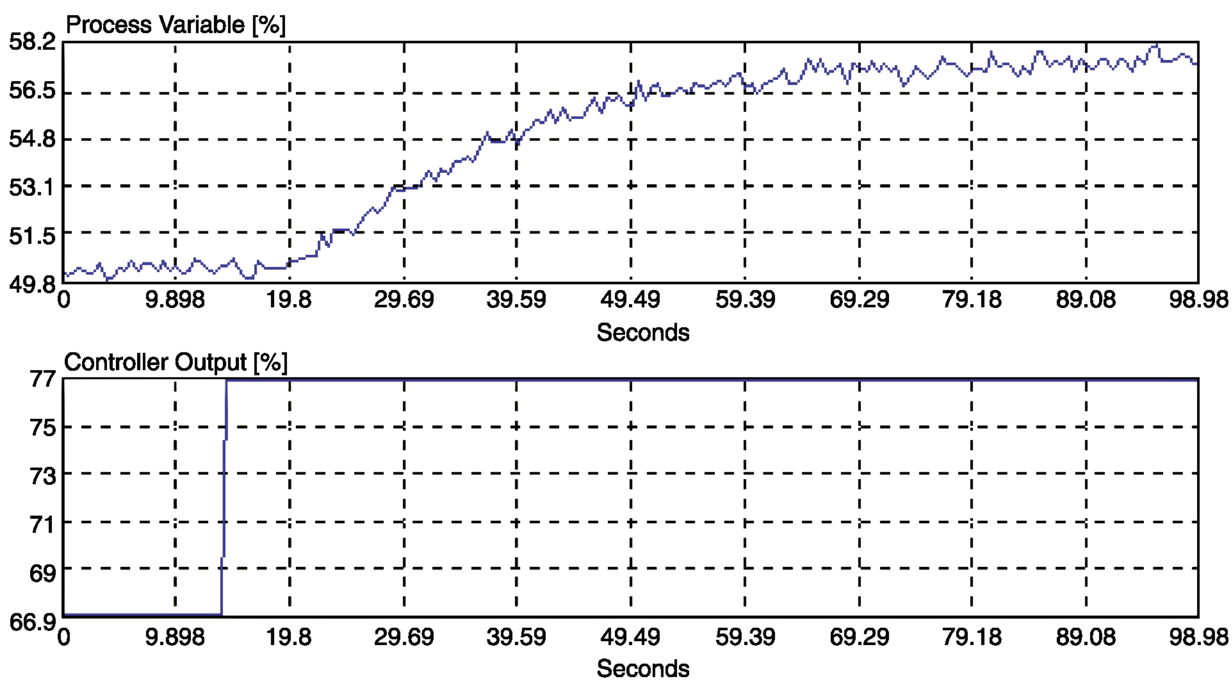

Figure 3-7
Self-Regulating Process

3.5.2 Non-Self-Regulating Process

A non-self-regulating (NSR) process responds to a bump test with a process variable that continues to increase or decrease at some rate. An NSR process will stop changing only if the controller output is returned to its original position. An example test curve is shown in Figure 3-8. These processes are sometimes called *integrating* processes because they integrate the "error" caused by the control valve change of position.

A level control process is usually NSR. As described above, the bump test will cause the level to change (the process variable) and it will continue to change as long as the controller does not bring the control valve back to the original position. There is one exception to this classification: the tank that drains strictly by gravity, e.g., without a pump. Because the flow for a particular valve position is controlled by the tank level head, which decreases as the level lowers, the flow can arrive at a new equilibrium exactly as shown in Figure 3-7. Therefore purely gravity drained tanks are SR. Any additional motivating force, e.g., a pump or tank pressure that causes flow significantly greater than gravity flow, makes a tank drain become NSR. That is why a feedwater heater drain level is, for all intents and purposes, an NSR process.

Key Technical Point

Feedwater heater drain level is a non-self-regulating process.

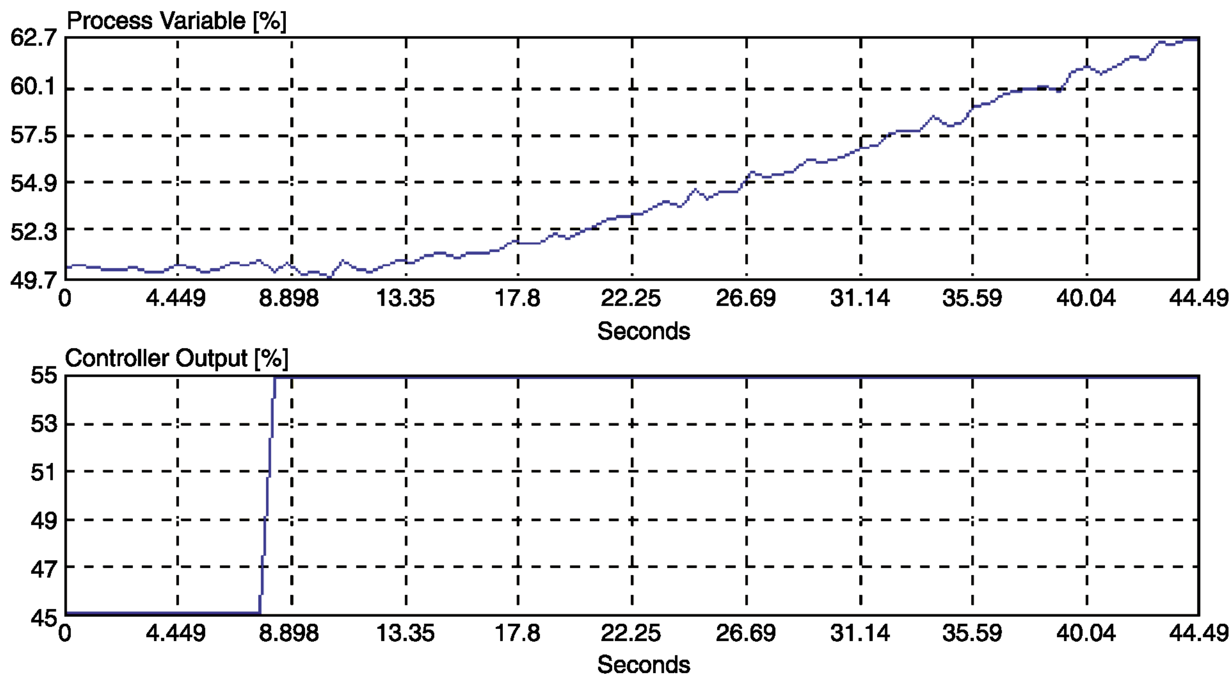

Figure 3-8
Non-Self-Regulating Process

3.6 Effect of Non-Self-Regulating Process on Tuning

3.6.1 Non-Self-Regulating Process Integral Action

If the curve for integral control shown in the center panel of Figure 3-5 is compared with the curve for the process variable in Figure 3-8, the similarity is obvious. Both outputs continue to change at some rate, $1/\tau$ for integral control and Rr for the NSR process, until the input (error or controller output) goes back to "zero," i.e., the original value. As discussed in Section 3.2.2, both the process and the controller have gain, and therefore both modify the signal they receive: the controller reacting to the error of the process and the process reacting to controller output. This means that in effect a process can be its own controller, which is exactly what it does in a SR process.

Now consider how the integral control drove the output to bring the process variable back to setpoint: It simply kept changing the output until it happened. Then the integral action stopped because there was no error. Compare this action with the NSR process. The process keeps changing until error is zero (the valve returns to the original position). In other words, the effect of the NSR process is the same as integral control. This means is that an NSR process has its own integral controller built in. As a result, controller integral action tuning is different from the SR process.

Key Technical Point

A non-self-regulating process has its own integral controller built in. As a result, controller integral action tuning is different from the self-regulating process.

3.6.2 Phase Shift

This difference in tuning is caused by phase shift. All controllers have phase shift. Phase shift can be explained as follows: During so-called steady state operations the input to a controller is, in reality, a slowly varying error shifting from one extreme to the other, which looks like a very slow, not-so-perfect sine wave with a very small amplitude. The controller output will of course be following this sine wave, but the sine wave will be opposite in polarity to the input. This can be seen in Figure 3-9.

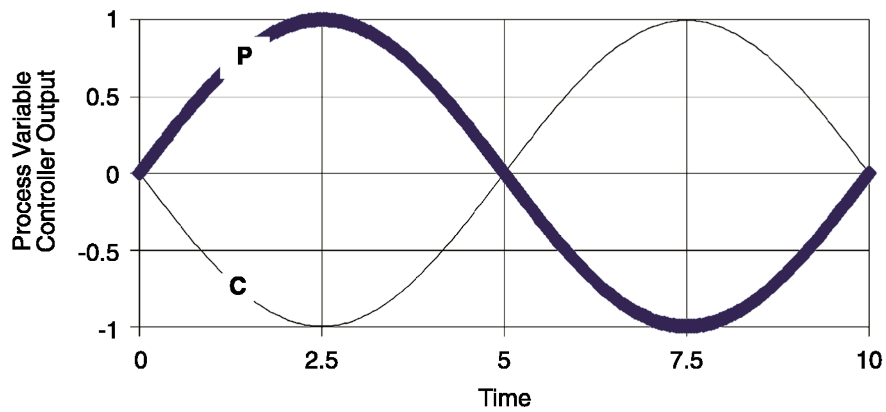

Figure 3-9
Relation of Output to Input of a Proportional Controller With Process Gain = 1

Another way to describe the output is that it is delayed by a half cycle. Since a full cycle of a sine wave goes is 360°, the delay or phase shift is 180°. Therefore, all controllers introduce a 180° phase shift and errors are nullified. This is the basis of negative feedback. Note, however, that if an additional 180° of phase shift is added and a total phase shift of 360° occurs, then the output would be *in-phase* with the input, causing the "error" to reinforce itself, and the process would become unstable through *positive feedback.* This is why dead time can be so devastating on a process—it can delay the process sufficiently to cause phase shift of sufficient magnitude for positive feedback to occur.

While dead time is one reason for a phase shift, it can also occur because of integral action of the controller and/or an NSR process. It can be shown mathematically that both integral action and the NSR process can each add 90°of phase shift to the process. (These mathematics are beyond the scope of this guide, but an explanation and derivation may be found on pages 14–15 and 24–25 of *Process Control Systems* [10].)

The rule for combining phase shifts is to add them. Therefore, if the integral action and NSR process each contribute 90° of phase shift, then when they are combined, there is a shift of 180°; as explained just above, the result is instability. That means that when tuning NSR processes, i.e., level processes, that use PI controllers, the use of integral action will not be very effective if applied in the normal way. The mathematics show, however, that if the integral time (I) is set at or above the ultimate period (Pu) obtained from the closed loop test, i.e., I ≥ Pu, then it does help. That is why the value used for the classical Ziegler-Nichols tuning (Table 3-2, I = 0.83Pu) will not result in optimal settings for the NSR process—instability will likely occur. However, this does not mean that offset control will not be effective, because the NSR process acts like an integral controller; that is, it pushes the PV to the setpoint inherently just as the controller integral action would. In fact, it is possible to control level quite successfully with just proportional control; for example, the bourdon tube controller described in Section 4.1.6 is a P type.

Key Technical Point

Using the classical Ziegler-Nichols tuning values will not be effective for the non-self-regulating process such as level control—instability will likely occur.

This problem does not impact PID controllers. The reason for this is that derivative action adds a *negative* phase shift, so that the controller/process phase shift is only 270°. Therefore, integral control will be effective. In fact, the use of integral and derivative action has been highly recommended for NSR processes [10].

3.6.3 A Tuning Method for the Level Control Process

As discussed in Section 3.6.2, integral settings for the SR and NSR process cannot be the same for optimal tuning. Therefore, while Ziegler-Nichols [11] did recognize the existence of the NSR process, referring to it as "not self-controlling," they did not address it in the formulation of the optimum settings for the controller. This can be inferred from the fact that the integral settings in Tables 3-1 and 3-2 do not distinguish between the SR and NSR process

However, for closed loop testing, constants similar to those in Table 3-2 have been developed, based on later investigations of the NSR process. They are not based on quarter amplitude damping, but on the minimum integrated absolute error (MIAE) tuning criteria mentioned in Section 3.2.3. Shinskey [10] has solved settings for PI and PID controllers based on the ultimate sensitivity and ultimate period obtained from Ziegler-Nichols closed-loop testing. These settings are shown in Table 3-3 below. Shinskey also distinguishes between PID controllers that are *interacting* and *noninteracting.* A discussion of the difference is found in *Process Control Systems* [10], page 114, and is shown schematically in the block diagrams of Figures 3-10 and 3-11. Guide users should obtain the classification for their controller from the controller manufacturer if PID control is used. It is of interest to note that Ziegler-Nichols settings were determined for the interacting controller shown in Figure 3-10.

Table 3-3
MIAE Criteria Controller Settings Based on Ziegler-Nichols Closed-Loop Testing for Non-Self-Regulating process [10]

Controller Type	Controller Sensitivity		I	D
	PB	Kc (See notes.)		
P	-	-	-	-
PI	1.65 PBu	0.61 Su	1.00 Pu	-
PID Interacting	1.80 PBu	0.56 Su	0.39 Pu	0.15 Pu
PID Non-interacting	1.30 PBu	0.77 Su	0.48 Pu	0.12 Pu

Notes:
Symbols above same as Table 3-2.
Symbols in [10] as follows: P = PB, Pu = PBu, and τ_n = Pu.
Kc is derived from [10] values for PB using the standard relationship Kc = 100/PB

Comparison of Tables 3-2 and 3-3 illustrate the previous discussions on use Ziegler-Nichols values for NSR processes:

- For the PI controller, Table 3-3 sets integral action 20% slower than Ziegler-Nichols (higher integral times mean slower action), and thus permits the use of a gain that is 35% greater.
- Integral action is set at the ultimate period of the process and not lower, as in the Ziegler-Nichols, where it would begin to cause problems with stability, because of the interaction with self-integrating action of NSR processes discussed in Section 3.6.2.
- For the PID controller, derivative action allows the integral action to become active and provide better control.

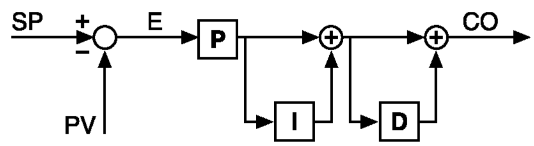

Figure 3-10
Interacting Controller (Classical, Series, or Real)

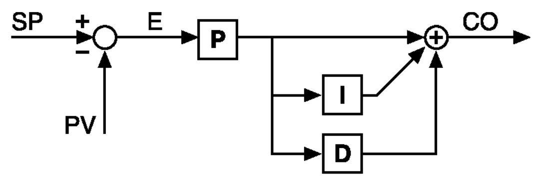

Figure 3-11
Non-Interacting Controller (Ideal, Standard, or ISA)

4
FEEDWATER SYSTEM NORMAL OPERATIONS

4.1 Introduction

This section begins the discussion on level control of feedwater heaters (FWHs), moisture separator/ reheater drain tanks (MSRDTs), and other drain tanks (DTs) associated with the condensate/feedwater system. This section may be skipped by the experienced individual who has training in balance-of- plant (BOP) design. This section will establish the relationship between these devices and show flows, temperatures and pressures for a reference 900 MW PWR balance–of-plant operation. A single reference plant has been chosen, since the variations in BOP design are too varied to cover all, and the principles and problems discussed do not vary with design.

4.2 Description of Reference Plant Power Cycle

The reference plant is shown in Figure 4-1. It is a relatively simple plant, as it has no drain tanks for the feedwater heaters and consists of only five stages of heating. Only one stage of heating takes place downstream of the feedwater pump. Drain coolers are found on all but one, i.e., FWH 4. FWH 4 is used to collect drains from FWH 5 and from the drain tanks for the moisture separator drain tank (MSDT) and reheater drain tank (RHDT), the latter through FWH5. The reference plant has two strings of FWH, although only one is shown. Power plants have either two or three strings. The same is true for the number of low-pressure (LP) turbines; the reference plant has two LP turbines. For every LP turbine, there is a moisture separator/reheater (MSR) and associated drain tanks. Nearly all plants have anywhere from five to seven FWHs, with one to three downstream of the feed pump.

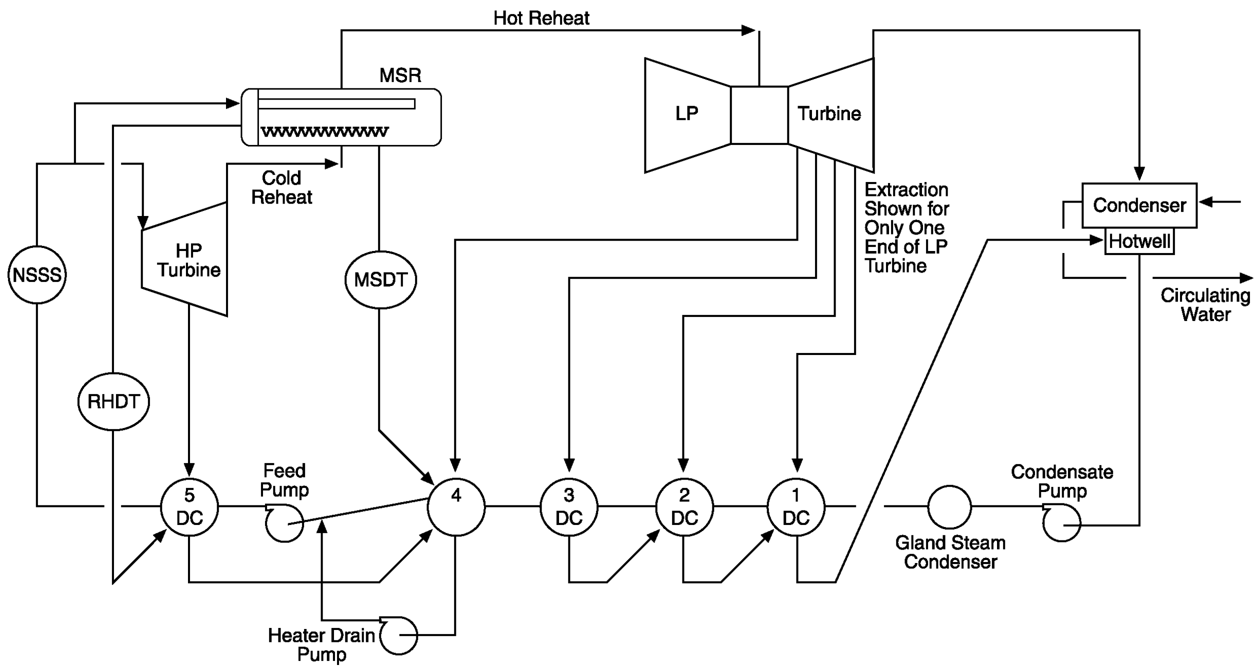

Figure 4-1
Reference Plant Power Cycle

4.3 Component Normal Operations

4.3.1 Steam Generation and Turbine Operations

The power cycle begins with the nuclear steam supply system (NSSS) of Figure 4-1. Steam is generated either in the reactor of the BWR or steam generator of the PWR and flows to the high-pressure (HP) turbine, where its thermal energy is converted to mechanical energy. The HP turbine is part of a tandem compound double-flow arrangement (only one flow is shown in the reference plant) and shares a common shaft with two LP turbines (only one is shown). Three LP turbines are also common in power plants. After exiting the turbines, steam flows through cross-under piping to the moisture separator/reheater, where moisture is separated or removed by mechanical scrubbers (chevrons, etc.) and then reheated by steam that had been tapped off the main steam lines at a point before it enters the throttle/governor valves of the HP turbine. In some plants, this reheating may consist of two stages, with the first stage receiving extraction steam (steam tapped off a stage of the HP turbine) and the second stage receiving from the main steam line as described above. This process of reheating improves the efficiency of the thermodynamic cycle.

