Westinghouse Technology Advanced Manual

Chapter 4

TECHNICAL ISSUES

Section

Westinghouse Technology Advanced Manual

Section 4.1

10CFR50.46 Bases

TABLE OF CONTENTS

4.1 10CFR50.46 BASES

Learning Objectives:

1. State the five acceptance criteria for emergency core cooling systems as presented in 10CFR50.46.
2. Explain the basis for each criterion covered in 10CFR50.46.

4.1.1 Background

Interim criteria for the design of emergency core cooling systems (ECCSs) were published in 1971 and submitted to the various vendors and owner groups. These criteria applied for a set grace period, to allow the vendors a reasonable amount of time to compile data for the public hearings prior to the establishment of the final ECCS acceptance criteria. The final criteria were to provide reasonable assurance that the ECCSs would be effective in limiting core damage in the highly unlikely event of a loss of coolant accident (LOCA).

The initial conditions used in the loss of coolant accident description are as follows:

1. 102% Reactor Power

   Operating at this power level for an indefinite period accounts for the available stored heat. Even though such operation is unlikely, this power level is used to include margins for instrument error.

2. 600°F Cladding Temperature

   At the initiation of the LOCA, the cladding would be at a temperature near that of the adjacent coolant, or approximately 600°F.

3. 2000°F UO_2 average temperature, and 4000°F peak centerline temperature.

   The average and peak centerline temperatures are selected as calculated temperatures at the onset of the LOCA. It is realized that the hottest fuel pellets (hot spots) will be well above both of these figures.

The excess heat contained in the fuel pellets is called stored heat and is approximately proportional to the power density and the thermal resistance of the gap. Stored heat is an important factor because it will significantly contribute to the cladding temperatures during the LOCA scenario.

After all the documentation was submitted and testimonies heard, the AEC made its decisions, and the final acceptance criteria were published in December 1973. Some of these criteria were highly contested by the vendors and utility groups. Their arguments and the bases for these criteria are discussed in section 4.1.3.

4.1.2 ECCS Acceptance Criteria

During a large LOCA some cladding damage will occur; however, this cladding damage must be limited to ensure that the health and safety of the public is protected. The amount of damage experienced depends on the initial heat generation of the core and the post-LOCA heat removal by the ECCSs. A set of emergency core cooling system performance acceptance criteria has been developed by the Nuclear Regulatory Commission; they are listed below:

1. The peak cladding temperature shall not exceed 2200°F.
2. Only 17% of the cladding thickness shall oxidize.
3. Hydrogen generation shall be limited to one percent of the value that would be generated if all of the core's cladding underwent a zirconium/water reaction.
4. The core shall remain in a coolable geometry.
5. Long-term core cooling must be maintained in order to remove core decay heat.

The cold-leg break in a pressurized water reactor is the worst-case break due to the tortuous flowpath for the steam that must exit the reactor vessel. This flowpath would be from the vessel, through the hot leg, through the tubes in the steam generator, through the impeller of the reactor coolant pump, through a portion of the cold leg, and then out the break. As steam accumulates in the reactor vessel, its pressure increases and retards the core reflood rate, thereby allowing the hot spots in the core to increase to attain even higher temperatures.

4.1.3 Bases

The bases for the limits established in 10CFR50.46 are discussed in the following paragraphs.

4.1.3.1 Peak Cladding Temperature and Oxidation

To maintain the integrity of the fuel rods the ductility of the cladding must be maintained. There are two physical changes that will affect the ductility of the cladding; one is metallurgical (crystal phase change), and the other is chemical (oxidation).

Zirconium has two different crystal structures, of which one is the alpha phase, and the other the beta phase. At room temperature zirconium is in the alpha phase, which is a brittle crystal structure.

When this metal is heated above 1150°F, the crystal structure is transformed into the beta phase, which is ductile. However, if the zirconium cladding oxidizes, even though its temperature is above 1150°F, the crystal structure of the zirconium dioxide is the brittle alpha phase.