The moisture separator is necessary before reheating due to the relatively large amounts of energy that would be required to change the moisture back to steam. Reheating then adds thermal energy to the steam before it enters the LP turbines, where the thermal energy is converted to mechanical energy, which, in tandem with the HP turbines, drives the electric generators (not shown).

In Figure 4-1, the LP turbine is drawn to show that steam enters the center of a double-expansion turbine where steam flows in two directions, expanding as it gives up energy and finally exiting each end. After exiting, the steam enters the top of the condenser and passes over tubes in which circulating water flows through the tubes to condense the steam. At the bottom of the condenser is the hotwell.

The hotwell is in reality a large drain tank where all the condensed turbine exhaust collects and which provides the emergency or alternate destination for drain flow from FWHs 2, 3, 4, and 5. It is the normal discharge point for FWH 1. The condenser is also where make-up feedwater is added, and it provides a reservoir for anticipated transients, e.g., after a turbine trip, to maintain reactor or steam generator level.

4.3.2 Condensate/Feedwater Operations

This operation consists of the flow of the condensate from the hotwell of the condenser to the inlet of the feedwater pump and back to the NSSS equipment. By convention, the flow through the tubes of a FWH is properly called *condensate* until it enters the feedwater pump, after which it is called *feedwater*. However, since the distinction is irrelevant for the discussions in this guide, the term *feedwater* will be used to describe all flow through the tubes. If there is a chance for confusion, the conventionally correct term will be used. The term *condensate* may appear in the context of extraction steam that has been condensed, but it will be clear to the reader that this is fluid on the shell side of the FWH.

4.3.3 Extraction Steam and Drains Operations (Bleed Steam)

Extraction steam (ES) is steam that is taken from the HP or LP turbines and used to preheat the feedwater prior to entry into the NSSS. In some plants, it may be called *bleed steam*. Like the reheating of the steam between the HP and LP turbines, preheating feedwater improves power cycle efficiency through a thermodynamic process called *regeneration*. The pressure and temperature of the ES depends on the point of extraction. In Figure 4-1, the highest pressure/highest temperature ES is taken from the HP turbine. In the LP turbine, steam pressure/temperature is reduced as the steam expands, as discussed in Section 4.3.1 above. Since the feedwater is being heated going from the condensate pump to the NSSS, it follows that the temperature in each FWH must be higher than the one before it. Therefore, the highest pressure/temperature heater, shown as FWH 1, receives its ES from the HP turbine.

As will be explained in later sections, FWH heating is done using the energy of condensing steam, which then, as a condensate, becomes part of the drains system. As can be seen in Figure 4-1, drains from the FWHs cascade from each higher-pressure heater to the next, using differential pressure (and sometimes elevation head) to drive the flow. This reliance on differences in pressure can be a problem, as discussed in Section 6.5.8. Drains from all FWHs upstream of the feedwater pump (except FWH 4) cascade back to FWH 1, which drains to the condenser hotwell.

4.3.4 Moisture Separator/Reheater and Drain Tank Operations

As mentioned in Section 4.3.1 above, the MSR both removes moisture and reheats the steam between the HP and LP turbines. The moisture removed is drained from the bottom of the MSR vessel to the moisture separator drain tank (MSDT). (In some MSRs, there may be an integral drain tank that discharges to a separate DT.)

The condensate formed from the main steam used in the reheater tubes is drained to a separate reheater drain tank (RHDT). If there is a second stage of reheating, the condensate formed goes to a separate DT.

4.4 Design Parameters

Table 4-1 shows the terminal temperature difference (TTD), drain cooler approach temperature (DCA), and differential pressures (DP) between adjacent heaters during various power levels. Table 4-1 shows the heater operating levels. The basis for showing pressures and temperatures that exist in the reference plant are shown in Table 4-3.

Table 4-1
Key Parameters for Reference Plant

FWH Drain Subcooling (1)

Components	Temperature Differences °F At Power Levels Indicated			
	100%	75%	50%	25%
ALL FWH TTD (2)	5	5	5	5
ALL FWH DCA (3)	15	15	15	15
FWH-5 DCZ SUBCL (4)	38	34	27	18
FWH-3 DCZ SUBCL (4)	49	46	41	34
FWH-2 DCZ SUBCL (4)	28	25	22	7
FWH-1 DCZ SUBCL (4)	44	31	13	0

Notes:
Subcooling is the number of degrees the fluid is below the saturation temperature.
TTD is the difference between shell saturation temperature and feedwater outlet temperature. Does not apply to FWH-4.
DCA is the difference between drain outlet temperature and feedwater inlet temperature. Does not apply to FWH-4.
Difference between shell saturation temperature and drain outlet temperature. Provides margin against flashing, as explained in later section.
°C = (°F – 32) * (5/9)

Table 4-1 (cont.)
Key Parameters for Reference Plant

Drain Motive Force

Components	Pressure Differences psi At Power Levels Indicated			
	100%	75%	50%	25%
FWH-5 to FWH-4	154	109	67	27
FWH-3 to FWH-2	33	24	15	7
FWH-2 to FWH-1	10	7	5	1
FWH-1 to CONDENSER	8	6	3	2

kPa = psi * 6.895

Total Inlet Flow to FWH (See Note)

Component	Total Inlet Flow Lb/Hr At Power Levels Indicated			
	100%	75%	50%	25%
FWH-5	1721047	1218356	754786	107021
FWH-4	4105484	2907777	1732764	484551
FWH-3	536457	358469	212124	96936
FWH-2	934582	619301	360045	136301
FWH-1	1466854	922882	486547	136301

Note: Flow is total for two trains. Divide by two for individual FWH flows.
kg = FWH * 0.454

Table 4-2
Heater Operating Levels

Component	Heater Operating Levels Percent Of Height		
	Low	Normal	High
FWH-5	14.0	16.2	18.3
FWH-4 (see note)	25.6	28.0	30.4
FWH-3	7.12	9.75	12.39
FWH-2	11.5	14.0	16.6
FWH-1	15.2	17.5	19.9

Note: FWH-4 has no drain cooling zone and is the reservoir for the heater drain pump.

Table 4-3
Reference Plant Source Data for Table 4-1

Component Pressure Psia Temperature °F	Percent of Full Power			
	100	75	50	25
RHDT Tank P	891	901	913	929(3)
FWH-5 Shell P	375	270	172	72
Shell T	438	408	369	305
Drn Out T	400	374	342	287
FW In T	385	359	327	272
FW Out T	433	403	364	300
MSDT Tank P (1)	221	161	105	45
FWH-4 Shell P	221	161	105	45
Shell T	390	364	332	275
Drn Out T (2)	379	353	322	270
FW In T	279	260	235	193
FW Out T	385	359	327	270
FWH-3 Shell P	52	38	24	11
Shell T	284	265	240	198
Drn Out T	235	219	199	164
FW In T	220	204	184	149
FW Out T	279	260	235	193
FWH-2 Shell P	19	14	9	4
Shell T	225	209	189	154
Drn Out T	197	184	167	147
FW In T	182	169	152	132
FW Out T	220	204	184	149
Component Pressure Psia Temperature °F	Percent of Full Power			
	100	75	50	25
FWH-1 Shell P	9	7	4	3
Shell T	187	174	157	137
Drn Out T	143	143	144	147
FW In T	128	128	129	132
FW Out T	182	169	152	132

Notes:
MSDT is above FWH-4 and drain flow to heater is by gravity.
FWH-4 does not have DCZ. Provides elevation head for heater drain pump NPSHr.
RHDT isolated from FWH-5 and flows directly to condenser.
°C = (°F – 32) * (5/9)

4.5 Feedwater Heater Startup/Shutdown

FWH startup and shutdown is very plant-specific and depends a great deal on original plant design as well as considerations for heat-up and cool-down, differential pressure, etc. Normally, during initial startup and final shutdown, extraction steam to the FWHs should be isolated when the pressure side of the isolation valve is greater than the heater shell pressure. Since heaters located in the condenser neck normally cannot have extraction steam isolated, they may be removed from service by diverting feedwater flow around the heater with a bypass system. During startup, FWHs should be placed in service starting with the lowest pressure heater. During shutdown, heaters should be removed from service in sequence, starting with the highest pressure heater.

5 OVERVIEW OF FEEDWATER HEATER AND MSR DRAIN TANK DESIGN

5.1 Purpose

This section presents a brief description of the design of the typical feedwater heater (FWH) and moisture separator/reheater (MSR) drain tanks (DTs) found in a nuclear power plant. It is important to understand the designs of these tanks because of the contribution of their geometry to the problem of maintaining level. Also, the design aspects of the FWH that establishes the required level must be known in order to understand the final setpoint that will allow the FWH to operate without internal damage and provide maximum heat transfer and efficiency but still respond to anticipated operational occurrences without affecting the plant adversely.

5.2 Feedwater Heater Function

The design of the FWH follows its function. The FWH is a heat exchanger that improves the efficiency of a power plant using a thermodynamic process called *regeneration*. The process involves the removal of steam, called extraction steam, from selected stages of the steam turbines (both high pressure and low pressure) and using the steam energy to preheat the feedwater before it enters the PWR steam generator or BWR reactor. In a nuclear power plant, FWHs also receive energy from the moisture separator drains (via the MS drain tanks), as well as receiving the condensed steam used to reheat the steam between the high-pressure and low-pressure steam turbines (via the RHDT). Finally, an FWH can receive energy from another FWH drain that is at a higher temperature. All of these energy inputs involve fluid flow—it is this fluid flow that makes up the drain flow.

5.3 Feedwater Heater Description

For the purpose of this guide, FWH designs used in a power plant may be simply classified by their longitudinal axis orientation and number of thermodynamic zones. Orientations are either horizontal (most common) or vertical. The thermodynamic zones are the *desuperheating zone*, *condensing zone*, and *drain cooling zone* (DCZ, sometimes called a preheating zone). The desuperheating zone design is found only in fossil plants. Nuclear plants use either a single zone (straight condensing) or two-zone (condensing and drain cooling zone) configuration. These classifications are summarized in Table 5-1 and illustrated in Figures 5-1, 5-2, 5-3, 5-4, and 5-5.

Table 5-1
Feedwater Heater Classifications (Nuclear Plants)

Orientation	Zone Description		Figure Number
Horizontal	Single-zone	Condensing zone only	5-1
	Two-zone	Full-pass partial-length DCZ	5-2
		Full-length partial-pass DCZ	5-3
Vertical	Two-zone	Vertical channel up Full-length partial-pass DCZ	5-4
		Vertical channel down Full-pass partial-length DCZ	5-5

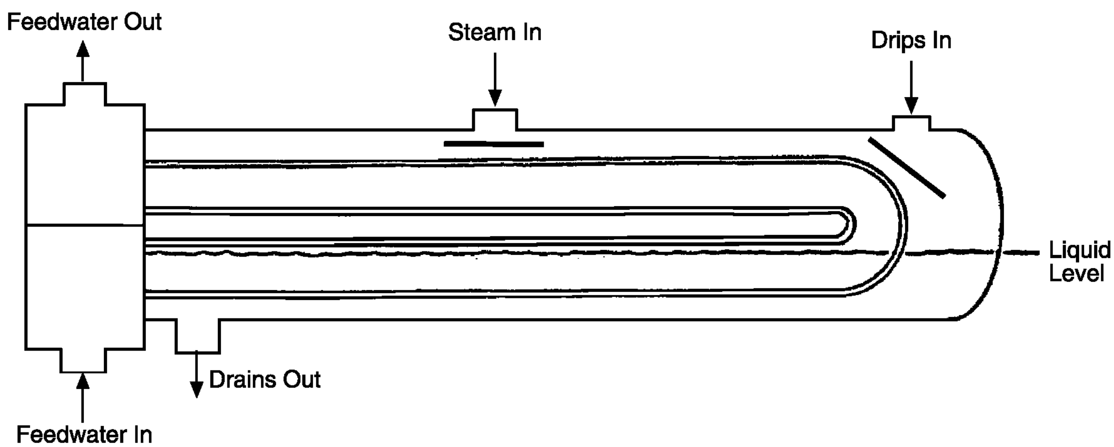

Figure 5-1
Single-Zone Horizontal Feedwater Heater (Straight Condensing)

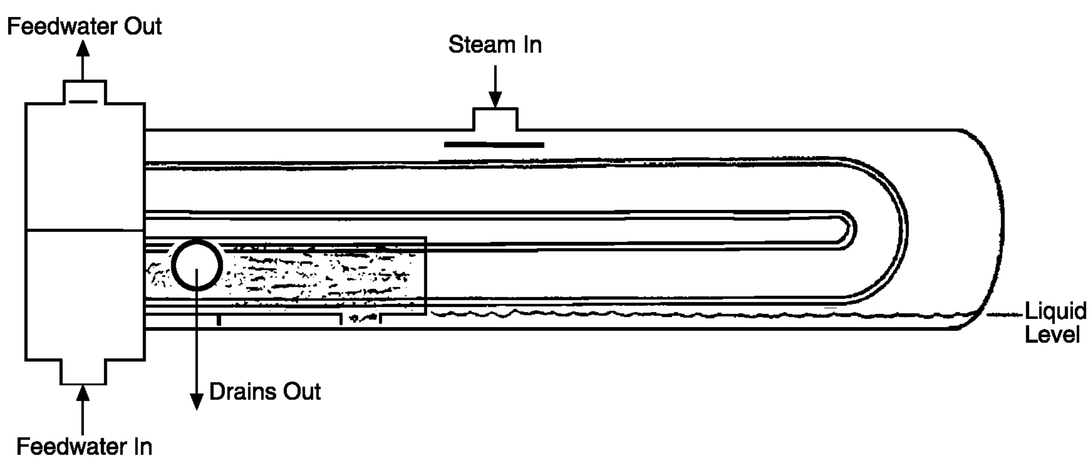

Figure 5-2
Two-Zone Horizontal Feedwater Heater With Full-Pass Partial-Length Drain Cooling Zone

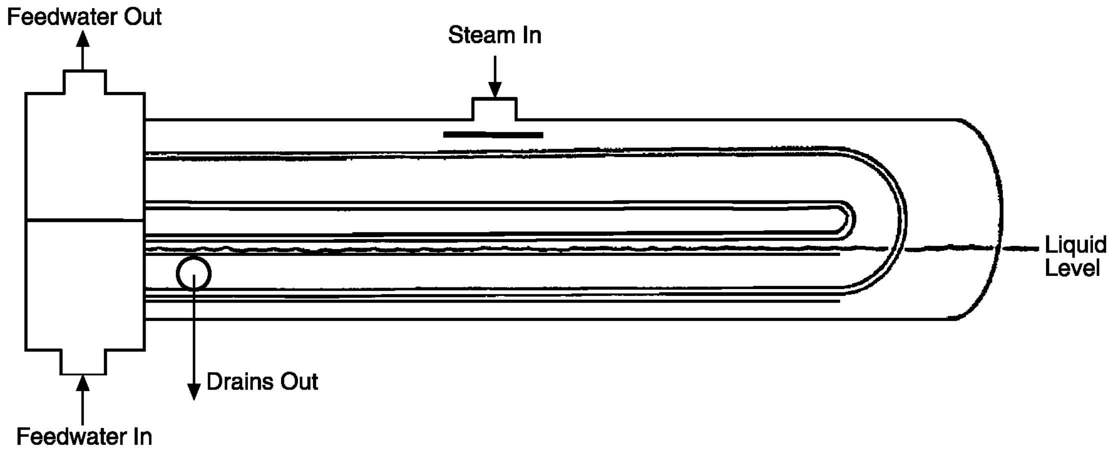

Figure 5-3
Two-Zone Horizontal Feedwater Heater With Full-Length Partial-Pass Drain Cooling Zone

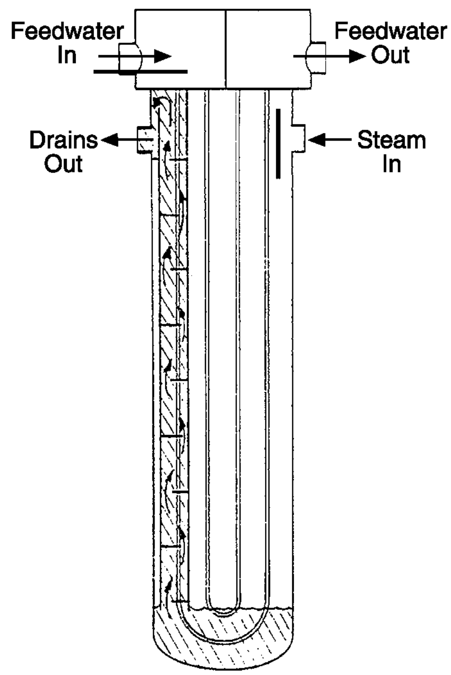

Figure 5-4
Two-Zone Vertical Channel Up Feedwater Heater With Full-Length Partial-Pass Drain Cooling Zone

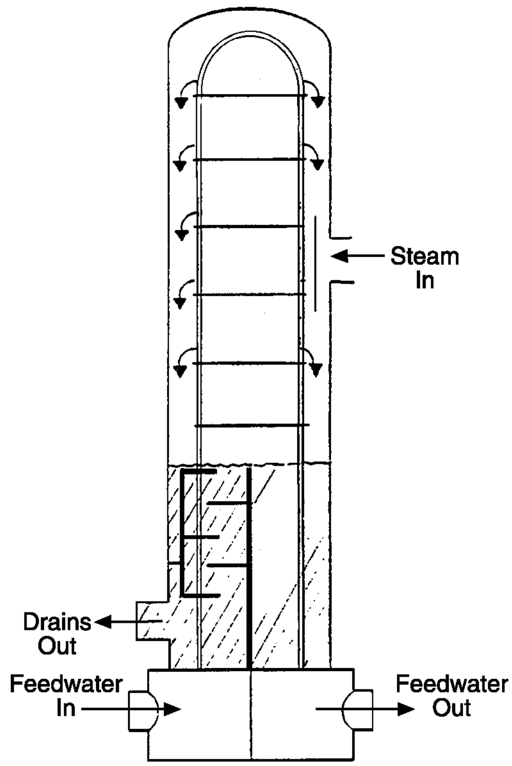

Figure 5-5
Two-Zone Vertical Channel Down Feedwater Heater With Full-Pass Partial-Length Drain Cooling Zone

5.4 Feedwater Heater Zone Discussion

5.4.1 Condensing Zone

The condensing zone is the largest zone in the FWH. As is shown in the above figures, all FWHs utilize a recirculation or a U-bend type of heat exchanger. Steam from extraction points on the high- and low-pressure turbines is routed to the top of the FWH shell. As the steam enters the shell, it impinges on a stainless steel erosion resistance plate, which protects the tubes from flow erosion. As the steam passes over the tubes, it condenses, giving up its heat energy to the relatively cooler feedwater that passes through the tubes. Any drains from higher pressure FWHs, moisture separators or reheaters flow into the condensing zone through the drains (drips) inlet nozzle shown in Figure 5-1. An impingement plate is also installed just inside this nozzle to protect the tubes from these flashing drains. The condensing zone is vented continuously to remove non-condensables, i.e., vapors other than steam.

5.4.2 Drains Cooling Zone

The drain cooling zone (DCZ), sometimes called the *drains subcooling zone* or *drains cooler*, is an enclosed portion within the shell extending from the channel end of the tube bundle. As shown in Figures 5-2, 5-3, 5-4, and 5-5 the DCZ can be full length (sometimes called long drains) or partial length (sometimes called short drains). The purpose of the DCZ is to maximize the heat transfer from the shell side condensate to the incoming feedwater before the condensate exits. The second and equally important reason is to provide sufficient subcooling (a temperature below the saturation temperature for the fluid temperature) to the exiting condensate to prevent flashing (becoming steam again) before the condensate reaches the FWH level control valve. This valve is mounted at or very near the lower pressure FWH drains inlet.

5.5 Moisture Separator/Reheater Drain Tanks (Bleed Steam Drain Tanks)

5.5.1 Reheater Drain Tank Design

Reheater drain tanks (RHDTs, sometimes called *bleed steam drain tanks*) are simply flow buffers or reservoirs that ensure positive drainage of the condensate formed by reheater tubes in the MSR. If a two-stage reheater is used, there are two RHDTs. RHDTs are typically cylindrical pressure vessels mounted horizontally or vertically, without any internal features of note. An example is shown in Figure 5-6. The RHDT is usually designed for main steam temperature and pressure, and typically will have one drips inlet and two drain outlets. The drips inlet receives condensate from the reheater tube bundle. One drain outlet is sent to the first-point (highest extraction steam pressure) FWH, or in some plants, to another collecting drains tank; the other drain is sent the condenser. Other smaller taps on the top and bottom provide for pressure, temperature and level measurements.

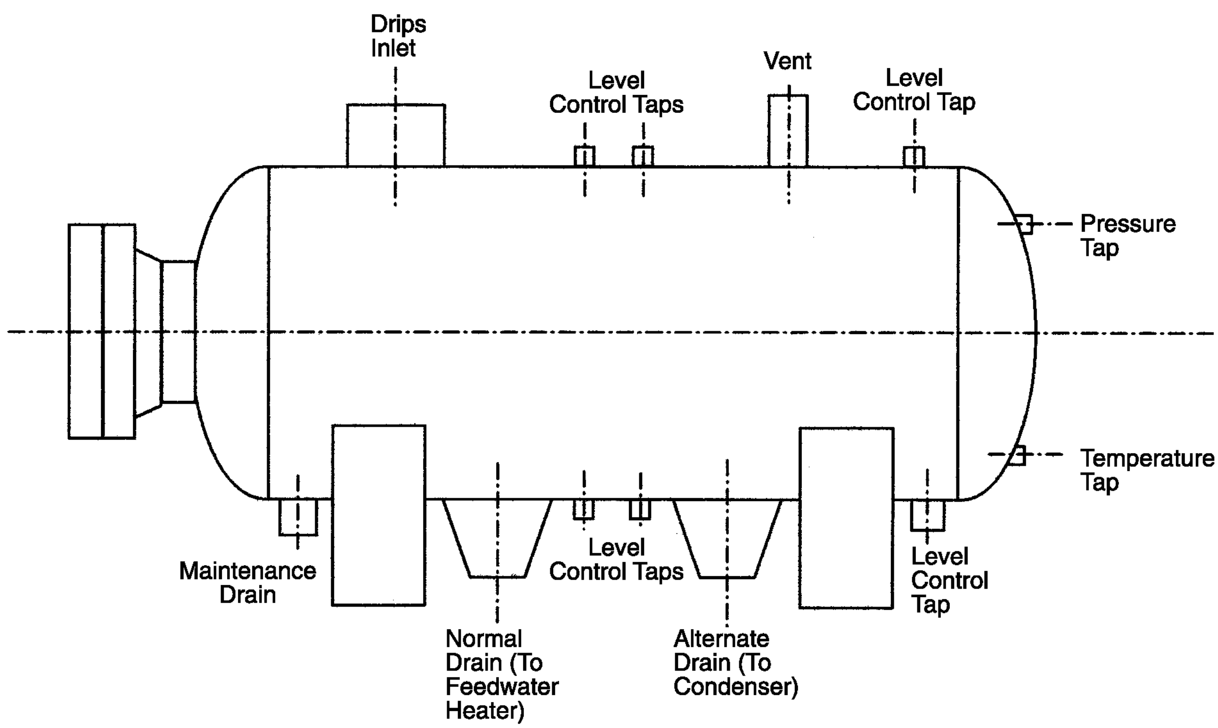

Figure 5-6
Reheater and Moisture Separator Drain Tank

5.5.2 Moisture Separator Drain Tanks

Like RHDTs, moisture separator drain tanks (MSDTs) are flow buffers that ensure positive drainage of the moisture separator section of the MSR. The MSDT may be an integral part of the MSR or a separate tank. If separate (as in the reference plant), they are similar geometrically to the RHDT (a cylindrical, horizontal or vertical tank, as shown in Figure 5-6), except that the MSDT can be designed for lower pressure and temperature (approximately those of high-pressure turbine outlet steam pressure and temperature), and therefore can be thinner than the RHDT. The inlet receives the condensate from the bottom of the MSR. The outlet(s) are sent to the highest pressure low-pressure FWH and to the condenser, respectively, each with its own control valve. Other smaller taps on the top and bottom provide for pressure, temperature, and level measurements.

6
BASIS FOR FEEDWATER HEATER AND MSR DRAIN TANK LEVEL

6.1 Introduction

In the preceding section, the basic designs of feedwater heaters (FWHs), moisture separator/reheaters (MSRs), and moisture separator/reheater drain tanks (MSRDTs), and their respective flow characteristics were discussed. The purpose of this section is to describe the operation of the shell side of FWHs, MSRs, and MSRDTs. This will include a discussion of the causes and results of improper level control.

6.2 Thermal and Fluid Dynamics of the Feedwater Heater and MSRDT

The discussion that follows considers the thermodynamic aspects of FWH and MSRDT operation. In some cases, the discussion is only applicable to FWHs. This applicability should be clear from the context of the discussion.

6.2.1 Sensible and Latent Heat

There are two distinct stages when boiling a fluid. As heat is added to the "cold" fluid, the temperature rises in proportion to the amount of heat added. At some temperature, corresponding to the pressure of the container, the temperature stops rising even though heat continues to be added. Vapor bubbles form, and eventually rapid boiling occurs. As long as the pressure remains constant and boiling occurs, the temperature of the fluid remains constant.

The energy required to bring water to the boiling temperature is called *sensible heat.* The energy required to boil or vaporize water is called *latent heat*. These terms apply to the reverse process as well. If steam is cooled to form a liquid, i.e., condensed, it gives off latent heat to the fluid used as coolant; when the temperature is lowered further, it gives off sensible heat.

The difference between sensible and latent heat is significant. Heat energy is measured in either British Thermal Units (BTU) or joules (J), where 1 BTU=1055 J. It takes about 152 BTUs (160.36 kJ) of energy to bring one pound (0.45 kg) of water (about 15.4 fluid ounces or 0.45 liters) from 60°F to 212°F (15.5°C to 100°C). But to boil this entire pound of water requires an additional 970 BTUs (1023.4 kJ), greater than six times more heat energy! Similarly, if this same steam is condensed, it will give up the 970 BTUs (1023.4 kJ) of heat energy. So, if water is the conveyor of energy, as it is in a power plant, using pure steam is a much more efficient use of the pound of mass coming out of the steam generator—this principle is used to maximize the efficiency of the regenerative process. The fluid that is extracted from the turbine is steam; when it passes through the FWH, it gives up its latent heat to the feedwater passing through the heater tubes, a process called *condensation*. In contrast, the feedwater passing through the FWH is not boiled, so the change in the energy content of the feedwater only involves sensible heat. As is discussed in Section 6.2.2, however, condensing the extraction steam comes with its own set of problems.

6.2.2 Saturated Conditions

Because the condensate at the bottom of the FWH has just been formed, it is at or very nearly at what is called *saturated conditions.* At saturated conditions (saturated pressure and temperature), water can exist as both a liquid state and a vapor state. In fact, at the interface between the liquid and vapor, the fluid is shifting from one state to the other continuously. All saturated fluids have a corresponding unique pressure for every temperature; this relationship is tabularized in a "steam table." A good example is the water in a coffee pot at 212°F (100°C), at an atmospheric pressure of 14.7 psia (101.3 kPa). The result of this situation is an environment that is unstable and is very sensitive to pressure variations and, to a lesser extent, to temperature changes. This can lead to flashing, cavitation, and other problems explained in Section 6.2.3.

Key Technical Point

Saturated conditions result in an environment that is unstable and is very sensitive to pressure variations and, to a lesser extent, to temperature changes. This can lead to flashing, cavitation, and other problems.

6.2.3 Flashing and Fluid Velocity

Flashing refers to *vaporization* of a liquid caused by a *reduction of pressure* to below the saturated pressure. It is, in effect, boiling; but boiling usually refers to vaporization caused by the *addition of heat* from an external source.

Flashing is an expansion process, since the volume occupied by steam is much greater than that of an equivalent weight of water. For example, when steam is formed at 212°F (100°C), it expands 1603 times. The amount of expansion diminishes as the temperature increases, and is about 63 times at 440°F (227°C).

Flashing is rapid, almost explosive, in nature. It is not the formation of one large bubble, but rather many small bubbles, which coalesce into larger bubbles. The extent and rate of formation of the bubbles depends on a complex combination of factors, as does the final pressure and remaining volume of liquid. Below are some of the factors that should be used to understand particular flashing events:

- Size of the pressure drop. More flashing will result from larger drops.
- Speed of the pressure drop. Faster drops will result in faster formation.
- Ratio of the vapor/liquid volumes. The larger the space for expansion, i.e., the existing vapor space, the less pressure perturbation there will be. Since there is more space for expansion,

the level of fluid in the vessel will drop more. On the other hand, where there is no vapor to begin with, flashing can cause rapid pressure changes and movements of the liquid away from the origin of the flashing.

- Amount of sensible heat removed. Flashing requires latent heat to occur and obtains this heat by using the energy content of the liquid. This involves the use of sensible heat contained in the fluid that is flashing, i.e., the temperature of the fluid drops. Therefore, flashing only continues until the temperature of the fluid reaches the saturation point for the new pressure.
- Area and flow resistance of the vent path. The amount of pressure that can be relieved through the vent path determines whether the pressure continues to drop causing additional flashing or reaches equilibrium. If the volume is isolated, e.g., by valves, flashing will cease to occur as describe above.
- The temperature when flashing occurs. The amount of energy required to vaporize a pound (0.453 kg) of water at 212°F (100°C) is 36.2 BTU/ft^3 (1.3484 MJ/m^3), while at 440°F (227°C) the energy requirements have gone up to 655.2 BTU/ft^3 (24.405 MJ/m^3). That means that the temperature drop at a higher initial temperature will be greater for the same volume of steam vaporized.
- Area of the liquid/vapor interface. Flashing will preferentially begin at the interface between the liquid and vapor. If there is no interface, i.e., all liquid, then it will occur at the point of lowest pressure, e.g., at the highest elevation or at the point of highest velocity.

The reduction of pressure discussed in the list above can occur in several ways:

- A vent path opens as a result of a transient. For example, extraction lines don't isolate or there is leakage through isolation valves.
- A flowing fluid encounters a restriction that causes a sufficient increase in velocity to reduce the local pressure (due to the conservation of energy, i.e., Bernoulli) below saturation. For example, this could occur at the entrance to the drain cooling zone.
- A flowing fluid enters a zone of lower pressure.
- A flowing fluid encounters an enlargement in the flow path, e.g., a tank or chamber that is at a lower pressure. For example, this could (and is designed to occur) just downstream of a level control valve at or near the entrance to the next lower heater.

6.2.4 Flashing Damage in the FWH

In a FWH, flashing can result in damage to the DCZ in one of two ways:

- The rapid expansion of the steam bubble occurs with such violence that it literally erodes a metal surface away. This erosion is characterized by a localized smoothing of the surface, having the appearance of small valleys.
- The formation of the steam bubbles causes the density of condensate to be considerably reduced, resulting in an increase in fluid velocity and possible tube vibration.

As an example of the latter, consider a flow of condensate at a saturated pressure of 60 psia (414.7 kPa) (292.7°F [144.8°C]). This would correspond roughly to the conditions existing in one of the middle stages of feedwater heating of a typical nuclear power plant. If there is a 5-psi (34.4-kPa) pressure drop (due to frictional loses), 0.62% of the condensate would flash into steam. While the amount of steam formed doesn't seem like a lot, because it is so much less dense (417 times the volume for the same weight), the overall density of the condensate goes from 58.8 lbs/cu ft to 15.4 lbs/cu ft (942 kg/m^3 to 247 kg/m^3), a 73% reduction.

Key Technical Point

The density of condensate is very sensitive to the effects of flashing. If only 0.62% of the condensate flashes at a pressure of 60 psia (414.7 kPa), the overall density of the condensate is reduced 73%.

This reduction of density has an immediate effect on fluid velocity. To maintain the same mass flow (lbs/hr), the velocity of the flow must increase (continuity equation), in this case, 58.8/15.4 lbs/hr (942/247 kg/m^3) or nearly four times. Because of this increase, it is likely that the tubes in the DCZ will vibrate excessively. Additional discussion on tube vibration is presented in Section 6.3.2.2.

Flashing can also occur outside the FWH in the drain cooler downstream piping (to the level control valve). This piping is designed to operate in the liquid condition (or state). Since the flow of any fluid involves pressure drops, the challenge is to keep the condensate in the liquid state not only while it passes into and through the DCZ, but also until it reaches the FWH level control valve. Since all valves involve a pressure drop, there will always be flashing downstream of the valve outlet. Therefore, the piping design downstream always provides a flash chamber specifically designed to operate continuously under flashing conditions. This chamber typically looks like a "T" connected to the outlet, with the neck pointing into a "drips" inlet of the FWH.

6.2.5 Cavitation Damage in the FWH

Cavitation is the reversing of flashing; therefore, cavitation damage is limited to those areas susceptible to flashing, as discussed in Section 6.2.4 above. If the same stream of fluid that has flashed (with many small bubbles), encounters an area of higher pressure, these bubbles of steam will collapse or implode. This collapse is termed cavitation. The velocity of the bubble collapse is much higher than the velocity associated with the bubble expansion of flashing—the resulting pressure waves have been reported as high as 150,000 psi (1034 MPa). If the fluid has transported the bubbles near a solid surface, these pressure waves can result in damage to the surface.

Key Technical Point

Cavitation is the reverse of flashing; therefore, cavitation damage is limited only to those areas susceptible to flashing.

6.2.6 Level Noise

Because the liquid and vapor phase of a saturated fluid is shifting from one phase to the other continuously at the surface interface, the level fluctuates rapidly. This fluctuation is small and uniformly distributed. This condition exists not only in the bottom of the heater but also in the level column where level is measured. Therefore, level sensors will detect small but detectable rapid level changes, referred to as *noise.* The effect on FWH level control is discussed in Section 6.5.8.

Key Technical Point

The surface of a saturated fluid will fluctuate rapidly, and this fluctuation results in level sensor noise. This condition exists throughout the feedwater heater and, in particular, the level column. Tuning that responds to this noise may result in premature failure of the final control element due to wear.

6.3 Basis for Feedwater Heater Operating Level

Sections 6.1 and 6.2 have discussed the dynamics and geometry of feedwater heaters. The following sections focus on the effects of these attributes.

6.3.1 Control Overview

All FWHs have a normal level control system and an alternate (or emergency) level control system, along with their associated control valve and drain paths. The normal feedwater control operates to maintain water level within a reasonable control band (range) under normal and abnormal steady state power operation. As Figure 6-1 shows, this band is centered near the lower tubes in the condensing (subcooling) zone and always above either the entrance to the drain cooler zone (DCZ) or the condensate outlet (where there is no drain cooler).

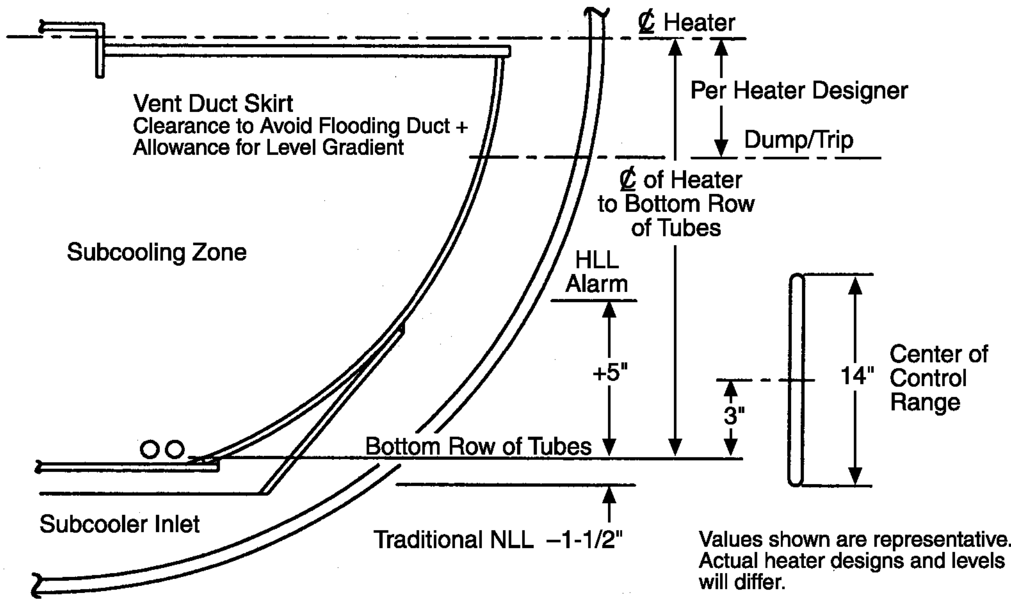

Figure 6-1
Horizontal Heater Levels [20]

The reason for centering the control band at this location is as follows:

1. As the condensate rises, it will begin to cover the lower tubes in the condensing zone and subtract from the tube surface available for condensing the extraction steam. Not covering too many condensing zone tubes is important because the condensing zone provides the greatest contribution to the increase in efficiency; deficiencies here can have the greatest cost to the plant heat rate.

2. If the condensate continues to rise, it will enter the extraction lines and ultimately the turbine, resulting in turbine water induction. The causes and results of turbine water induction are discussed in Section 6.3.2.5.

3. For FWHs without a DCZ, the normal control system maintains level in the FWH consistent with the net positive suction head required (NPSHr) of the heater drain pump (HDP) and prevents steam ingress to the suction piping of the HDP. Either of these conditions can lead to pump cavitation, or more likely, pump trip caused by the pump protection system, which uses anticipatory action such as net positive suction head available (NPSHa).

4. Finally, for FWHs with a DCZ, if the condensate level drops below the entrance to the DC, then uncondensed extraction steam will be admitted to the DC. The consequences of steam entrance to the DCZ is discussed in Section 6.3.2.

The alternate (high-level dump or emergency dump) drain control can be either an open/close valve operated by a level switch or a level control system in its own right, i.e., controlled just as the normal control. A third system may exist that acts as a backup to both the normal and alternate control and is on/off.

The alternate drain must always be routed to the condenser and provides the following functions:

1. During initial startup, it may provide a path for condensate that is formed during the FWH and extraction steam system warm-up.
2. During normal operations, it maintains the FWH level below the maximum allowed, consistent with prevention of turbine water induction, by providing an additional path for condensate in the event that the normal drain control system fails or is unable to control level due to a transient.

6.3.2 Results of Operating at Incorrect Feedwater Heater Level

6.3.2.1 Drains Cooler Approach Temperature Greater Than Design

This condition is a result of operating with an FWH level at or below the entrance to the DCZ, allowing steam to enter the zone. As discussed in Section 4.3.3 in this guide, the objective of the FWH is to heat feedwater prior to its entry into the steam generator/reactor. Therefore, the higher the outgoing feedwater temperature the better. While the primary heating comes from the latent heat of the extraction steam, a preheating effect helps this process in the DCZ by using the sensible heat of the out-flowing drains to raise the temperature of the feedwater where it enters the FWH. To do this, the FWH is designed to minimize the difference between the outgoing drain temperature and incoming feedwater temperature. This difference is called the *drain cooler approach temperature* (DCA). To determine if the DCA is greater than design, ASME Performance Test Code PTC 12.1 provides the most accurate result. However, for routine troubleshooting and quick checks of FWH performance, simply measuring the drains outlet temperature and feedwater inlet temperature and determining the difference will suffice. Assuming the plant is operating at 100% power, the DCA should be about 10–15°F (5–8°C). If operating at 75% load, then the DCA might be 7–15°F (3–8°C) depending on plant design. Review of the heat balance will normally show the proper value. (The reference plant heat balance was the source of Table 4-2.) However, if the test shows 20–30°F (11–17°C), there is strong reason to suspect that the DCZ is not functioning properly, and/or there is steam in-leakage (condensate level is below the entrance to the drain cooler), and/or flashing is occurring because of excessive inlet velocities.