Oxidation of the cladding is a chemical event that is normally referred to as a metal/water reaction. At high temperatures, water molecules are absorbed at the surface of the cladding and dissociate into hydrogen and hydroxyl radicals. Within the cladding the hydroxyl radicals, after several chemical steps, are converted into oxygen ions and hydrogen atoms. The hydrogen atoms, wherever formed, will combine into hydrogen molecules and escape from the surface of the cladding. The oxygen ions, however, diffuse further into the cladding and are dissolved in the metal. As this reaction continues, and if the concentration of oxygen is high enough, zirconium dioxide is formed. This oxidation process takes place between 1400 and 1700K (2060 and 2960°F, respectively), and even though the value is in dispute, somewhere between 2400 and 2600°F the oxidation process becomes more pronounced. Where zirconium dioxide is formed the cladding becomes brittle, and the loss of ductility of this metal may cause the fuel rods to burst upon quenching.. The thickness and the rate of oxidation is temperature dependent.

4.1.3.2 Hydrogen Generation

This criterion ensures that hydrogen would not be generated in amounts that could lead to explosive concentrations. This criterion is the same as the interim acceptance criterion, with the exception that it is more explicit in detailing how much of the zircaloy is to be in the one percent hydrogen calculation.

4.1.3.3 Coolable Geometry

Calculated changes in core geometry shall be such that the core remains amenable to cooling.

4.1.3.4 Long-Term Cooling

After any calculated initial operation of the ECCSs, the calculated core temperature shall be maintained at an acceptably low value, and the decay heat shall be removed for an extended period of time.

The long-term maintenance of cooling is considered from the time the cladding is cooled to 300°F or less, and the intent of this criterion is self-evident.

4.1.4 10CFR50 Appendix K

10CFR50 Appendix K provides the guidelines for the ECCS evaluation models. Some of the highlights of this appendix are listed below:

1. The appendix provides the parameters and initial assumed values that shall be used in the ECCS design calculations. When the computer runs are made to evaluate the effectiveness of the ECCSs and the maximum temperatures reached in the core, they must involve conservative assumptions as to the amount of stored heat, power history, decay of fission products, etc.

2. The appendix specifies the single failure criterion for the ECCSs. The ECCS evaluations must assume the most damaging single failure of the ECCS equipment.

Westinghouse Technology Advanced Manual

Section 4.2

Intersystem LOCA

TABLE OF CONTENTS

LIST OF FIGURES

4.2 INTERSYSTEM LOCA

Learning Objectives:

1. Define and explain the significance of an intersystem loss of coolant accident (LOCA).
2. Explain the changes made to reduce the risk of an intersystem LOCA.

4.2.1 Introduction

Several systems connected to the reactor coolant pressure boundary have design pressures considerably less than the reactor coolant system (RCS) operating pressure. The Reactor Safety Study (WASH-1400) identified the intersystem loss of coolant accident in a pressurized water reactor as a significant contributor to the risk of core damage.

The particular intersystem LOCA identified in WASH-1400 involved the failure of two check valves in the injection lines of the low pressure safety injection system, which would allow the high pressure reactor coolant to pressurize the low pressure safety injection piping located outside the containment. The resultant rupture of this low pressure piping would cause a loss of coolant outside the containment. As a result, no inventory in the containment sump would be available for recirculation; this plant state would lead to a subsequent core meltdown.

The probability of failure was evaluated for various valve configurations which include check valves and motor-operated valves. The five-year failure rate of the check valves was calculated to be somewhat large (4×10^{-6} per reactor year) with an estimated error factor of ten.

4.2.2 Description

4.2.2.1 Intersystem LOCA Scenarios

The systems of most concern are the low pressure safety injection systems that are connected to the reactor coolant system pressure boundary. Figure 4.2-1 illustrates a Westinghouse four-loop design low pressure safety injection system, wherein the residual heat removal (RHR) pumps take a suction from the refueling water storage tank (RWST) and inject into each of the four cold legs of the RCS.