6.3.2.2 Excessive Tube Vibration

All FWH tubes vibrate. The cross-tube flow of steam in the condensing zone and of condensate in the DCZ will cause vibration. Problems do not arise until vibration becomes sufficient to cause fatigue, collision between tubes and/or wear in support plates or baffle holes. This problem cannot be detected without an internal examination of the drain cooler. Excessive vibration in the drain cooler is the result of higher-than-design fluid velocities, which can be brought on by flashing and/or steam entry into the DCZ. Sometimes the use of the same FWH outlet for both normal and alternate drains may allow the flow carrying capacity of the single line to be exceeded during transients in which both the normal and alternate drains are open.

6.3.2.3 Cavitation-Type Erosion

Cavitation has been explained in Section 6.2.5 as the reversal of flashing—if cavitation is present, flashing is occurring upstream. The presence of cavitation has been described as a noise like marbles rattling in a bottle or frying bacon. Due to the loud background noises associated with flows through the FWH, the cavitation noise may not perceptible or difficult to locate. The first indication will be damage to the support structures within the DCZ. This damage will usually appear as metal deformation (taking on a sandpaper or metal file texture) or pitting. Since carbon steel is highly susceptible to this form of cavitation-type erosion, problems will first appear on parts using this material. This includes primarily spacers, rods, baffles, etc., since most nuclear power plants do not use carbon steel tubes. Although stainless steel tubes are normally resistant, they are not immune to cavitation-type erosion in extreme conditions. Another location that demands immediate attention when cavitation is indicated is upstream of the FWH drain control valve, since damage is rapid and such drain lines present a dangerous personnel hazard.

6.3.2.4 Increased Terminal Temperature Difference

Increased terminal temperature difference occurs when the operating level is too high. The objective of the FWH is to heat the feedwater prior to entry into the steam generator/reactor. Therefore, the higher the outgoing feedwater temperature the better. Since the primary energy for heating the feedwater comes from the incoming extraction steam, the closer the feedwater exit temperature is to the extraction steam inlet temperature the better. This difference is called terminal temperature difference (TTD), and a common TTD value used for design is 5°F [3°C]. To achieve this value, the FWH design requires that all but a few of the tubes be uncovered so as to maximize the use of the latent heat of the steam to heat the feedwater. Therefore, covering too many tubes will subtract from the *assumed tube heating surface* and result in a higher TTD. But as discussed in Section 6.3.1 above, the water level cannot go below the entrance to the DCZ without causing FWH damage in the DCZ. So as discussed in Section 7.3.2, the level may be allowed to cover the bottom rows of tubes, sacrificing some efficiency for reliability.

6.3.2.5 Feedwater Heater Isolation Due to High-High Level

FWH level control systems include a requirement for high-high level isolation of the heater to prevent turbine water induction. Water induced through the extraction piping to the turbine can seriously damage the turbine. The primary mechanisms of turbine water induction damage include:

- Thermal shock caused by the temperature difference between hot turbine components and cool vapor/liquid
- Overload to components caused by the impact of “slug,” “chunk,” or “particle” flows of water
- Rubbing wear caused by thermal distortion

Turbine water induction occurs when the level control system fails while the alternate drains do not open and the extraction steam non-return valves (if installed) do not close. The extraction steam lines fill, allowing water into the bottom of the turbine casing.

As a result of the damage mechanisms, the following types of damage will result from turbine water induction:

- Thrust bearing failure
- Damaged buckets/blades
- Thermal cracking of inner and outer casing and diaphragms
- Rub damage
- Permanent warping or distortion

Because any of these potential damage mechanisms can result in long forced outages, turbine water induction can, in a sense, actually be considered the most important consideration in FWH level control limits.

Key Technical Point

The most important consideration for FWH level control limits is turbine water induction. The potential damage to the turbine can result in long forced outages

Almost all water induction incidents occur during load transients, notably shutdown, startup, trips, and large load swings.

6.4 Basis for MSR Drain Tanks and Other Drain Tank Operating Levels

6.4.1 Reheater Drain Tank

In order to provide positive drainage of the reheat steam condensate, each reheater tube bundle must have a dedicated drain tank. In those reheaters with more than one stage of reheating, there must be no interconnection between the bundle drain systems and those draining feedwater heaters before the reheater drain tank. Normal level control and high-level alternate drains to the condenser are vital. The high-level setpoint should be located to prevent flooding of the tubes and subsequent backup that will result in thermally induced tube failures. Low-level isolation is also important. If the level is not held and the tank goes dry, excess flow through the drain system may damage the reheater tube internals due to high-velocity flow. For those plants with drain tank pumps, NPSHa must be maintained, which depends on elevation, pressure drops, etc.

6.4.2 Moisture Separator Drain Tank

The purpose of the moisture separator drain tank (MSDT) is to ensure that water does not flood the bottom of the MSR vessel and thus interfere with the proper flow of steam in the MSR and/or affect the moisture separation process. Sometimes this MSDT is an integral part of the MSR vessel and takes the form of a “hotwell” similar to that on a condenser. Unlike the RHDT, the MSDT drain system has very small pressure drops. Flow and to from the MSDT depends a great deal on elevation head. For this reason, MSDT lines may contain non-return valve (check valves), usually with power assist cylinders to ensure complete closure and prevent backflow from the FWH to the MSDT and then to MSR vessel, where it can cause damage due to thermal differences. The amount of water in the MSDT contributes to the amount of backflow.

6.4.3 Other Heater Drain Tanks

Some plants use a separate drain tank to collect various heater drains, rather than the bottom of the FWH. Some of these plant tanks may also have integral drain coolers. In many of these tanks, condensate is removed by drain tank pumps. Therefore, level requirements vary widely and may depend on pump NPSH requirements and/or other factors.

6.5 Challenges to FWH Level Control

6.5.1 Surface Flashing

The continuous flashing and condensation that takes place at the surface creates measurement noise. This noise may be a problem if proportional control gain is high, since the noise will be passed on to the control valve, causing excessive movement and higher failure rates. This is one of the reasons controllers are detuned, i.e., less than optimal gain.

6.5.2 Feedwater Shrink and Swell

Fluids that are at saturated conditions also exhibit a phenomena referred to as *shrink* and *swell*. Under steady-state conditions, both water and steam bubbles reside below the water surface, and the average mixture density is constant. Should pressure in the FWH decrease suddenly, the steam bubbles expand under the water surface, increasing the average mixture density. This causes an increase in the FWH level called *swell*.

Swell will nearly always accompany a load rejection because extraction steam pressures, which establish the FWH shell pressures, always go down with reduction in power. If the rejection is severe enough, it will have the potential for causing unnecessary alarms and/or dumping.

The converse of swell is *shrink.* If pressure were to build up suddenly, the steam bubbles in the steam/water mixture decrease in size and volume. This causes a decrease in level, although the mass of water and steam has not changed. Shrink, however, is not a common problem since a sudden increase in pressure is not likely.

6.5.3 Dynamic Effects of Internal Flows

Steam flow streams in the shell of the FWH are not constant and certainly not uniform. In particular, a highly localized velocity of steam across the top equalizing connection opening in the shell causes an aspirating action that reduces the pressure in the top equalizing leg. This can give a false high level that varies with load (extraction steam flow).

These same flows can also cause the condensate level in a horizontal, full-pass, partial-length FWH (Figure 5-2) not to be level during normal operation. The level can vary, depending on the position of the steam inlet (or inlets), the design of the internals, and the flow through the unit. The level can vary significantly from the tubesheet to the U-tube end of the heater, especially if drain cooler velocities are high. The problem, although not as significant in the partial-pass, full-length FWH design (Figure 5-3), does exist, and must be considered when setting the level. The answer to this problem is to perform a mini-performance test on the heater.

In the vertical channel-down heater (Figure 5-5), cascading condensate flow will enter the top equalizing leg. This flow can be too high for an equal amount to leave by the lower equalizing line and will result in a false high level.

While the above effects always exist, they can be compensated for by conducting a level test in which an optimum *indicated level* is determined that establishes the proper TTD and DCA. (This test will be discussed in the next section.) Since this test will rely on an indicated level that is influenced by the amount of flow and flow velocities, it is important that the test be done at normal power level, i.e., 100%.

6.5.4 Instrument Connection Problems

A top equalizing leg that is too long may allow excessive condensation to occur. This condensate flow can be too high for an equal amount to leave by the lower equalizing line and can result in a false high level. The longer the leg the greater the problem. Insulation will help minimize the problem.

Loop seals that trap condensate in the top equalizing line or high points that trap non-condensables in the bottom leg will result in false indication.

Finally, sediment partially blocking the bottom equalizing connection opening or the leg itself will have the effect of reducing flow out of the lower equalizing leg. This will result in a false high level.

6.5.5 Capacitance

Capacitance is the volume of water per inch of level change that is required to maintain level in the feedwater heater within an acceptable band for the response characteristics of the control system. Low capacitance is a problem because the level changes rapidly due to variations in heater inflows and outflows, and some control systems cannot respond quickly enough. Since the volume is directly related to the surface area, it follows that vertical heaters are sensitive to this problem while it is never a problem for horizontal heaters.

When vertical heaters have a capacitance problem, the simplest solution is to modify the heater with a "belly band." A belly band is a section of heater that has a larger diameter and hence a larger surface area for the level range of interest. An alternative to the belly band is a separate pressure vessel connected by piping to the FWH. This vessel would be in "parallel," with a length appropriate for the level range of interest. Figure 6-2 shows the design concept of a belly band.

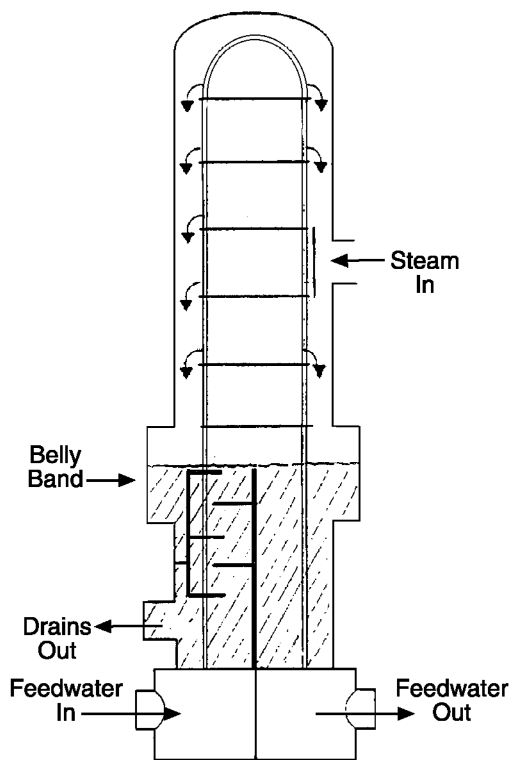

Figure 6-2
Belly Band

6.5.6 Control System Response Lag

Lag is the time it takes for a device to achieve some output value after it begins to respond. For the level control system, lag is the result of several factors:

- Level column level that lags behind the actual level because of:
  - The flow resistance of the sensing lines connected to the FWH or MSRDT
  - The continuous flow back to the FWH or MSRDT (in the lower line) due to steam condensing in the upper portion of the level column
- In pneumatic level controllers, the inherent input signal processing time needed to provide the appropriate signal to the final control element (the control valve)
- The travel time for the final control element to position to the controller demand

6.5.7 Nonlinearity of Process Response Due to Horizontal Feedwater Heater Geometry

The level response of a horizontal FWH or MSRDT will be nonlinear due to the geometry causing the surface area of the condensate to be different at different levels. Figure 6-3 shows this relationship as percent tank volume versus percent height. For comparison, a straight line showing a linear relationship is also shown. By examination, it is apparent that while the nonlinearity does exist, the problem is not serious when considering control system response for level control, particularly in the range from 10% to 30% level. In fact, if a linear regression line were to be plotted using the tank values for that range, the correlation coefficient would be 0.9968. Since perfect correlation or linearity corresponds to a coefficient of 1.00, this means the tank curve is linear for all practical purposes in that range. Further, since the reason linearity is important is primarily for control purposes, the range of levels considered can be much smaller. As noted in Table 4-1, the reference plant has one heater that operates between 7.1% and 12.4%, in what appears to be, as shown in Figure 6-3, a very nonlinear part of the curve. Using a range of 7–13% and plotting a linear regression line would, however, result in a correlation coefficient of 0.9986, better than the 10–30% range.

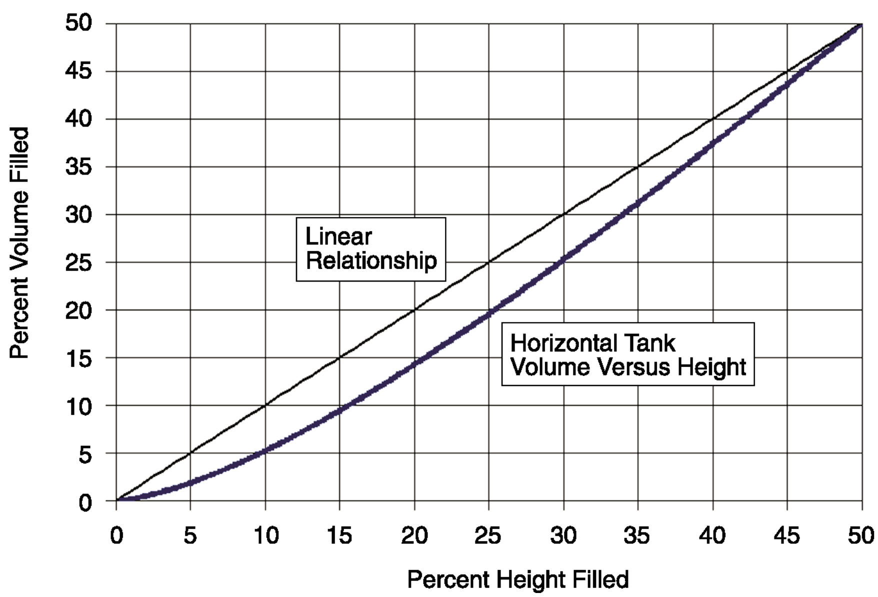

Figure 6-3
Horizontal Tank Volume Change With Height

Key Technical Point

For the narrow ranges of level changes involved in horizontal feedwater heater level control, tank geometry has little effect on level control linearity.

6.5.8 Level Noise

As discussed in Section 6.2.6, because the liquid and vapor phase of a saturated fluid is shifting from one phase to the other continuously at the surface interface, the level fluctuates rapidly, creating small but detectable rapid level changes referred to as *noise.* This noise will be reflected throughout the control process depending on the gain of the sensor/transmitter as well as controller gain. If the control system is tuned to respond to this noise, the additional movements of the control equipment—that is, the final control element—can cause premature wear failure. This problem can be dealt with using a low-pass filter for electronic/digital control or detuning (turning gain down to less than optimal).

Key Technical Point

The surface of a saturated fluid will fluctuate rapidly, and this fluctuation results in level sensor noise. This condition exists throughout the feedwater heater and, in particular, the level column. Tuning that responds to this noise may result in premature failure of the final control element due to wear.

6.6 Challenges to MSR Drain Tank and Other Drain Tank Level Control

The effects discussed for FWHs are equally applicable to drain tanks that receive saturated liquid flow. What is usually not as important is the need to keep level controlled in a narrow band, as there are no TTD or DCA requirements, so level noise isn't usually a concern.

However, uncontrolled flashing due to a drop of pressure during a transient can eliminate available NPSH quickly. Even if the "source" of low pressure, i.e., the vent, can be isolated and the formation of the vapor from the flashing mitigated, fluid loss will still result in a pump trip, since there is no makeup in the tank.

6.7 Other Considerations

Other causes may be operating that appear like a level control problem because the DCA is high. High DCA, not caused by low level, is almost always caused by:

- Flashing because of a higher than design pressure drop at the entrance to the DCZ
- Flashing because of an higher than design pressure drop within the DCZ
- Steam leaks in the drain cooler shroud above the water level, especially in shroud welds
- Steam leaks into the drain cooler through the end plate tube hole/tube crevice (annulus)

The first two problems usually occur because the flow though the DCZ is too great. This is usually a problem with FWH design. The third problem can occur due to design, manufacturing, or material failures, while the last is usually a design problem due to inadequate tube hole design. The existence of all four can only be confirmed by FWH internal examination. Below in Section 6.7.1 is a discussion of steam leaks.

6.7.1 Leaks in the Drain Cooler Shroud (Defects)

Leaks in the drain cooler shroud are almost invariably the result of material deficiencies going back to manufacture or design. These leaks only occur in horizontal full-pass, partial-length (Figure 5-2) and vertical channel-up FWHs (Figure 5-4) in which the shroud is nearly surrounded by steam. The steam leaks through weld cracks, etc. and enters the DCZ, where it causes flashing and cavitation as described in Section 6.2.3.

6.7.2 Leaks in the End Plate Tube Annulus

This problem only occurs in horizontal full-pass, partial-length FWHs (Figure 5-2) in which the tubes pass through the DCZ shroud end plate. The tube/tube-hole annulus is supposed to be designed to make the pressure drop high enough to make the leakage very small but acceptable. If an annulus becomes too large, then the effect is the same as described in Section 6.7.1.

7
MANAGING LEVEL FOR FEEDWATER HEATER AND MSRDT RELIABILITY AND EFFICIENCY

7.1 Introduction

For the base-load nuclear power plant, the need for long “runs” is a way of life. Capacity factors to support company goals are ever being nudged upward and ways to more effectively operate plant equipment are continually being emphasized. In the preceding section, level control in general and level control of FWHs and MSRDTs in particular were described. In this section, these level control discussions are used as the basis for strategies that will improve FWH and MSRDT reliability and efficiency. Generally, the order of the following sections is not intended to indicate priority.

7.2 Calibration

Calibration is done during an outage and ensures that the input and output ranges are as specified so that the loop can be considered calibrated. Proper calibration also has as its goal to ensure that the overall linearity of the control system is maintained. Calibration measures the dynamic response of individual accessories (e.g., E/P, positioner, booster) to a control input. The intent is to ensure that each accessory is functioning correctly within design tolerances (e.g., start and stop points, travel, timing).

Calibration thus focuses on the design specifications of the accessories. It provides assurance that the process is being controlled properly, at least as far as the inputs to the actuator and valve are concerned.

Calibrations are useful in providing information on accessory conditions; persistent, significant calibration drifts can identify the need for accessory replacement. Calibration may be the sole source of information available for this purpose, as it is not cost-effective to internally examine the condition of equipment. For example, valve or operator internal degradation can occasionally be inferred from calibration data, although not with any precision as to the location or quantification of the degradation mechanism. Persistent calibration drift may suggest the potential for internal damage to the valve and would likely be factored into a decision to investigate further.

Calibration should include all level loop equipment, including:

- Set limit switches
- Pressure regulator setpoint
- I-P / E-P transducers
- Positioners
- Booster tuning
- Pressure switches
- Controllers
- Pressure transmitters

7.3 Liquid Level Testing

7.3.1 Need For Testing Feedwater Heater Level

Proper level is about tradeoffs between thermal performance and equipment reliability. With respect to thermal performance, if the level is too high, i.e., above design, the terminal temperature difference (TTD) will be high. Similarly if the level is too low, the drain cooler approach temperature (DCA) will be too high. While being closer to TTD is thermally better than being closer to DCA, the overriding consideration should be FWH reliability, i.e., long-term operation.

With respect to FWH reliability, the most important consideration is the adverse effect of steam entering or forming in the drain cooling zone (DCZ), causing material damage as described in Section 6.2.5. This immediately establishes a lower limit below which operation is forbidden under all operating conditions.

Proper level is where the TTD and DCA are at their design values and a sufficient level margin exists to prevent steam from entering the DCZ or water entering the turbine. These goals and limits provide the criteria for establishing proper level.

Key O&M Cost Point

Proper level is where the TTD and DCA are at their design values and sufficient level margin exists to prevent steam from entering the DCZ or water entering the turbine.

Do not rely on the manufacturer's markings. They are design values and do not take into account all of the effects of internal flow and condensing described in Section 6.5.3. In addition, these effects are power dependent. To ensure that the effects are minimized at normal power, the proper level must be established at normal power, i.e., 100%.

Key Technical Point

Manufacturer's markings are design values and do not take into account all of the effects of internal flow and condensing that occur during feedwater heater operation.

This level test must be done at least once, preferably as soon as the FWH is put into operation for the first time. If a level test has never been done and no damage has occurred, then it should still be done to ensure that the plant heat rate is not being affected. Table 7-1 shows the effect of operating outside design values.

Table 7-1
Feedwater Heater Impact on Thermal Performance [21]

Change	Effect
1°F increase in top heater TTD	0.016% increase in heat rate
1°F increase in other stage heater TTD	0.013% increase in heat rate
1°F increase in DCA	0.005% increase in heat rate

Note: Heat rate is a measure of plant efficiency and is usually expressed in BTU/kWHr with lower values designating better efficiency.
$\Delta°C = (\Delta°F) * (5/9)$

If the tubes that pass through the DCZ are plugged subsequent to this test, then the test must be performed as soon as the heater is put back into operation. This is because, while the pressure drop across the plugged tube remains the same, the cooling capability has been removed and a flashing potential exists. Similarly, this test must be done any time work is done in the FWH that can change conditions in internal flow, including power uprates, T_{hot} changes, etc., where extraction steam flow and other flows may change, thus changing the condensate level distribution within the FWH and changing level indications due to flow effects at the taps.

7.3.2 Level Test Methodology

The method described below determines the optimal level that minimizes both TTD and DCA temperatures. Since the design of an FWH accommodates covering some of the tubes while meeting TTD, if design TTD and/or DCA temperatures unexpectedly are not met during the test, then troubleshooting is indicated.

If it is not possible to correct the problem immediately, then the DCA should be made as close to the required value as possible. This usually means that the TTD will be high, but it also means the DCZ entrance or snorkel will be covered. There will be a loss in efficiency, but the long-term reliability of the FWH will be preserved.

The top heater (the highest pressure heater) should be tested first and all lower pressure heaters tested in order to avoid interactions due to cascading drains. In addition, if the DCA and/or TTD temperature are not met, the top heater must be given priority for troubleshooting, since it contributes most to the heat rate of the plant.

Key Technical Point

When testing feedwater heaters for optimal level, the top heater (highest pressure heater) should be tested first, followed, in order, by all lower pressure heaters, to avoid interactions due to cascading drains.

The following is a general description of the method. The following data are required:

- Level
- Shell pressure
- Extraction steam temperature (saturated temperature for shell pressure as determined from a steam table)
- Drain outlet temperature
- Inlet feedwater temperature
- Outlet feedwater temperature

1. The test begins by the slowly increasing the level of each tested FWH to the high alarm point. Two possible methods for raising the water into the feedwater heater are 1) to take manual control of the normal level control valve and throttle as necessary or 2) to raise the setpoint on the normal level controller. Although 2) is the preferred method, the setpoint dial must be calibrated within the full range of the level column.

2. After level and temperatures have stabilized, data is recorded, and the TTD and DCA are calculated as follows:

    - TTD = (Extraction steam temperature) – (Outlet feedwater temperature)
    - DCA = (Drain outlet temperature) – (Inlet feedwater temperature)

3. The test data are plotted on a graph similar to Figure 7-1.

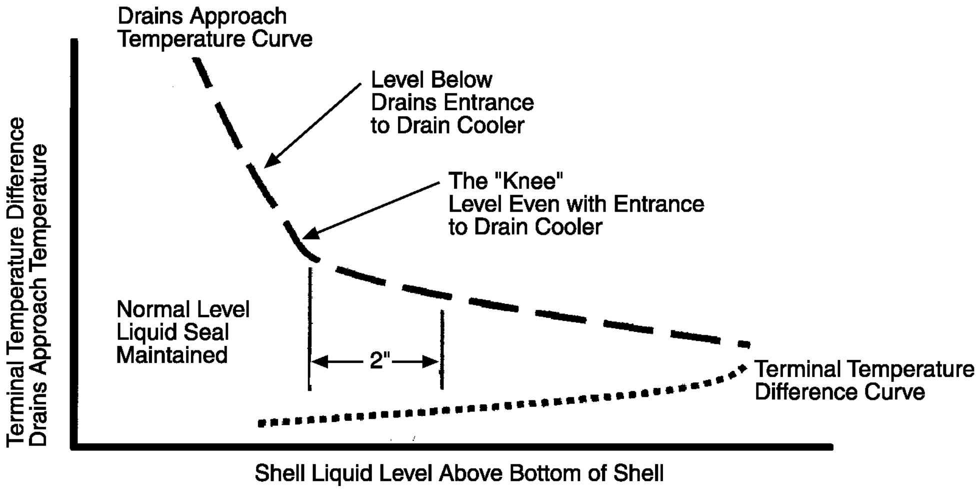

Figure 7-1
Temperature/Pressure Characteristics at Optimum Level

4. The level is then lowered incrementally, e.g., 1 inch (25.4 mm), repeating Step 2. Larger drops may be used at the beginning to expedite the test, with smaller drops at the about 2 inches (50.8 mm) above the expected knee. When data indicates that steam is entering the DCZ, i.e., when there is a rapid change in DCA and drain outlet pressure, along with an increase in flow noise and often a noticeable movement in the drains piping, data is recorded, and the level is returned to the previous one to prevent damage to the DCZ. The final data is then plotted.

5. The curve developed from the plotted data is then analyzed to determine the “critical” level for each heater. The critical level is where significant breaks or “knees” of heater pressure and temperature occur, as shown in Figure 7-1.

6. The feedwater heater level controllers are typically adjusted so that the water levels are maintained about 1.5 to 2 inches (38.1 to 50.8 mm) above the critical level determined from the graph. This has been found to not affect TTD significantly and provides margin for normal level fluctuations.

7.3.3 Precautions and Limitations

- While making level changes in the FWH, other FWHs in the same string should be monitored for unexpected changes. Failure to do this can lead to inadvertent level transients in feedwater heaters other than the one being tested.
- Final feedwater temperature should be monitored frequently to ensure temperature is within limits for existing power level.
- FWHs that use external drain coolers and level is maintained via loop seal are not tested by this methodology.

7.4 Tuning

7.4.1 When to Tune

In order to shorten outage times, some plants have performed FWH tuning at less than full power. However, to be effective and provide reliable level control, tuning must be done at the expected normal operating conditions, i.e., 100% power. There are two major reasons for this requirement.

- Process gain nonlinearities
- Internal flow dynamics of the FWH

Process gain nonlinearities, discussed in Section 3.2.2, refers to the fact that level control process gain is different at different power levels. This is because power level determines the extraction steam flow into the FWH, and extraction steam flow is the process load that affects level. Since overall loop gain must remain the same for optimal tuning, changing the process gain, i.e., changing the power level, after tuning means that the controller gain will no longer be valid.

Internal flow dynamics of the FWH refers to the effect that steam flow at various power levels has on level indication as well as on the distribution of condensate at the bottom of the heater, as discussed in Section 6.5.3. Localized steam velocity across the entrance to the top sensing line will have an aspirating effect, causing the pressure to be lower in the top of the equalizing leg than shell pressure and thus resulting in false high level. While good heater design should preclude this, the existence of the effect on any or all the sensing lines cannot be discounted. Another dynamic problem is the effect of steam flow on the actual level, which might cause it to be sloped either toward the channel head or in the opposite direction, or even sloped from the middle upward toward each end.

Key O&M Cost Point

Due to process gain nonlinearities and internal flow dynamics of the FWH, tuning will be effective and provide reliable level control at normal operating conditions only when it is performed at normal operating conditions, i.e., 100% power.

7.4.2 Tuning Method

Section 3 discussed tuning the level loop, which includes the FWHs and MSRDTs. It introduced two methods of tuning, manual-based and model-based. Many plants use a manual-based method, which as its name implies, means starting at known settings, e.g., gain zero or, more often, reset zero (no integral action), and then changing these settings using a set of rules based on experience. Manual-based methods tend to be favored by senior technicians who are comfortable with them and feel that they achieve satisfactory results. Tuning equipment for which previous settings are considered satisfactory is attractive, too, because it becomes simply a tweaking operation to arrive at the final settings.

The model-based methods use a manual test to reveal certain process parameters, which are converted into settings that theoretically provide optimal results. The quarter wave damping and minimum absolute integral error responses are examples of an optimal response. These model-based methods were developed from mathematical assumptions as well as empirical evaluations of the process. Model-based tuning is done with the controller in either manual or automatic; tuning in manual means open-loop tuning while tuning in automatic means closed-loop tuning. The most common method of model-based tuning is that developed by Ziegler and Nichols [11], when combined with the coefficients of Table 3-3 developed for non-self-regulating processes by Shinskey [10].

Both manual-based and model-based tuning are quite common in the nuclear power industry. While the choice must remain with the plant, this guide recommends the use of the model-based method if at all possible. Further, a closed-loop test provides the most information and should yield the best "first estimate." The bases for these recommendations as well as recommended alternatives follow.

7.4.3 Closed-Loop Test

Performing a closed-loop test requires the least amount of judgment in arriving at the key parameters needed to determine the estimated settings. For those plants that use the model-based approach, the closed-loop test is usually the only possibility, since the common types of pneumatic controllers can operate only in automatic.

As explained in Section 3.4.2.2, the integral time is set to have no effect (time at maximum) and the controller in automatic. Gain is increased until sustained, non-increasing oscillations are obtained (marginal stability). The gain required and the period of oscillations obtained are recorded and the settings determined using the coefficients in Table 3-3. These values are repeatable and can be used for tracking changes that take place and alert technicians to changes that may have detrimental consequences. As indicated above, these settings are "best estimates" because of model assumptions and inaccuracies with the controller and in determining the period. However, a starting point is quickly obtained and tweaking is small, so final values are obtained quickly, minimizing plant impact.

7.4.4 Open-Loop Test

The first alternative to the closed loop test is the open-loop test. It is not as easy as the closed-loop test, plus it requires a chart recorder to determine the response reaction curve and associated times and places the FWH in manual control. It also only obtains data about the process. With the open-loop test, the controller interaction is not known until the settings are in and the controller is in automatic, another reason for using the closed-loop test, which tests the whole loop, both process and controller. For some plants, however, manual control is preferable to automatic control with the levels oscillating up and down, so it becomes the test of choice for many plants.

7.4.5 Experience-Based Testing

Experience-based testing is still popular with the many technicians. Usually it involves automatic operation and uses the last settings as a guide to arrive at the final ones. Compared to the closed-loop testing above, there are few differences, except experience-based testing may or may not involve increasing gain to marginal stability. While experience-based testing may sound faster, the closed-loop test also can use the last settings to arrive at the point of marginal stability and, more importantly, determine the coefficients quickly. Appendix B provides a description of some manual methods of tuning.

7.5 High Level

High level protection should be reviewed. In most cases high level is attributed to one or more of the following:

- The drain system (consisting of normal and emergency/alternate drains) is not designed properly.
- The drain system is not operated properly because the design capability is not known or understood.
- One or more pieces of equipment malfunction.

7.5.1 Drain System Design

While nuclear power plants are built under the most exacting of design requirements, the secondary side falls outside of the NSSS vendor scope and requirements are not as strict. Therefore, based on the recommendations above, plants should review their design specifications and determine the capacity of both drain systems. Both the normal and the alternate drain must be sized for a minimum of full condensed extraction flow and all cascaded drain flows.

Key Technical Point

Both the normal and the alternate drain must be sized for a minimum of FULL condensed extraction flow and ALL cascaded drain flows.

During this calculation, consider different plant power levels. Flow depends not only on the drain size but also on the differential pressure that exists across the FWH, the extraction line, and the drain line. Although the extraction and cascaded drains flow drops, differential pressure reductions may be relatively greater. As late as 1996, one plant had a high level problem because of inadequate drainage at low power. As part of this review, verify that all alternate drains go to the condenser.

An easy but effective way to verify some of the above conditions is to observe the operation of the normal drains at full power. If they are operating at about 70–80%, the system is most likely properly designed. (These limits are for guidance if no design information is available. They allow good controllability with sufficient margin for routine transients, but they do not constitute requirements.)

Also, ensure that the alternate drain is never open during normal operations. If it cycles open and closed, then there is a control problem in either the process or control loop. If it is open continuously, then the normal drains are by definition undersized, which presents the following issues:

- The alternate drains may be undersized also.
- Alternate drains are backup to the normal drain in case of failure of the normal drain system. From a reliability perspective, this means they are both independent and redundant. Since both drains are required, then redundancy is lost and a high level trip is more likely when a normal drain fails.
- While it may be said that level is being controlled, the fact that the alternate drains are opened means that the level is well above design point and megawatts are being lost.

Additional information on drain system design for turbine water induction protection is found in Appendix D.

7.5.2 Drain System Operation

Operation of the drain systems, especially during startup and shutdown, requires close attention to their line up as well as an understanding their purpose and limitations. This information must be available and utilized especially if there are plant design problems still existing. Nothing can be assumed. For example in one of the events reviewed, one plant reported a reactor trip at about 75% because of feedwater heater string isolations. The plant was starting up and was using alternate drains. Causes of these problems included:

- The alternate drains were not capable of 100% power operation. The operators did not know this.
- The particular line up would result in high level alarms and heater drain string isolation when power increased above about 70% power.
- Operators did not have indication of level.

7.5.3 Equipment Malfunctions

Operational experience was reviewed to determine what issues cause reportable level challenges to feedwater heaters, moisture separator/reheaters, and associated drain tanks. The sources of this information included Operational Experience reports as well as U.S. NRC Notices and Licensee Event Reports. Sixty-seven reported events (see Appendix E) were identified that were considered related to feedwater heater, moisture/separator reheater, and drain tank level control. These 67 events were broken down as follows:

- High level issues including trip 47
- Unknown level issue 16
- Low level issues 4

The top three leading causes of these failures were broken down as follows:

- Level control valve malfunctions (mechanical) 12
- Tuning and/or controller 9
- Positioner 4

Nearly all causes related to equipment failures include aging. Earlier reviews have revealed similar equipment malfunctions that have resulted in high level trips. For example:

- Drain valve slow to open (mechanical problems
- Drain control valve closure (failed signal line)
- Heater control valve jammed
- Plugged loop seal (combined with tube leakage)
- Drain control valve coupling came apart (high vibration)
- Improperly installed level detector (revealed during plant power reduction)
- Heater normal drain valve failed closed (broken feedback assembly)
- Concurrent failures of heater drain tank high level dump control valve controller and motor operated isolation valve

Many of these failures occurred when the equipment was required to respond to a transient or the plant was in power ascension.

Therefore, preventive maintenance programs should be reviewed to ensure that critical feedwater heater control equipment is covered and appropriate frequencies applied. Guidelines that are available to assist in preparing a comprehensive maintenance program are shown in Table 7-2.

Table 7-2
Available EPRI Guidelines for PM Programs

Number	Title
NP-5479-R1	Application Guide for Check Valves [29]
NP-7412R1	Air Operated Valve Maintenance Guide [9]
TR-105663	Feedwater I&C Maintenance Guide [6]
TR-105852-V1	Valve Application, Maintenance, and Repair Guide, Volume 1 [5]
TR-105852-V2	Valve Application, Maintenance, and Repair Guide - In Situ State-of-the-Art Valve Welding Repair (Gate, Globe, & Check Valves), Volume 2 [30]
TR-105853	Application and Maintenance of Steam Traps [23]
TR-106857-1	PM Basis - Volume 1: Air Operated Valves [4]

Table 7-2 (cont.)
Available EPRI Guidelines for PM Programs

Number	Title
TR-106857-30	PM Basis - Volume 30: Relays – Control [24]
TR-106857-31	PM Basis - Volume 31: Relays – Timing [25]
TR-106857-32	PM Basis - Volume 32: Heat Exchangers [26]
TR-106857-33	PM Basis - Volume 33: Feedwater Heaters [27]
TR-106857-34	PM Basis - Volume 34: Condensers [28]
1003091	Valve Positioner Principles and Maintenance Guide [15]

7.6 Condition Monitoring

7.6.1 Walkdown

The walkdown inspection is done on-line and is a confirmation of the material condition of the feedwater heater level control system. This walkdown should be done frequently, and its scope should include the controller, control valve, positioner, associated piping, and electrical wiring. Material condition includes cleanliness, physical damage, mounting integrity, loose or missing parts, etc. This walkdown should be performed monthly. A recommended checklist should contain the following elements:

1. Observe the exterior to detect signs of physical damage to the housing, connections, pipe/tubing, hoses, and feedback linkage.

2. As appropriate, check for looseness of parts.

3. Inspect for air leaks. If possible, check all pneumatic connections with a soapsuds solution to detect leakage.

4. Observe the pressure gages and note if pressures are consistent with required supply pressures, expected signal pressure for valve position, and expected output pressure for valve position.

5. If the feedback cam position is visible, determine if its position is consistent with valve position.

6. Observe valve motion to see if response is consistent with changes in signal/output pressure variation and if control is erratic.

7. Verify that normal level control valves and not the alternates are controlling the level.

7.6.2 I&C Calibration Trending

In addition to the direct observation from the walkdown inspection, condition monitoring of the level control system is also a continuation of the calibration process. The goal of calibration or alignment is to ensure that the positioner is functioning correctly within design tolerances, e.g., start and stop points, travel, etc. It ensures that the fidelity between the input signal and the position of the valve is established. Therefore, for condition monitoring/preventive maintenance to be effective, calibration must be done carefully and consistently. Component performance on-line is masked by other parts of the control loop, and unless the failure is catastrophic, degradation will not attract attention. This means relying heavily on repeated calibrations. Persistent, significant calibration drifts can be used to identify the need for equipment repair or replacement.

7.6.3 AOV Preventive Maintenance

Preventive maintenance for air operated valves has been thoroughly documented in *Preventive Maintenance Basis - Volume 1: Air Operated Valves Reference* [4]. Additional guidance is found in *Air Operated Valve Maintenance Guide* [9]

8
TROUBLESHOOTING

8.1 Introduction

Troubleshooting is the systematic approach to data collection, failure analysis, and a test/measurement plan that results in high confidence that the complete cause of system/equipment degradation has been corrected and that the system/equipment has been restored to normal operation.

8.2 Formal Process

The formal process for troubleshooting has been documented in EPRI *System and Equipment Troubleshooting Guide* [14]. The process is divided into two main parts: 1) a preliminary evaluation and 2) the formal process of troubleshooting. The discussion of the preliminary evaluation describes the following:

1. Identifying the issue
2. Defining the problem
3. Determining and validating operating conditions
4. Comparing operating conditions to previous conditions to determine if the symptoms adversely affect system/component performance or reliability

If Step 4 is confirmed, then detailed troubleshooting begins.

8.3 Detailed Troubleshooting

Detailed troubleshooting consists of the following:

1. Performing a system walkdown and collecting additional system/component data
2. Identifying failure modes and system effects
3. Developing and implementing a troubleshooting plan
4. Determining if results identify the cause(s) of the problem and if so, performing the corrective actions; otherwise collecting additional data
5. Determining if the corrective actions restore performance and if so, confirming if root cause is discovered and documenting it; otherwise collecting additional data

This section of the guide supports Step 2, identifying failure modes and system effects.