The piping from the RCS to the motor-operated isolation valves located outside the containment is designed for full system pressure (2500 psia). The discharge piping of the low pressure injection (RHR) pumps is rated at 600 psig, which is based on the allowable suction pressure for decay heat removal operation plus the differential pressure developed by the pumps. The accident of concern is a postulated LOCA in the auxiliary building, which could occur if the series check valves, labeled CV1 and CV2, leak, thereby overpressurizing and possibly causing the failure of the 600-psig RHR discharge piping. This is very conceivable because in most Westinghouse designed plants the valves labeled MV1 and MV2 are normally open.

In those units that operate with low pressure injection motor-operated valves MV1 and MV2 closed, the closed isolation valves minimize the possibility of an intersystem LOCA. However, technical specifications require that surveillances of safety-related systems be performed in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code. Section XI of the ASME code requires the timing of safety-related valves as they are stroked from their normal positions to their accident positions. The time for each valve to stroke must be less than or equal to the operating time assumed in the safety analysis report. The motor-operated isolation valves in the low pressure safety injection system must be tested quarterly in accordance with ASME Section XI. If leakage exists through both series check valves, possible overpressurization and rupture of the low pressure piping could occur during testing.

4.2.2.2 Operating Experiences

With two series check valves the probability that at least one of the check valves is seated and not leaking is extremely high. In addition, if leakage were to occur to the point of causing a LOCA in the low pressure piping, the high differential pressure across the check valves would cause them to seat, which would terminate the accident. However, both of these statements are weakened by reviewing actual operating experiences.

The Nuclear Power Experiences Manual shows that between 1974 and 1978 there were nine dilution events (of which six occurred at Westinghouse plants) in the cold leg accumulators. The dilution of the boric acid was due to leakage of reactor coolant through series check valves CV1 and CV3, as shown in Figure 4.2-1. In response to these events, a letter, dated February 23, 1980, was issued from the Office of Nuclear Reactor Regulation to all light water reactor licensees.

This letter in part reviewed the concerns of the predicted accident as stated in WASH-1400, and the letter advised the licensees to preform leakage tests as soon as possible. In addition, the plants were required to review the piping and valve configurations of the low pressure safety injection systems and to report any known failures or valves found to lack mechanical integrity.

4.2.2.3 Final Results

Plant technical specifications (RCS operational leakage) have been revised to limit the amount of leakage through any reactor coolant pressure isolation valve and to require increased surveillance testing of these valves in order to provide added assurances of valve integrity, thereby minimizing the possibility of an intersystem LOCA. If excessive leakage exists through any one of the check valves, the low pressure portion of the system piping must be isolated by at least two manual or deactivated automatic valves. However, operability of most units' emergency core cooling systems (ECCSs) cannot be maintained with injection paths isolated in this manner, which requires those units to shut down in accordance with the technical specification action statements for the ECCSs.

In order to comply with the leakage requirements for these check valves, methods for detection and measurement of any leakage must be provided. The section of piping between series check valves CV1 and CV2, as shown in Figure 4.2-2, assuming no leakage, should be at the same pressure as the cold-leg accumulators. If a pressure sensor is located at this point, any increase in the indicated pressure above the accumulator pressure would be indicative of a leak from the reactor coolant system into this portion of the system. In addition, a pressure sensor located on the pump side of the second series check valve should indicate the head of the refueling water storage tank. Therefore, any pressure increase sensed here would indicate leakage past the second of the two series check valves.

Some plants have installed pressure transmitters at the appropriate points in their low pressure injection systems (see Figure 4.2-2), with remote indication and/or alarms in the control room, to provide indications of leakage as decribed above. The amount of leakage through various check valves can be determined by opening test valve TV1, 2, 3, or 4 as appropriate, depressurizing the associated line, then reclosing the valve and measuring the time required for repressurization. Another method would be to depressurize the line by opening the appropriate test valve to depressurize the system, and then to open test valve TV5 to collect the leakage. This approach would provide the most accurate measurement of any suspected leakage.

Changes to technical specifications required additional testing of the pressure isolation valves. A typical surveillance that each valve be tested:

1. At least once per 18 months,
2. Each cold shutdown period in excess of 72 hours, if leakage testing has not been performed in the previous nine months,
3. Prior to returning the valve to service after preventative or corrective maintenance, and
4. Within 24 hours following valve actuation due to automatic or manual action or flow through the valve.