8.4 Use of Troubleshooting Tables

Troubleshooting charts are a standard matrix showing effects and possible failure modes or mechanisms. The matrix approach is used since it shows common effects associated with each failure mode and therefore allows a means to confirm or refute failure modes. Additional matrices are included to facilitate troubleshooting of other components, e.g., control valve, positioner. Additional component troubleshooting information may be found in:

- *Valve Positioner Principles and Maintenance Guide* [15]
- *Solenoid Valve Maintenance and Application Guide* [8]
- *Air Operated Valve Maintenance Guide* [9]
- *Guidelines for Selection and Application of Power Plant Control Valves* [16] (Has some troubleshooting information, but is primarily useful for verifying sizing and characteristics.)

Table 8-1
Feedwater Heater Level Troubleshooting Matrix (Note 1)

Failure Effect→ Failure Mode ↓	Level High (Note 2)	Level Low (Note 2)	High Level Alarm	High Level Trip/FWH Isolation	Excessive Level Fluctuation (Sinusoid)	Excessive Level Fluctuation (Stepping)	Excessive Normal Level Control Valve Wear	Alternate Drains Fully Open (Note 3)	DCZ Noise	Drain Line Noise/ Movement	DCA Constantly High	TTD Constantly High
Normal drain valve failure to stroke open/is fully closed	X		X					X				X
Normal drain valve failure to fully retract/partly open	X		X					X				X
Normal drain valve fully open		X							X	X	X	
Normal drain valve erratic or jerky throttling/cycling					X	X						
Normal drain valve sluggish/slow			X		X	X		X	X	X		
Normal drain valve undersized	X		X					X				X

Table 8-1 (cont.)
Feedwater Heater Level Troubleshooting Matrix

Failure Effect→ Failure Mode ↓	Level High (Note 2)	Level Low (Note 2)	High Level Alarm	High Level Trip/FWH Isolation	Excessive Level Fluctuation (Sinusoid)	Excessive Level Fluctuation (Stepping)	Excessive Normal Level Control Valve Wear	Alternate Drains Fully Open (Note 3)	DCZ Noise	Drain Line Noise/ Movement	DCA Constantly High	TTD Constantly High
Alternate drain valve failure to stroke closed /is fully open		X							(Note 4)	(Note 4)	(Note 4)	
Alternate drain valve failure to fully retract/partly open				X								
Alternate drain valve fully closed				X								
Alternate drain valve erratic or jerky throttling/cycling					X	X						
Alternate drain valve sluggish/slow				X	X	X						
Alternate drain valve undersized				X								

Table 8-1 (cont.)
Feedwater Heater Level Troubleshooting Matrix

Failure Effect→ Failure Mode ↓	Level High (Note 2)	Level Low (Note 2)	High Level Alarm	High Level Trip/FWH Isolation	Excessive Level Fluctuation (Sinusoid)	Excessive Level Fluctuation (Stepping)	Excessive Normal Level Control Valve Wear	Alternate Drains Fully Open (Note 3)	DCZ Noise	Drain Line Noise/ Movement	DCA Constantly High	TTD Constantly High
Normal level transmitter failure (fail low)	X		X					X				
Normal level transmitter failure (fail high)		X							X		X	
Normal level transmitter failure (fail as is)	X	X	X					X	X		X	
Normal level transmitter calibration	X	X	X					X	X		X	
Normal level controller malfunction/ calibration/tuning	X	X	X		X		X	X			X	
Normal level setpoint incorrect/drift	X	X	X					X			X	
Normal level loop alignment (Note 5)	X	X	X					X			X	

Table 8-1 (cont.)
Feedwater Heater Level Troubleshooting Matrix

Failure Effect→ Failure Mode ↓	Level High (Note 2)	Level Low (Note 2)	High Level Alarm	High Level Trip/FWH Isolation	Excessive Level Fluctuation (Sinusoid)	Excessive Level Fluctuation (Stepping)	Excessive Normal Level Control Valve Wear	Alternate Drains Fully Open (Note 3)	DCZ Noise	Drain Line Noise/ Movement	DCA Constantly High	TTD Constantly High
Alternate level transmitter failure (fail low) (Note 6)				X								
Alternate level transmitter failure (fail high) (Note 6)												
Alternate level transmitter failure (fail as is) (Note 6)												
Alternate level transmitter calibration (Note 6)				X								
Alternate level controller malfunction/ calibration/tuning (Note 6)				X	X							
Alternate level setpoint incorrect/drift (Note 6)				X								

Table 8-1 (cont.)
Feedwater Heater Level Troubleshooting Matrix

Failure Effect→ Failure Mode ↓	Level High (Note 2)	Level Low (Note 2)	High Level Alarm	High Level Trip/FWH Isolation	Excessive Level Fluctuation (Sinusoid)	Excessive Level Fluctuation (Stepping)	Excessive Normal Level Control Valve Wear	Alternate Drains Fully Open (Note 3)	DCZ Noise	Drain Line Noise/ Movement	DCA Constantly High	TTD Constantly High
Alternate level loop alignment (Notes 5 and 6)				X								
Internal steam leakage to DCZ										X	X	
Incoming drips or extraction steam flow fluctuating					X	X	X			X		
Level signal noisy (Note 7)					X		X					
High level setpoint incorrect/drift				X								
Flashing in drain line							X		(Note 8)	X	(Note 8)	

Table 8-1 (cont.)
Feedwater Heater Level Troubleshooting Matrix

Failure Effect→ Failure Mode ↓	Level High (Note 2)	Level Low (Note 2)	High Level Alarm	High Level Trip/FWH Isolation	Excessive Level Fluctuation (Sinusoid)	Excessive Level Fluctuation (Stepping)	Excessive Normal Level Control Valve Wear	Alternate Drains Fully Open (Note 3)	DCZ Noise	Drain Line Noise/ Movement	DCA Constantly High	TTD Constantly High
Inadequate normal drain valve backpressure/ excessive line pressure drop									X	X		
Normal drain valve oversized					X		X					

Notes:
1. Table Assumptions
    a. Normal drain valve is fail closed, air-to-open.
    b. Alternate drain valve is fail open, air-to-close.
    c. High level alarm setpoint same as alternate drain valve open setpoint (unless by design alternate drain valve uses a controller to maintain elevated level, then alarm is above design controlled range).
    d. High level alarm setpoint is higher that normal high level limit.
    e. High level trip setpoint is higher than high level alarm.
2. FWH level is above or below normal range.
3. Assumes that alternate drains are unexpectedly open.
4. Assumes normal and alternate drains share common drain outlet.
5. Level value range and inputs/outputs of loop components are consistent with process.
6. Assumes alternate level control maintaining level and normal level control disabled/inoperative.
7. Flashing occurring at level surface.
8. Sometimes is present.

Table 8-2
Level Control Valve Troubleshooting Matrix [9]

Failure Effect→ Failure Mode ↓	Erratic or Jerky Throttling	Failure to Fully Retract	Failure to Fully Extend	Cycling	Failure to Stroke	Sluggish /Slow	Slow in Increasing Air Pressure Direction	Slow in Decreasing Air Pressure Direction
Actuator supply pressure low		X	X		X	X		
Actuator supply pressure high	X				X[1]			
Actuator supply erratic	X			X				
Unsteady signal	X			X				
Improper bench set		X	X					
Positioner (See table 8-3)	X				X	X	X	X
Wrong travel stops/ calibration		X	X					
Increased packing friction						X		
Actuator spring too large							X	
Actuator spring too small								X
Air leak (diaphragm, stem seal, or case joint)							X	
Leaks		X	X		X	X		

Table 8-2 (cont.)
Level Control Valve Troubleshooting Matrix [9]

Failure Effect→ Failure Mode ↓	Erratic or Jerky Throttling	Failure to Fully Retract	Failure to Fully Extend	Cycling	Failure to Stroke	Sluggish /Slow	Slow in Increasing Air Pressure Direction	Slow in Decreasing Air Pressure Direction
Solenoid valve failure				X	X	X		
Air supply tubing crimped, too small						X		
Actuator too large						X		
Piston lubrication[2]		X	X		X	X		
Damage cylinder or piston rings/ seals		X	X	X	X	X		

Table 8-3
Positioner Troubleshooting Matrix [14]

Effect	Failure Mode
Erratic or jerky throttling	Feedback linkage from control valve element loose Excessive packing friction Positioner output pressure too low Internal air leaks including pressure gauges Output signal Generator spool valve sticking
Failure to stroke (Will not move from minimum travel position)	Leak in signal circuit Cam reversed Airlines reversed(double acting actuator) or airline in wrong port (single acting actuator) Air supply starved (line too small or crimped) Output relay or pilot stuck/not functioning properly Actuator handwheel in wrong position
Failure to stroke (Will not move from one end of stroke)	Output signal generator (pneumatic relay) leaking Supply breakdown orifice to nozzle-flapper chamber plugged Air line(s) in wrong port Actuator handwheel in wrong position

Table 8-3 (cont.)
Positioner Troubleshooting Matrix [14]

Effect	Failure Mode
Slow in increasing or decreasing air pressure direction	Output pressure too high or too low Blockage in output lines or output valves Pneumatic relay not responding correctly Booster not adjusted properly
Positioner will not calibrate for full range	Leak in signal circuit Improper feedback alignment Motion balance positioner not properly balanced or pre-alignment problem Actuator air leakage Air supply pressure incorrect Internal air leaks External handwheel incorrectly positioned Positioner in bypass Worn cam and/or cam roller Pilot valve or output relay not responding properly Starved air supply Vent paths blocked Cam not installed properly Wrong range spring
Control valve oscillates during checkout or calibration	Feedback linkage from control valve element loose Positioner gain too high Positioner output pressure too low Booster not adjusted properly Excessive packing friction Valve plug/stem separation Internal air leaks in pressure gauges Worn cam and/or cam roller
Excessive Air Consumption	Leakage at joints of manifold assembly or pneumatic relay assembly

9
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A
GLOSSARY

Amplifier. A component that allows an input signal to control a power source that is independent of the signal.

Backlash. The movement in the output that is observed after a motion has been reversed. It is result of looseness, free-play, etc.

Beam. The summing point controller of control valve positioner.

Bellows. A flexible cylinder that expands or contracts to convert pressure to force or motion. It is often used in positioners to position the beam.

Bench set. A specification that is used to verify proper actuator operation. Bench set is expressed as the pressure range from the start of the actuator stroke to the valve's rated travel.

Calibration. The act of adjusting the output of a device so that it corresponds to the value of the input of the device. In positioner calibration, zero, span and crossover (balance) pressure are the primary calibration adjustments.

Closed-loop control. Pertaining to a system with a feedback type of control, such that the output is used to modify the input.

Controller - A device that operates automatically to regulate a controlled variable to make it equal the setpoint. An automatic controller varies its output signal in response to changes in the controlled variable. Alternately it is that part of the control loop that takes the output of the summing point (error) and produces an output signal response for the final control element that will minimize the error.

Controlled variable. The variable of the process that is to be controlled. It may or may not be the manipulated variable. See Table 2-1.

Dead band. Dead band is the range that the input changes before the output begins to change after the input has been reversed. One of causes dead band is backlash, which is the result of looseness, free-play, etc.

Dead time. The time required for a system to begin to respond to an input. Compare to lag.

Derivative mode. One of the three basic control modes which produces a change in the output signal from a controller as a function of the time rate of change of the measured variable with respect to the setpoint. It acts only when the variable is changing and ceases to act when the variable stops moving. It is also know as rate action or rate response.

Direct-acting actuator. An actuator in which the actuator stem extends toward the control valve in response to an increasing input signal. Used for fail-open valve applications, because the loss of air supply will result in the valve going open.

Direct-acting positioner. A positioner that provides increasing output pressure in response to an increasing input signal.

Directional control valve. A valve that provides porting that allows it to direct flow to an actuator that causes the associated valve to move in a certain direction. Sometimes known as a pilot valve.

Double-acting positioner. A positioner that has two relays, typically used with a double-acting and spring bias designs.

Dynamic error. A special term that equals the sum of hysteresis and dead band when they measured during dynamic or moving conditions.

Dynamic response. The response characteristics of an element, including phase shift and dynamic attenuation, observed as the frequency of the input is varied.

E/P converter. A transducer that uses voltage (typically 0-10v) for an input and pressure for an output. See I/P converter, transducer.

Equal percentage characteristic. The inherent flow characteristic, which for equal increments of rated travel, will give equal percentage changes of the flow coefficient Cv. (See Figure C-1)

Error. The output of the summing point. The difference between the setpoint value and measured value.

Fail close. See reverse-acting actuator.

Fail open. See direct-acting actuator.

Feedback. A feature of control loops in which the output signal of a process is fed back through a mechanism that modifies the input to the controller. The feedback may be negative if it tends to decrease the output or positive if it tends to increase the output.

Feedback element. The device in a control loop that acts to modify the input to the controller.

Final control element. The device that directly changes the value of the manipulated variable of a control loop.

First-point heater. The last feedwater heater to raise the temperature of the feedwater. So-called because it receives extraction steam from the first extraction point of the turbine. Also known as the *top heater*.

Flow characteristic. The relation between the flow through a valve and the percent rated travel as the latter is varied from 0 to 100%. This is a special term. It should always be designated as inherent flow characteristic or installed flow characteristic. Common flow characteristics are linear, equal percentage, and quick opening. See inherent flow characteristic and installed flow characteristic. (See Figure C-1)

Flow coefficient, fluid (Cv). The number of US gallons per minute (gpm) of 60°F water that will flow through an orifice (valve) with a one pound per square inch (psi) pressure drop.

Gain. An expression used to denote device output as related to input. Gain is usually a dimensionless value.

Hysteresis. The phenomenon exhibited by a system whose state depends on its previous history. It is seen as a nonlinearity of an output resulting from application of an input in a different direction or sense. Particularly it is the different device response that occurs when the force is reversed or applied in a different direction.

Inherent flow characteristic. A description of how flow in a valve varies with pressure drop across the valve in which the total system pressure drop occurs only in the valve.

Input. The signal applied to a device, i.e., a controller, that will result in an output.

Installed flow characteristic. A description of how flow in a valve varies with pressure drop in the valve in which the total system pressure drop is divided between the valve and the system

Integral mode. One of the three basis control modes that produces a continuous change in the output signal from a controller as long as there exists a deviation of the measured variable from the setpoint. The rate of change in the output signal depends on the amount of deviation, the proportional bandwidth, and the setting of the integral mode adjustment. The output ceases to change when the variable returns to the setpoint. It normally results in a new final output than what existed before the action began. By so doing, it eliminates offset. This mode is also known as reset response. The adjustment for integral or reset may be calibrated either in repeats per minute or minutes per repeat.

I/P converter. A transducer that uses current (typically 4-20ma) for an input and pressure for an output. See E/P converter, transducer.

Lag. The time it takes a device to achieve some output value after it begins to respond. Normally this is expressed as a time constant, τ (tau), which is the time to reach 63.2% of the final value. Compare to dead time.

Limit cycle. A nonlinear control loop instability. Can be caused by friction-related dead band in the control valve, e.g., stiction.

Linear characteristic. For control valves, a characteristic that produces a percentage of maximum Cv that is directly proportional to valve stem position as a percentage of full travel.

Linear flow characteristic. An inherent flow characteristic that can be represented ideally by a straight line on a rectangular plot of flow versus percent rated travel. (Equal increments of travel yield equal increments of flow at a constant pressure drop.) (See Figure C-1)

Linear process. A process in which gain is constant regardless of load.

Manipulated variable. The process input (quantity, property, or condition) that is adjusted to maintain the controlled variable at a desired setpoint. (See Table 2-1)

Measured variable. The physical quantity, property, or condition that is to be measured, e.g., temperature, pressure, flow, level, speed, weight, etc. It is a function of the controlled variable.

Nonlinear process. A process in which gain changes at different loads or flow conditions.

Nozzle-flapper amplifier. A pneumatic signal amplifier in which changes the position of the flapper relative to the nozzle results in changes in an output pressure.

Offset. The difference between the controlled variable and the setpoint that occurs when a control loop operates at a point different from what it was calibrated for. It occurs with control loops that do not use integral mode control.

Output. A particular process quantity or variable that has been identified to be the result of the values or actions of one or more other process values defined as input.

Phase shift. For a device, the amount of time that an output lags behind an input. One of the causes is dead band.

Pilot valve. See directional control valve.

Pneumatic. Pertaining to or operated by air or other gas.

Positioner. A device that compares the actual valve position with desired position with respect to an input signal and adjusts actuator-loading pressure until the desired valve position is attained. The desired position has a predetermined relationship to the input signal.

Pressure drop. The difference between the upstream pressure and downstream pressure that represents the amount of flow stream energy that the control valve must be able to absorb or withstand.

Pressure drop, maximum allowable. The maximum flowing or shutoff pressure drop that a control valve can absorb or withstand. While maximum inlet pressure is commonly dictated by the valve body, the maximum allowable pressure drop is generally limited by the internal controlling components (liner, disk, shaft, bearings, seals, etc.) The maximum allowable pressure drop may apply to the pressure drop while flowing process fluids are at shut off.

Process gain (static). The dimensionless ratio of the magnitude of change in the process variable (PV) to the magnitude of the change in input to the process. The change in input is usually measured at the controller output (CO) and therefore process gain is equal to PV/CO where PV and CO are in the same units.

Proportional band. The change in input required to produce a full-range in output due to proportional control action.

Proportional control mode. The most basis control mode in which the controller output signal is proportional to the amount of deviation between the measured variable and the setpoint, i.e., error. The adjustment for proportional response is either in terms of gain or proportional band (equals reciprocal of gain times 100).

Quick opening. A characteristic that, for equal changes in stem position, provides a large change in Cv at low lifts and smaller changes in Cv at high lifts. (See Figure C-1)

Quick opening characteristic. An inherent flow characteristic in which there is near maximum flow with minimum travel.

Range. The region between the upper and lower values of the variable in question, expressed in terms of the lower and upper range values, e.g., 3-15 psig, 4-20 ma, etc. See span.

Rangeability. The ratio of maximum to minimum flow within which the deviation from the specified inherent flow characteristic does not exceed some stated limit. For example for a linear flow characteristic, the range of flows for which the flow characteristic remains linear. This is usually somewhere in the central part of valve lift. Rangeability is expressed as the ratio of the maximum controllable flow coefficient to the minimum controllable flow coefficient of a control valve.

Rate action (rate response). See derivative mode.

Rated Cv. The value of Cv at the rated full-open position.

Relay. A device that receives one or more signals, modifies these signals, and/or changes their form (see transducer) to produce one or more outputs.

Relay, pneumatic. A pneumatic power amplifier in which change in input pressure result in changes in the position of exhaust and supply valves that control a separate supply valve.

Reset (response). See Integral mode.

Reverse-acting actuator. An actuator construction in which the actuator stem retracts away from the control valve with increasing pressure. Used for fail-close valve applications, because the loss of air supply will result in the valve going closed.

Saturation (1). The point in an operating range at which a change in input no longer causes an output change.

Saturation (2). The thermodynamic condition in which the fluid has been completely converted to a vapor and which the addition of heat will cause the temperature of the vapor to rise. Usually used with the corresponding unique combination of temperature and pressure.

Sensor. A transducer that is used to measure or monitor a physical variable.

Setpoint. The desired value for the controlled variable. The setpoint is an input variable that can be manually or automatically set and is expressed in the same units as the controlled variable, e.g., degrees F, psig, etc.

Single-acting positioner. A positioner with only one relay, typically used with spring-return actuator designs.

Span. The difference between the upper and lower range values variable in question, expressed in terms of a single value, e.g., 12 psig, 16 ma, etc. See range.

Span adjustment. The calibration procedure that establishes the control valve position desired when the input signal is at the maximum value of the input signal range. (See zero adjustment.)

Split range. A technique in which one controller is used to operate two or more final control elements.

Static gain. The ratio of change of steady-state output to a change in input.

Static open-loop gain. The static gain of an entire system, measured by opening the loop and determining the ratio of the change in output to a change in input. It is the product of the gains of all system elements.

Stiction. A term that describes the effect of the difference in static and dynamic coefficient of friction on movement of a control valve stem after it receives a signal to move. Due to packing friction, the stem does not move immediately and is delayed until the stem force increases sufficiently. However, to maintain the movement, less force is required due to the lower coefficient, and the stem position overshoots the required position. This results in a cycling of the control valve around the required position, which is called *limit cycle.*

Stiffness. The resistance of the actuator to forces that tend to destabilize its position.

Summing point. Any point at which the signal are added algebraically. In a control valve positioner, summing is usually accomplished with a beam. It can also be a diaphragm.

Top heater. See first-point heater.

Transducer. A device that accepts an input in one form (pressure, electrical current, etc.) and provides a corresponding output in another form.

Zero adjustment. The calibration procedure performed to establish the desired valve position when the input signal is at the minimum value of the input signal range. (See span adjustment.)

B
EXPERIENCE-BASED TUNING METHODS

B.1 Introduction

The following methods have been used successfully at utilities in place of classical model testing. A cursory review indicates that the methodology is the same as the Ziegler-Nichols closed-loop test (ultimate sensitivity, ultimate period), except the final adjustments use different coefficients and do not rely on the ultimate period to determine reset and rate. They are presented only for information and comparison.

B.1.1 Plant A

1. Place controller in manual mode.

2. Remove integral and derivative actions.

3. Adjust gain to 0.5 (PB = 200%).

4. Place controller in automatic.

5. Insert a step change in process by adjusting setpoint ≈10%.

6. Observe process variable for oscillations.

7. Continue step changes by changing gain by a factor of 2 each time until sustained oscillations are obtained as shown in Figure 5-3. This is the critical point. These step changes should be from the same point, by the same amount, and in the same direction whenever possible to allow for an accurate comparison after each adjustment.

8. When critical point is determined, adjust gain to 2/3 of final (critical) value, i.e., final value 3, adjust gain to 2 or multiply PB by 1.5, i.e., final value 2, adjust PB to 3.

9. With gain at calculated value, adjust reset or integral time to return process variable to setpoint value in a minimum time without upsetting stability of system (i.e., raise reset until stability is affected then back off until a stable control is established).

10. Lower derivative or rate time until oscillations occur, as observed on input signal gauge, then raise rate time until oscillations cease.

11. Raise gain by approximately 5% (lower PB by 5%).

12. Repeat steps 10 and 11 until a combination of rate and gain (proportional band) is obtained that produces a shorter stabilization time with less upset to process.

13. Gain should not be greater than 1.7 critical nor PB less than 1.7 after step 12 is completed.

B.1.2 Plant B

1. Used with Masoneilan or Magnatrol PI controllers
   - With controller in automatic, adjust setpoint to the plant specific value for the process.
   - Adjust reset to low setting (0.2 to 2 repeats/minute depending on process), which does not interfere with proportional band (gain).
   - Adjust (narrow) proportional band setting to as narrow a value as the process will permit. (Typically, narrow the band until cycling just occurs.)
   - Adjust (widen) proportional band setting by the following:
     – For Masoneilan controllers – approximately 50% (i.e., if a setting of 4 was as narrow as the system would allow, then set the knob to 6).
     – For Magnatrol controllers – approximately 20% (i.e., if a setting of 4 was as narrow as the system would allow, then set the knob to 4.8).
   - Slowly turn reset knob clockwise (increase reset rate) until cycling occurs.
   - Observe setting of reset knob and adjust reset knob to ½ of the observed settings.

2. Used with Masoneilan or Magnatrol P controllers:
   - With controller in automatic, adjust setpoint to the plant specific value for the process.
   - Adjust (narrow) proportional band setting to as narrow a value as the process will permit. (Typically, narrow the band until cycling just occurs.)
   - Adjust (widen) proportional band setting by the following:
     – For Masoneilan controllers – approximately 50% (i.e., if a setting of 4 was as narrow as the system would allow, then set the knob to 6).
     – For Magnatrol controllers – approximately 20% (i.e., if a setting of 4 was as narrow as the system would allow, then set the knob to 4.8).

C
CONTROL LOOP NONLINEARITY

C.1 Control Loop Design Assumption

All control loop designs and analyses assume that the loop is linear. A linear control loop responds to its input signal with the same dynamic response—gain, time constants (lag), and dead time— regardless of the size of the change in the input signal. Sensor/transmitters, comparators, and controllers are electrical devices and by design can be made essentially linear. A well-known example is the use of the square-root extractor that converts the delta P of a flow orifice to an output directly proportional to flow.

If the loop is not linear, then the controller settings are only optimal for a particular system response, i.e., a particular dead time and lag. If the process conditions differ, e.g., the disturbance changes, the response to the output of the controller will be different. If this means longer dead time or lag, it may result in instability and loss of control.

C.2 Control Valve Inherent and Installed Flow Characteristics

All control valves can be described by a flow characteristic curve that relates flow (as a percentage of full flow) to the stroke of the valve (as a percentage of full stroke). Figure C-1 shows three of the more common types that are commercially available. It is important to understand that these *inherent* characteristics curves are based on the valve being the only source of pressure drop in the line. When other sources of pressure drop become larger with flow (or with a centrifugal pump supplying motive force), these curves will change for the installed valve, tending to look more like the curves that are to the left of the inherent curve. In other words, equal percentage tends toward linear, etc. It is these *installed* characteristic curves that must be considered when determining the linearity of the flow versus travel. In a properly designed system, the installed characteristic curve will be linear.

To assure uniform control loop stability through the anticipated valve operating ranges, valve characteristics should be specified so that the valve response will match the dynamics of the process. A quick opening valve characteristic is desirable for on-off control. A linear characteristic (flow rate directly proportional to valve travel) is good for most flow control and liquid level control systems. An equal percentage characteristic is best suited to pressure control or flow control systems with wide-swinging pressure drops. Table C-1 gives the limitations on level control characteristics.

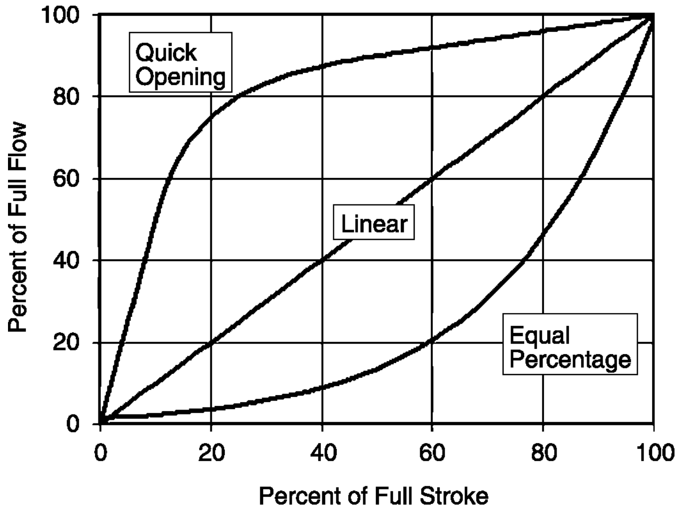

Figure C-1
Valve Flow Characteristics

Table C-1
Limitations on Level Control Valve Characteristics

Control Valve Pressure Drop	Best Inherent Characteristic
Constant delta pressure	Linear
Decreasing delta pressure with increasing load, delta pressure at maximum load > 20% of minimum load delta pressure	Linear
Decreasing delta pressure with increasing load, delta pressure at maximum load < 20% of minimum load delta pressure	Equal percentage
Increasing delta pressure with increasing load, delta pressure at maximum load < 200% of minimum load delta pressure	Linear
Increasing delta pressure with increasing load, delta pressure at maximum load > 200% of minimum load delta pressure	Quick opening

C.3 Hysteresis/Dead Band/Stem Friction

Hysteresis results from the fact that all real devices bend, twist, or otherwise deform when they are stressed. Therefore, if they are forced in one direction, they will bend in one direction and if forced in another direction, they will bend in another direction. Hysteresis is part of the dynamic error and is a result of the deformation of both the positioner and the valve actuator. Hysteresis, however, does not dominate the dynamic error, unless something is wrong. In fact, hysteresis is usually quite small. The dominant factor in the dynamic error is dead band.

Dead band and stem friction effects are not only a cause of dead time but also are a cause of nonlinearity. Dead band is the range the input changes before the output begins to change after the input has been reversed. Nonlinearity occurs since the response to the changes is different (though predictable) each time the stem changes direction. Since stem friction also causes the same induced dead time, it is similar to dead band as a cause of nonlinearity.

D
PREVENTING TURBINE WATER INDUCTION

D.1 Introduction

This appendix contains information that may be helpful in reviewing plant design, operations and maintenance for turbine water induction (TWI) vulnerability.

Turbine Steam Path Damage: Theory and Practice, Volume 2, Section 28 [2] provides several recommendations to prevent induction including isolation of the FWH. *Recommended Practices for Prevention of Water Damage to Steam Turbines Used for Electric Power Generation* [3] provides additional design requirements applicable to preventing high level. The recommendations have been combined in the following paragraphs.

D.2 Design

- Two independent means of automatically preventing water from entering the turbine from extraction systems are needed, including an automatic drain system from the heater shell.
- Suitable alarms should provide operators with indication that first and second lines of defense have been called into operation.
- The alternate (emergency) drain is to discharge directly to the condenser.
- Both the normal and the alternate drain should be sized for a minimum of full condensed extraction flow and all cascaded drain flows.
- While *Practices* provides for the normal and alternate drains to come from the same drain line, i.e., the alternate line shares the same outlet as the normal, it may be desirable to connect the alternate directly to the heater shell ahead of the drain cooler to assure positive drainage. Another reason for this is that the combination of normal and alternate flows may cause flashing in the drain cooling zone due to high fluid velocities.
- The speed of operation of the automatic isolation valves depends on the volume margin between the isolation level and the isolation valves. That is, the isolation should be complete before the water reaches the valve. *Practices* recommends that the flow to be used should be the larger of:
  - Flow from two ruptured tubes [double-ended guillotine break (DEGB)]
  - Volume equivalent to 10% of the tube side flow

  It is assumed that the above flows are in addition to the normal and cascading drain flows of normal operations.

- The alarms provided to the operators for both the level requiring the opening of the alternate drain controls and the level for isolation.
- The physical arrangement of the level alarms and drain piping is to be such as to preclude false actuations from level surges during startup and normal operations. Sensing lines should be such that a single failure will not prevent protective actions.

D.3 Operation

- Prepare specific operating instructions for each unit in response to high level alarms.
- Operators should investigate all alarms and isolate the source of water.
- Do not operate a heater if some protective devices are inoperable unless equal protection is assured by other provisions.
- When a heater is returned to service, the operator should check that the heater shell pressure is lower than the corresponding turbine stage pressure before opening the extraction line shutoff valve. (This is an important point and has been the source of many problems.)

D.4 Maintenance

- Detect and plug leaking feedwater heater tubes. Acoustic detection systems are available to detect heater leaks.
- Test feedwater level control/alarms and switches monthly for proper operation.

E OPERATIONAL EXPERIENCE

E.1 Introduction

As discussed and analyzed in Section 7, operational experience was reviewed to determine what issues caused reportable level challenges to feedwater heater, moisture separator/reheaters, and associated drain tanks. The sources of this information included Operational Experience reports as well as U.S. NRC Notices and Licensee Event Reports. Sixty-seven reported events were identified that were considered related to feedwater heater, moisture/separator reheaters and drain tank level control. Below is a table of these 67 events.

E.2 Table of Events

Table E-1 of event summaries begins on the next page. Events are from Operational Experience (OE), Operating Plant Experience Code (OPEC), or Significant Operating Experience Report (SOER) data base.

Table E-1
Operating Events

Date	Event (See Para E.2)	Event Description
821217	SOER 83-7	Adjustments to feedwater heater level transmitter resulted in an erroneous hi-level signal, causing a turbine trip and subsequent reactor trip. Technician unaware that transmitter fed turbine trip logic.
900106	OE3834	During main turbine combined intermediate valves test , moisture separator experienced a high level condition. Associated dump valve opened, but not in time to prevent a turbine trip on moisture separator high level followed by reactor scram. Primary cause attributed to less than optimal tuning.
910530	OE4699	While swapping the 1A and 1D Heater Drain Pumps, the 15A and 14A low pressure feedwater heaters became erratic. Power was reduced to 92% to maintain condensate booster pump suction pressure above 80 psig. Cause was malfunction of normal level controller on 15A and less than optimal tuning of 14A normal level controller.
930611	OE6063	FWH high-high water level signal caused a turbine trip, resulting in a reactor trip from 16% power. Trip occurred because the FWH high level dump (HLD) valve hand switches were in the normal (SHUT) position vice their startup position (OPEN). The previous day both units had tripped on a partial loss of offsite power.
930704	OE6422	Extraction steam isolation valve unexpected shut twice. First time was during a transient. Second time was event that required plant to reduce power. Valve would not open remote manual. Attributed to false close signal from level switch caused was build up of mercury around probe tips. This was determined to be the result of high temperature environment (450F).
940509	OE6627	Reactor scram due to turbine control valve (TCV) fast closure scram signal caused by high level in the “C” moisture separator (MS). During turbine valve testing, the MS level transmitter for the normal level control valve failed to sense an increasing level in the MS drain tank due to a shift in calibration of the transmitter. This allowed the level in the MS drain tank to increase to the emergency dump valve opening setpoint. The emergency dump valve level transmitter sent an open signal to the emergency dump valve level, but the controller failed to bleed the air off the emergency dump valve diaphragm which allows the valve to open. Consequently, the high MS level trip point was reached and tripped the turbine, which resulted in the TCV fast closure scram.

Table E-1 (cont.)
Operating Events

Date	Event (See Para E.2)	Event Description
960725	OE8419	An EHC transient caused a momentary variation in Main Turbine pressure. This caused a series of FWH isolations beginning with 2C FWH. When the 5B and 5C FWHs isolated feedwater temperature dropped to 336F and the unit automatically scrammed due to high neutron flux signal. Five days after bringing unit back on line, the C LP FWH string isolated during turbine valve testing caused by the 2C FWH drain valve actuator failing to open valve fully due to actuator stem seal partial failure. This resulted in a reactor scram. Also the setpoint of the 2C FWH dump valve level controller was adjusted to enable it to open earlier on increasing FWH level to avoid a high-high level condition and subsequent feedwater string isolation. While bringing the unit back to full power following the second scram described above, a high level condition alarm occurred intermittently on the 2C FWH at approximately 97% power. It was determined that the controller setpoint was inadvertently set in the wrong direction and caused a C LP FWH string isolation. The setpoint was restored to as found conditions and the string was restored.
970526	OE8604	During troubleshooting, moisture separator/reheater (MSR) re-heating steam drain tank level oscillations (later determined to be caused by the failure of the feedback arm on reheater drain tank level control valve), an isolation signal for the MSR heating steam was received with the subsequent isolation of only one of the two MSR Supply valves (later determined to be caused by an intermittent failure of the air actuator solenoid valve). This resulted in imbalanced reheat to the steam supply to the Low Pressure Turbine Rotors and an increasing differential temperature across the LP rotors. Operations reopened the MSR steam supply valve resulting in a steam pressure wave traveling into the MSR causing the MSR Pass Partition Plate to fail allowing reheat steam to pass directly into the MSR drain tank without providing appreciable reheating of the Cold Reheat Steam.
970708	6272	Power hold at 30% to investigate a control problem with the MSR drain tank level control valve.
970804	18216	Load reduction to 98% for FW heater 1B level control valve repair.
970807	14490	The unit was at 100% power when an automatic turbine trip, reactor trip, and FW isolation occurred due to high SG level. The FW regulating valve for SG A failed open during replacement of a resistor block in the SG level control circuit by I&C technicians. The spurious FW regulating valve opening resulted in a rapid rise in SG level. SG level shrinkage from the secondary pressure rise resulted in the expected automatic start of all three AFW pumps. The root cause of the trip was determined to be the existence of excess solder on a circuit card in the SG FW flow control module. The excess solder came in contact with the module chassis creating an internal ground on the FW control loop. Ground current initiated a full open demand signal to the A main FW regulating valve and prevented operators from taking manual control of the valve. (LER# 9725)

Table E-1 (cont.)
Operating Events

Date	Event (See Para E.2)	Event Description
970907	35028	Load reduction due to a high level alarm on FW heater 5C, which was caused by an air relay failure on the valve positioner for 2EES-LV5C.
971011	10053	Power hold at 63% to repair FW heater 3A drain level control valve.
971115	27389	Load reduction to 80% due to level control valve problems on FW heater 4C.
971206	3256	An automatic reactor scram occurred at 75% power as a result of a turbine trip due to high reactor water level experienced during power ascension following an outage. The cause of the scram was the failure of the A FW regulating valve in the full open position due to misalignment of the valve clip inside the pilot valve assembly of the positioner. (LER# 9726)
980222	30474	The unit was operating at 100% power when an automatic reactor trip occurred on low SG #2 water level due to a decrease in main FW flow. In addition, the unit received an ESFAS actuation of AFW on low SG #2 water level. On receipt of the AFW actuation, both emergency diesel generators started and ran unloaded as designed. The event was caused by the spurious closing of the economizer regulating valve by approximately 25%. The apparent root cause of the economizer regulating valve closure was attributed to a failure of the dynamic compensator card in the compensated level signal circuitry, which was an input to the FW control system #2 master controller. (LER# 9802)
980308	36921	The unit was at 100% power and had commenced feed and bleed operations on the Turbine Plant Cooling Water (TPCW) system. Both TPCW pumps tripped due to low-low level indication in the TPCW head tank. Shortly thereafter, the turbine tripped on high primary water temperature. The reactor automatically tripped on turbine trip as designed. AFW automatically actuated. The event was a result of a low level switch failure in the TPCW makeup valve. The cause of the switch failure could not be determined. (LER# 9802)
980531	35708	Power hold at 90% for investigation of #2 FW heater high level.
980602	OE9101	During walkdowns at 22% power and prior to placing the feedwater heaters in service, operators noted visible movement of piping and noise in the area of the 'B' train drains from the moisture separator drain tank. The apparent cause of the event was controllers installed 6 months earlier not set close enough to the optimum control band for the low operating power level.

Table E-1 (cont.)
Operating Events

Date	Event (See Para E.2)	Event Description
980609	4967	While at 65% power, during power reduction in preparation for single loop operation in response to a recirculating pump MG set high bearing oil temperature, the reactor scrammed due to a turbine trip on high water level. The A FW level control valve would not close to accommodate the reduced power due to foreign material, a cap screw, lodged in the valve. The valve could not close beyond approximately 42% from its full open position. The running FW pumps tripped on high water level and reactor water level decreased to the low level setpoint such that PCIS Groups 2, 3, and 5 were actuated. About 15 minutes after the scram, the C FW pump was started but tripped on low indicated minimum flow. Following the trip of the C FW pump, the A and B FW pumps attempted to simultaneously auto-start, which caused an overcurrent condition on 4KV bus 1 and subsequently tripped the supply breaker to 4KV bus 1 as well as the feeder breaker to 4KV bus 3. This resulted in a loss of 4KV power to the A and B FW pumps, the A condensate pump, and the A recirculation pump, plus 4KV busses 6, 8, and 11. Due to the loss of power, the B diesel generator started and assumed the loads on 4KV bus 3 and 480VAC bus 8. When power was restored, bus 6 was cross-tied to bus 7, the turbine bypass valves ramped open which caused a high steam flow scram signal and Group 1 PCIS isolation. level control was maintained using RCIC. (LER# 9816)
980831	OE9324	A Main Turbine hot reheat steam pressure switch inadvertently actuated. The actuation of this switch opened the high level control valves for the 1st stage reheater drain tanks and the MSR drain tanks, resulting in a reduction of extraction flow to the heater drain tanks. The switch actuation was caused by an accumulation of corrosion products due to moisture accumulation within the microswitch.
981009	1030	Load reduction due to a FW heater #124 high level trip.
981016	OE9475	High level alarms were received on both the 5B and 6B Feedwater heaters. Prior to this, extraction steam to the 4B and 5B heaters had been secured due to an operational failure of 4B level control valve. Six and a half hours later, the HP Turbine B Drain to 4B Non-Return Valve failed to go to required mid-position with a Hi-Hi level in the 6B heater due to mercury switch failure caused by corrosion due to direct steam/water impingement on the housing and coating of the switch actuating magnets with metal/paint covered filings which degraded the magnetic operating characteristics of the unit. The failed switch is located in a heater bay which history has shown having several leaks occurring in the vicinity of the level column resulting in direct impingement on the switch. The plant immediately reduced power and was forced into a premature entry into a refueling outage.
981028	OE9562	A number of problems have been identified with system 35 (Feedwater Heater Vents and Drain) LCV's. The problems encountered have been numerous broken air lines, 6th point heater LCV's having broken yokes, broken welds on the internal bushing in Feedwater Heater 33E-4B LCV, and positioners not controlling due to vibration damage.