4.2.3 PRA Insights

The intersystem LOCA is of major concern because it involves the loss of coolant outside of the containment building. Therefore, the water will not be available for recirculation upon the emptying of the refueling water storage tank. With these conditions there is no method available for cooling of core, with core damage resulting soon after the emptying of the refueling water storage tank. Also, since the low pressure injection system is located in the auxiliary building, the radioactivity associated with the break can be released to the environment.

NUREG-1150 considered the intersystem LOCA and its effects on the core damage frequency. The intersystem LOCA is caused by the failure of series check valves in the low pressure injection system, allowing the high pressure from the reactor coolant system to pressurize and rupture the low pressure piping. The contribution of the intersystem LOCA to the total core damage frequency varies from about 3.6% for Surry to 0.4% for Sequoyah. One of the reasons that Sequoyah has a lower probability than Surry is that the operators may be able to isolate an intersystem LOCA at Sequoyah by shutting the low pressure injection valves.

4.2.4 Summary

The intersystem LOCA is a safety concern due to its relatively high probability. Recall that a LOCA outside of the containment would result in the inability to provide core cooling after the injection phase of the accident is over, which could then result in a core melt. In order to reduce the probability of this type of accident, licensees' technical specifications have been changed to limit the maximum leak rate past the valves of concern, and to increase surveillance of these components.

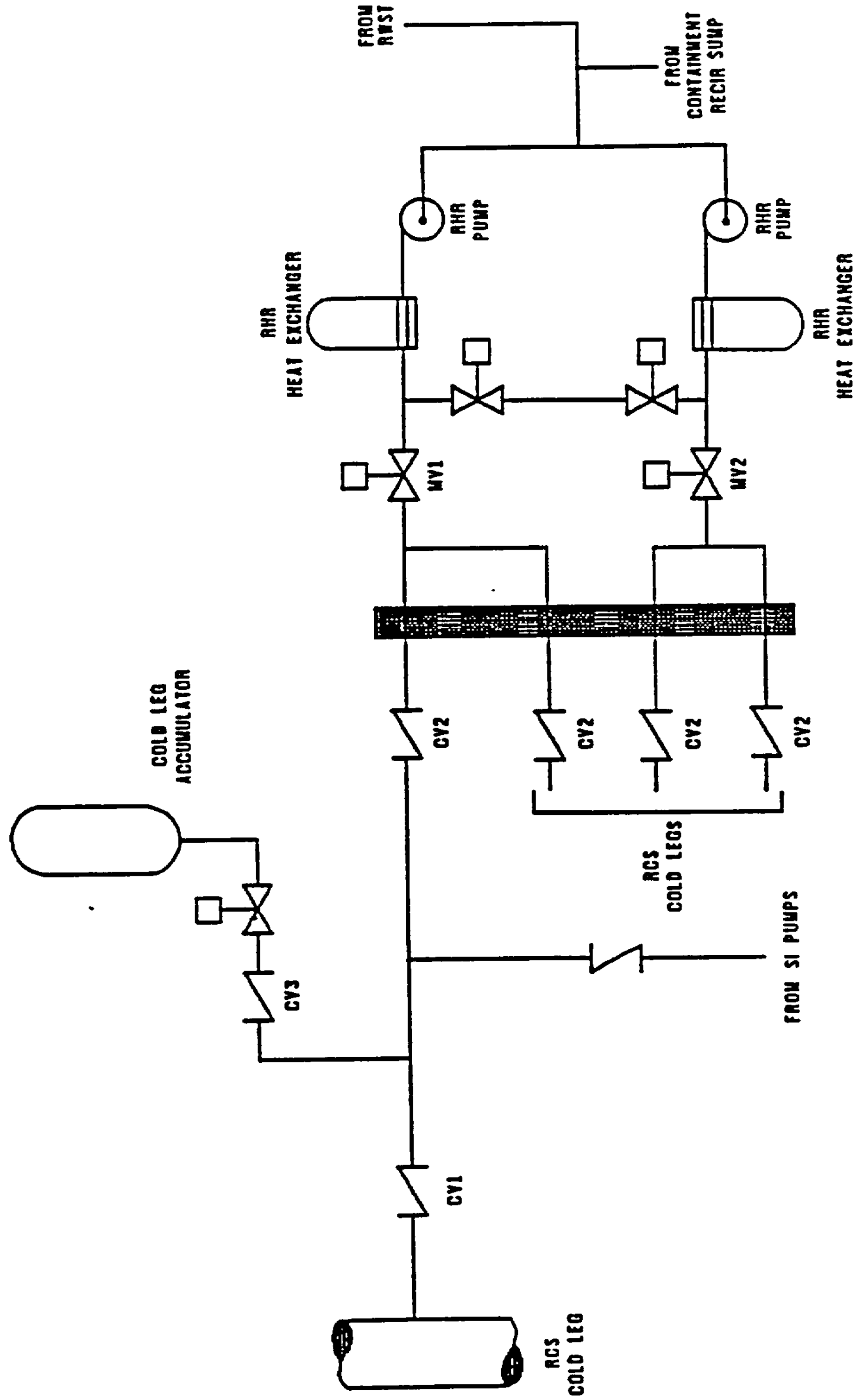


Figure 4.2-1 Low Pressure Safety Injection

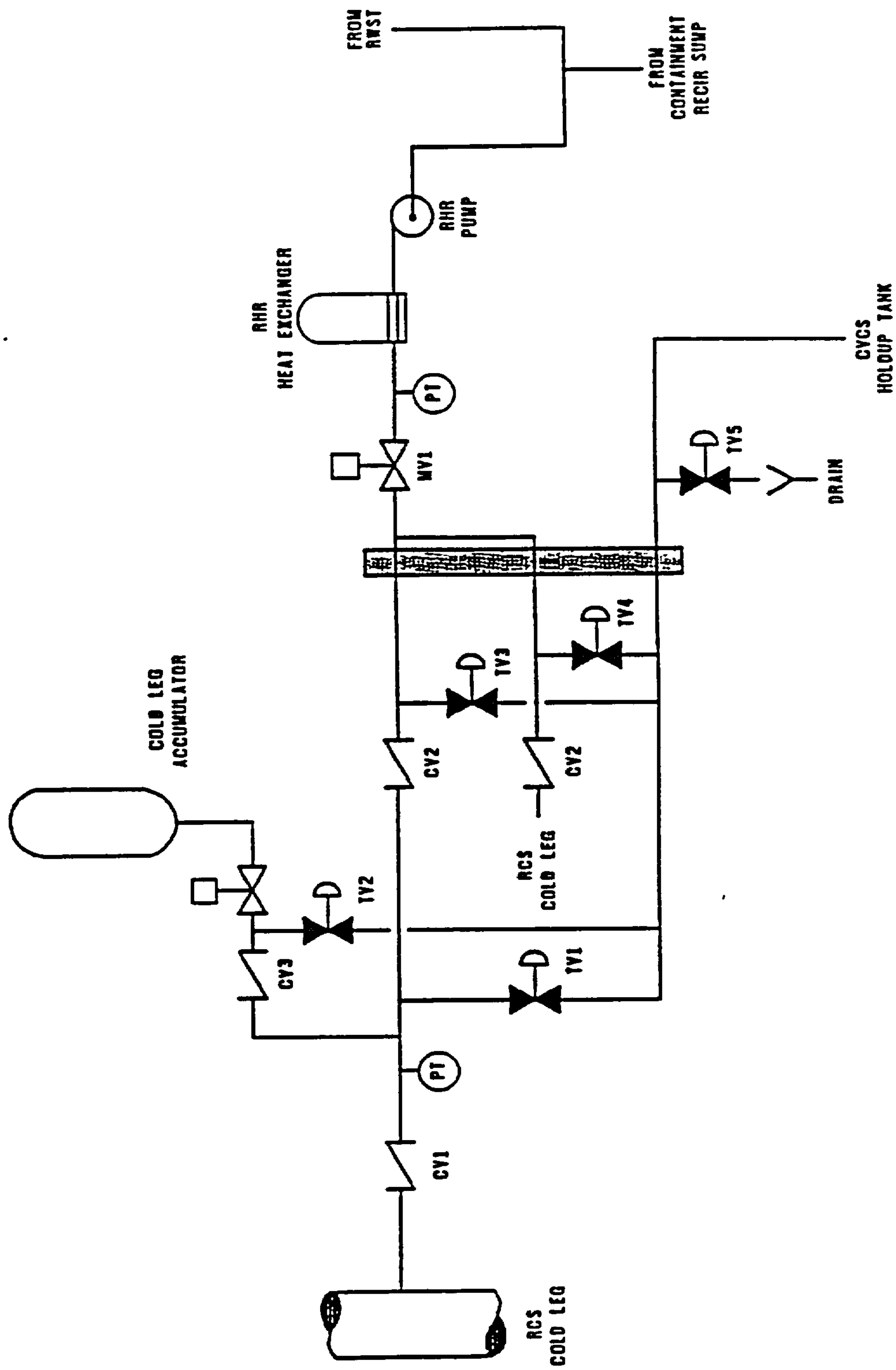


Figure 4.2-2 Low Pressure Safety Injection Test Valves

Westinghouse Technology Advanced Manual

Section 4.3

Reactor Coolant Pump Seal Problems

TABLE OF CONTENTS

LIST OF FIGURES

4.3 REACTOR COOLANT PUMP SEAL FAILURES

Learning Objectives:

1. Describe the operation of the Westinghouse reactor coolant pump (RCP) seal.
2. Describe indications of an RCP seal failure that are available to the operator.
3. Describe how the RCP seal is designed to permit pump operation with a failed number 1 seal.
4. Describe the possible results of not isolating number 1 seal return flow after the number 1 seal fails.

4.3.1 Introduction

For the a pressurized water reactor (PWR), the integrity of the reactor coolant pump seals is necessary for the operation of the large coolant pumps needed for heat removal from the reactor core, and at the same time essential to the integrity of the reactor coolant system (RCS) pressure boundary, by permitting essentially zero leakage from the RCS to the containment. The Westinghouse RCP seal package consists of three seals which must perform properly for continued pump operation. Seal failures can be minimized by proper installation, maintenance, and operation, but numerous occurrences of RCP seal failures have prompted close scrutiny by the NRC.