Table E-1 (cont.)
Operating Events

Date	Event (See Para E.2)	Event Description
981102	36274	Power hold due to FW heater level instabilities.
981105	36275	The turbine was taken off-line to realign the FW system due to FW heater level instabilities.
981109	17095	While shutting down for a refueling outage, a reactor trip from 22% power occurred due to a turbine trip. It was concluded that a high-high level trip from one of the low pressure FW heaters was the most likely cause of the turbine trip. (LER# 9805)
981115	OE9711	During a tagging out of equipment for maintenance, an unexpected isolation of the moisture separator normal level control valve started due to an error in the P&ID. Operators recognized the condition and corrected the problem immediately, but one of the MSRs reached the high level trip setpoint resulting in a turbine trip. This high level trip condition occurred because the dump valve did not open. Cause was determined to be high friction between the seat and plug caused by rough edges on both the seat and plug. The rough edges are most likely caused by steam cutting due to identify seat leakage. The valve has design leakage (ANSI class 3) and steam cutting will occur since the downstream side is at condenser vacuum. Another cause was Dirt or foreign material (e.g., iron carryover) may have existed between the seat and the plug. The dirt would have been flushed away during the cold stroking of the valve.
981229	OE9663	Feedwater heater level transmitters were being calibrated. An expected high level alarm was received in the control room for feedwater heater 4B. However, several unexpected secondary plant alarms were also received. It was assumed that most feedwater heaters have the capability to have level control switched to alternate level transmitters, but feedwater heater 4B did not. In the initial planning, it was recognized that feedwater heater 4B could not be calibrated at power, but this was not documented or communicated to personnel performing the work.
990105	31306	Load reduction due to lost heater drain forward flow, which was caused by heater drain tank level controller card setpoint drift.
990218	15313	Load reduction due to FW heater E1A controller failure.
990324	15315	Load reduction to replace FW heater level controller.
990422	3772	While at 100% power, failure of a digital FW control system (DFCS) power supply caused one FW regulating valve to close and the other to lock-up in its pre-existing position. Attempts to manually control reactor water level failed due to the DFCS failure, resulting in an automatic reactor low water level scram. Subsequently, steam lines for the main steam system, HPCI, and RCIC were overfilled, causing HPCI and RCIC to become inoperable for about 30 minutes. The DFCS power supply failure was due to an oxidized connection in a +5 volt power supply. The overfill was caused by the failed level indications and misleading Safety Parameter Display System indications. (LER# 9904)

Table E-1 (cont.)
Operating Events

Date	Event (See Para E.2)	Event Description
990517	OE10139	31 Heater Drain Pump (HDP) automatically shutdown due to a low flow condition in the discharge line. The cause of the low flow condition was the failure of a positioner on 36B Feedwater Heater Level Control Valve. The failed positioner reduced the level in the Heater Drain Tank (HDT) which reduced the flow in the HDT outlet by throttling closed the HDT Level control Valve. The positioner characterizing cam and interfacing roller had worn. A contributing cause was the frequent level oscillations in 36B Feedwater Heater that made the feedback arm rotate the cam against the roller.
990529	19951	Manual reactor trip from 100% due to a steam leak in the Turbine Building caused by a FW heater level control system malfunction. (LER# 9909)
990609	11528	The unit was operating at 66% power when the reactor tripped on an anticipatory trip following a main turbine trip. The trip was due to a spurious trip signal caused by two concurrent electrical ground faults in the MSR high level switches. The root cause of one ground was a manufacturing deficiency that allowed a wire to chafe against a sharp edge. The second ground was due to missing adhesive that allowed a Mercury switch vial to move in its retaining bracket until a conductor contacted the metal bracket. The investigation determined the adhesive might have degraded over time. (LER# 9902)
990617	12921	Load reduction for FW heater 15B controller relay repair.
990709	OE10347	While at full power, a secondary plant transient resulted in a Heater Drain Pump Low Flow alarm on the Plant Monitoring System computer. This was followed by Third Point Heater Drain Tank High Level Alarm and Third Point Feedwater Heater High Level Alarm. The high level dump valves for both the feedwater heater and the drain tank opened. The Feedwater Heater Extraction Valve went closed and the Condenser Vacuum Pretrip Alarm was received. Further investigation showed that Heater Drain Pump was on minimum flow even though discharge valve indicated full open. It was concluded that the most probable cause was separation of the plug and stem in this valve. The groove pin holding the threaded stem in place in the plug was broken, and the stem had backed out of the plug. The root cause was discussed in OE11250.
990722	OE10485	While operating at full power the plant experienced a high level condition on the Low Pressure Feedwater Heater 3C. The Feedwater string automatically isolated and shortly thereafter, a power reduction was initiated as a result of the reduction in feedwater heating. The cause was a severed instrument air line on the air supply to the level control valve for the 3C Feedwater Heater. Metallurgical analysis of the broken line found that the primary mode of failure was high cycle fatigue. The fatigue and ultimate failure of the line was due to the high vibration at the valve.
990913	5654	An unplanned scram was manually initiated while at 27% power because of degrading vacuum in the main condenser. The root cause of the event was the failure of the augmented offgas (AOG) system train B condenser level control system in conjunction with AOG air purge flow that overcame the capacity of the main condenser air ejector system. (LER# 9909)

Table E-1 (cont.)
Operating Events

Date	Event (See Para E.2)	Event Description
990917	OE10772	During a reactor startup, high water level alarm was received for the main steam moisture separator 2C2 level control reservoir. The high level controller for the 2C2 moisture separator reservoir was observed to be indicating downscale and the normal level controller was indicating full scale. The other moisture separator reservoirs were at various levels as indicated by the normal and high controllers. The moisture separators drain pump suction valves were opened, and but water level did not reduce the 2C2 level. Initial diagnosis was instrument reference leg problem. About 1½ hours after the initial alarm, a main turbine trip occurred on moisture separator 2C2 high level. Reactor power was 30 percent at the time. The root cause of the failure was a malfunction of the level transmitter for the high level controller for the 2C2 moisture separator level control reservoir.
990929	44741	Load reduction to 98% due to a FW heater string B isolation.
991006	40652	Runback due to 3B, 4B, and 5B FW heater trip caused by a fuse problem.
991109	OE 11452	The 2D1 Feedwater Heater (FW) Emergency Drain Valve opened on high level in the heater. The 2D1 Normal Drain Valve was receiving a full open signal but was actually only 1/2 open. Two of the four bolts which fasten the actuator casing to the valve yoke were broken. This caused the valve actuator to bind preventing the valve from going full open. The bolting was found to have failed due to High Cycle Fatigue. The valve has been installed in this system since 1970 and still contained original actuator parts.
991110	OE10609	Following a power reduction to 50% due to "B" Reactor Feed Pump speed control problems, Feedwater level control problems were experienced in the “A” Feedwater heater string. High level problems began in the 3A Feedwater heater. Due to sluggish valve operation in the remaining feed heaters in the “A” Feedwater heater string, high and high-high levels were experienced in the 4A, 5A, and 6A heaters. Power was further reduced and operators took manual control of Feedwater heater levels to stabilize the levels. Investigation found that 3A Feedwater Heater level control valve (LCV) failed. The valve was jammed in the intermediate stroke position (loss of control) due to movement of lower guide bushing causing seat/disc interference. The valve was service for 24 years.
991202	27476	With the unit operating at 98% power, the reactor was manually tripped due to the loss of two of three FW pumps. The FW pumps tripped on low suction pressure due to the loss of discharge flow from the A high pressure heater drain pump following a secondary plant transient. The AFW pumps automatically actuated following the reactor trip to restore inventory in the SGs. The cause of the event was the failure of a FW heater level control switch to properly actuate. (LER# 9904)

Table E-1 (cont.)
Operating Events

Date	Event (See Para E.2)	Event Description
991208	OE11061	When placing FWH 25C on its high-level dump valve (by isolating normal control) in preparation for hanging an equipment clearance, the level increase was too rapid to allow high level dump valve to mitigate the level increase and allowed a high level trip of FWH 25C. Over the next several minute consequential isolations occurred along with drain pump trips. Power was reduced and plant was stabilized at 40% power with the DA tank recovering level. It was determined that evaluations of recent events where cascading FWH trips had occurred during plant shutdown had been superficial and had incorrectly concluded that this was a normal plant response, despite the absence of similar instances in other unit or earlier in this unit 2's operating history. Numerous level control valves involved were found to be subject to sticking and this fact had not been otherwise factored into the preventative maintenance program.
000105	14572	With the plant operating at 100% power, an automatic scram occurred when technicians attempted to restore a level transmitter to service after calibration. The scram signal resulted from a false low level signal generated due to an inadequate instrument restoration process. (LER# 2000-01)
000106	22222	A manual reactor trip from 100% power was initiated due to a loss of FW pump #12 and degraded FW pump suction pressure as a result of the isolation of condensate flow to the FW pumps. The loss of condensate flow was attributed to radio frequency interference (RFI). Based on the troubleshooting performed, the FW heater level instrumentation was determined to be susceptible to RFI. Use of radios within the vicinity of the FW heater level instrumentation would cause the FW heater isolation valves (CN27's) to close. (LER# 2000-01)
000115	OE12189	During turbine control valve testing, the plant received a high level alarm on the third point “A” heater. Investigation of the alarm found the normal heater level control valve indicating “full open” and the heater level was being controlled on the high-level dump valve to the condenser. It was later confirmed that the normal heater level control valve had experienced stem-disc separation and preparations were made to repair the valve.
000127	17862	With the unit at 100% power, a manual reactor trip was initiated due to a rapid decrease in the B SG level to 57% and the trip of a FW pump. This event was caused by the loss of all heater drain flow to the suction of the FW pumps as a result of bulk flashing in the heater drain tank. The transient was initiated due to the restoration of the 2A FW heater's sightglass causing oscillations in the FW control system that adversely affected the system's ability to recover from the transient. Also, the heater drain tank vent control valve, 2-HD-104, control logic wiring did not permit the valve to function properly in order to mitigate the consequences of a loss or rapid reduction of extraction steam pressure on the heater drain tank.

Table E-1 (cont.)
Operating Events

Date	Event (See Para E.2)	Event Description
000325	12388	Load reduction to 66% due to FW heater 4C level control problems.
000428	OE11068	During shutdown, the unit tripped from 22% power due to a turbine trip. The turbine trip was caused by a Hi-Hi level signal from a FWH. It was determined that the cause of the signal was due to the piping and valving geometry associated with the level instrumentation for the heater, that allowed a momentary Hi-Hi level signal to be generated due to flashing in the lower sensing line of the Hi-Hi level switch. In this event, the signal was activated for only 0.8 seconds. A T- style globe valve in the instrumentation piping was installed with the stem down. The pocket thus formed provided sufficient volume that flashing of water provided enough steam to lift float and give high level signal. Valve has been replaced with a gate valve and its orientation in the line adjusted. The piping has been checked for proper slope and adjusted.
000524	22888	The unit was operating at 100% power when an invalid low reactor water level scram signal was generated while returning a FW level transmitter to service following scheduled calibration. The root cause of this event was determined to be lack of specific proceduralized valving sequences for this level transmitter based on the current design and procedural guidance. The scram was the result of a pressure perturbation in the common variable sensing line shared with both channels of RPS level transmitters. (LER# 2000-05)
000529	16556	Power hold at 86% to repair a heater drain level instrument leak.
000805	OE12500	While the plant was at 100% power, moisture separator drain tank (MSDT) level reached approximately 30% and dropping. The MSDT high level dump valve was observed to be slightly opened and was isolated. Plant power was reduced to 91% to stabilize main feedwater pump suction pressure. MSDT level started to rise and was stabilized using the manual isolation valve. Upon further investigation the moisture separator drain tank normal level control valve, CV-0608, was found to be not responding to changes in level and was isolated and bypassed for troubleshooting. On August 6, 2000 a separate failure occurred when a similar valve, CV-0609, went from 50% open to 40% open and ceased responding to the level controller. This caused MSDT level to increase to 90%. Operations stabilized the level by isolating this valve and controlled level using the manual bypass. Troubleshooting found the CV-0608 actuator rod disengaged from its turnbuckle due to inadequate torque. The nut of the pivot bolt backed out and the CV-0609 actuator piston rod extension disengaged from the piston due to failure to implement vendor correction.
000807	16115	While at 100% power, the reactor experienced an automatic scram due to an invalid low reactor water level signal sensed by the RPS. The cause of the invalid level signal was the failure of the packing gland follower on variable leg root valve RRV 3-2-654B which resulted in the depressurization of the variable leg to various instruments. A PCIS Group 2 and Group 3 isolation signal, and secondary containment isolation also resulted. (LER# 2000-01)

Table E-1 (cont.)
Operating Events

Date	Event (See Para E.2)	Event Description
000929	19967	Load reduction to 80% due to heater drain level control problems.
001009	31364	Power was limited to 94% while FW heater 14A was operated on emergency drain until repairs were completed.
001009	31363	Load reduction to 70% due to FW heater isolation.
001124	17907	Load reduction for condenser hotwell A level transmitter replacement.
010125	OE12312	During a planned evolution to isolate a FWH normal level control valve (CV-0605), MSDT normal level control valve (CV-0608) failed in the 30% open position. The MSDT level rose to 80%, which forced the MSDT high level dump valve (CV-0609) to open, resulting in lowering Main Feedwater (MFW) Pump suction pressure. Restoration of MFW Pump suction pressure to normal while flow was diverted back to the Main Condenser required a derate to 90% power. The Apparent Cause for the failure of CV-0608 in the 30% open position is the failure of the positioner POC-0608. Contributing to the failure of the positioner was the environment this valve exists in and the fact that its “soft goods” (elastomeric parts, e.g., air regulator filter) have not been routinely replaced.
010503	OE12861	A feedwater heater drain level control valve was cycling open and closed causing level swings in the 4B Feedwater Heater. Trouble shooting determined that the rotary shaft arm of the positioner for the valve was found badly worn and in need of replacement. The travel pin was found sheared off at its base. Inspection of the “A” train valve found a similar condition with a groove worn into the rotary shaft arm. Cause was determined to be defective part. Part was received without a nitrided (hardened) surface and wear occurred due to vibration.
010611	OE12641	A small Feedwater transient occurred at the when a Feedwater Heater Deaerator tank level transmitter failed and showed a high level deaerator tank signal. This caused the heater drain pump discharge valves to fully open which lowered level in the drain tank. The low level in the tank tripped the heater drain pumps. Cause was fracture of transmitter displacer stem thread thought to be due to fatigue. Cause of fatigue not known, but stem may have been bent so that up and down movement would have resulted in cyclic bending.
011221	OE13910	During turbine valve testing, a FWH tripped high-high level. An additional four more heaters received high-high level trip over the following 23 minutes later. The root cause of this event was due to the #1 and #2 feedwater heater throttleable condensate motor operated bypass valve not being fully closed. When shutting the motor operated valve, the operator did not continue to close the valve for 10 seconds after the closed indication was received as stated in the procedure. This resulted in the valve being 10% open.

Table E-1 (cont.)
Operating Events

Date	Event (See Para E.2)	Event Description
020204	OE14189	Also 020205 The 5B and 1B feedwater heaters (FWH) tripped on what appeared to be a spurious high-level trip. At the time of the trips, no other significant conditions or operations were in progress. The direct cause was a failure (open coil) of the miniature relays on the alarm cards. A lack of preventive maintenance on the electronic circuit cards for the Feedwater Heater Controls System was identified as the root cause of the event.
020622	OE14384	Due to a control failure, a condensate pump tripped. The pump trip resulted in a designed runback of the reactor recirculation pumps The 'A' moisture separator level control and dump valves did not control the expected rise in moisture separator level with the lowering reactor power. This ultimately caused a turbine trip and reactor scram. The moisture separator high level dump valves had exhibited slow response before. Adjustments were made to provide adequate response, but replacement of valve with faster opening design is thought to be the best solution. 67 events

F
SUMMARY OF KEY POINTS

The following list provides the location of key “pop out” information in this report.

Key O&M Cost Point

Emphasizes information that will result in reduced purchase, operating, or maintenance costs.

Referenced Section	Page Number	Key Point
7.3.1	7-2	Proper level is where the TTD and DCA are at their design values and sufficient level margin exists to prevent steam from entering the DCZ or water entering the turbine.
7.4.1	7-6	Due to process gain nonlinearities and heater internal flow dynamics, tuning will be effective and provide reliable level control at normal operating conditions only when it is performed at normal operating conditions, i.e., 100% power.

Key Technical Point

Targets information that will lead to improved equipment reliability.

Referenced Section	Page Number	Key Point
3.2.2	3-3	Tuning is optimal only for the value of the process variable that the tuning was performed at, or for the load that causes the process variable to vary.
3.3.2	3-5	The reason for integral action is to correct only one problem: offset.
3.5	3-10	Processes are either self-regulating or non-self-regulating.
3.5.2	3-11	Feedwater heater drain level is a non-self-regulating process.

Referenced Section	Page Number	Key Point
3.6.1	3-12	A non-self-regulating process has its own integral controller built in. As a result, controller integral action tuning is different from a self-regulating process.
3.6.2	3-14	Using the classical Ziegler-Nichols tuning values will not be effective for a non-self-regulating process such as level control—instability will likely occur.
6.2.2	6-2	Saturated conditions result in an environment that is unstable and is very sensitive to pressure variations and, to a lesser extent, to temperature changes. This can lead to flashing, cavitation, and other problems.
6.2.4	6-4	The density of condensate is very sensitive to the effects of flashing. If only 0.62% of the condensate flashes at a pressure of 60 psia (414.7 kPa), the overall density of the condensate is reduced 73%.
6.2.5	6-4	Cavitation is the reverse of flashing; therefore, cavitation damage is limited only to those areas susceptible to flashing.
6.2.6	6-5	The surface of a saturated fluid will fluctuate rapidly, and this fluctuation results in level sensor noise. This condition exists throughout the feedwater heater and, in particular, the level column. Tuning that responds to this noise may result in premature failure of the final control element due to wear.
6.3.2	6-9	The most important consideration for FWH level control limits is turbine water induction. The potential damage to the turbine can result in long forced outages.
6.5.7	6-13	For the narrow ranges of level changes involved in horizontal feedwater heater level control, tank geometry has little effect on level control linearity.
6.5.8	6-14	The surface of a saturated fluid will fluctuate rapidly, and this fluctuation results in level sensor noise. This condition exists throughout the feedwater heater and, in particular, the level column. Tuning that responds to this noise may result in premature failure of the final control element due to wear.
7.3.1	7-3	Manufacturer's markings are design values and do not take into account all of the effects of internal flow and condensing that occur during feedwater heater operation.
7.3.2	7-4	When testing feedwater heaters for optimal level, the top heater (highest pressure heater) should be tested first, followed, in order, by all lower pressure heaters, to avoid interactions due to cascading drains.
7.5.1	7-8	Both the normal and the alternate drain must be sized for a minimum of FULL condensed extraction flow and ALL cascaded drain flows.

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