Commercial PWRs have RCPs made by several different manufacturers, including Westinghouse, Byron Jackson, Bingham, and KSP (a German firm). Each pump has a different seal design, but many similarities exist. This section presents a description of the Westinghouse RCP seal assembly in terms of its design and operation. The indications of a degraded RCP seal are discussed, as well as the operator response to a seal failure to minimize RCS inventory loss and to safely shut down the plant. Finally, brief descriptions of some of the reported incidents involving RCP seal failures are discussed to illustrate, among other things, how operator responses can significantly affect the consequences of seal failures.

4.3.2 Reactor Coolant Pump Description

The reactor coolant pumps provide sufficient forced circulation flow to ensure adequate heat transfer for power operation and adequate decay heat removal when the reactor is shutdown. Each reactor coolant pump is a vertical, single-stage, centrifugal pump designed to pump large volumes of reactor coolant at high temperatures and pressures. The pump (Figure 4.3-1) consists of three sections from bottom to top:

1. The hydraulic section, which consists of the inlet and outlet nozzles, casing, flange, impeller, diffuser, pump shaft, pump bearing, thermal barrier and thermal barrier heat exchanger.
2. The shaft seal section (shown in Figures 4.3-2 and 4.3-3), which consists of the number 1 controlled leakage seal and the numbers 2 and 3 rubbing face seals. These seals are located within the main flange and seal housing.
3. The motor section, which consists of a vertical, squirrel-cage, induction motor with an oil-lubricated double Kingsbury thrust bearing, two oil-lubricated radial bearings, and a flywheel with an anti-reverse rotation device, and appropriate support equipment.

4.3.2.1 Radial Bearing Assembly

The pump bearing is a self-aligning, spherical, graphitar-coated journal bearing. The bearing provides radial support and alignment for the pump shaft. It is water cooled and lubricated. It is essential that the water circulating through the bearing be kept cool. High temperatures can damage the graphitar coating and cause bearing failure. The cooling water is normally supplied as seal injection from the chemical and volume control system (CVCS).

4.3.2.2 Thermal Barrier Assembly

The thermal barrier assembly (shown in Figure 4.3-1) consists of the thermal barrier and thermal barrier heat exchanger. The thermal barrier is designed to limit the rate of heat transfer from the hot reactor coolant to the pump radial bearing and thermal barrier heat exchanger. It consists of a number of concentric stainless steel cylinders extending vertically from the top of the impeller to the thermal barrier flange, and a number of stacked horizontal plates at the flange. The barrier to heat transfer is provided by the gaps between the cylinders and plates. The thermal barrier heat exchanger is located at the bottom of the thermal barrier assembly below the pump radial bearing. The function of this heat exchanger is to cool any reactor coolant leaking up the shaft to protect the radial bearing and shaft seals.

Seal injection water is normally supplied to the reactor coolant pump from the CVCS (see Figure 4.3-2). This water is injected into the pump at a point between the radial bearing and the thermal barrier heat exchanger. (In later model pumps [Westinghouse model 93A-1 - see Figure 4.3-3], seal injection water is supplied between the number 1 seal and the radial bearing. This feature eliminates the need to provide number 1 seal bypass flow at low RCS pressures.) Of the eight gpm supplied to each RCP, three gpm flows upward through the radial bearing and pump seals and five gpm flows downward through the heat exchanger and into the RCS. This downward flow acts as a buffer to prevent the hot reactor coolant from entering the bearing and seal area.

The reactor coolant pump is designed to operate with either seal injection or thermal barrier heat exchanger cooling. However, it is desirable to maintain bearing and seal cooling with the purified and filtered seal injection water, rather than with the contaminated, unfiltered reactor coolant leaking up the shaft from the RCS. The thermal barrier heat exchanger acts as a backup in the event of a loss of seal injection flow. Without seal injection, approximately three gpm (the normal shaft seal leakage) flows from the RCS through the heat exchanger to the pump radial bearing and the seals. Labyrinth seals between the shaft and heat exchanger force most of this water through the heat exchanger. Operation of the reactor coolant pump under these conditions is permitted only for a short period of time because the unfiltered coolant flowing through the seal package could damage the seals. Component cooling water is the cooling medium for the thermal barrier heat exchanger.

4.3.2.3 Coupling/Spoolpiece

A spoolpiece connects the pump and motor shafts. The spoolpiece can be removed to make the shaft seals accessible for maintenance without removal of the motor.

4.3.2.4 Shaft Seal Section

The function of the shaft seal assembly is to provide essentially zero leakage from the RCS along the pump shaft to the containment atmosphere during normal operating conditions. The assembly consists of three seals, two of which are full design pressure seals and a third which is simply a leakage diversion seal. Figures 4.3-2 and 4.3-3 show the relative positions of the three seals. The seal assembly is located concentric to the pump shaft as it passes through the main flange. The seals are contained in a seal housing, which is bolted to the top side of the main flange.

Number 1 Seal

The number 1 seal is the main seal of the pump. It is a controlled-leakage, film-riding seal in which the sealing surfaces do not contact each other. Its primary components are a runner which rotates with the shaft and a non-rotating seal ring. The seal ring and runner are faced with aluminum oxide coatings. If the two surfaces come in contact during operation, the seal is damaged and excessive leakage results. The number 1 seal produces a 2200-psi pressure drop.

During normal operation, cool injection water, at a pressure greater than RCS pressure, enters the pump through a connection on the thermal barrier flange at a rate of about eight gpm (Figure 4.3-2). About five gpm of this injection water flows downward through the thermal barrier/heat exchanger and into the RCS. This downward flow of water prevents the primary coolant from entering the seal area of the pump. The remaining three gpm of the injected water passes through the pump radial bearing and number 1 seal. This seal is termed a "controlled-leakage" seal because the leakage through the seal is controlled to a design value, which is maintained by floating the seal ring so that the gap between the non-rotating seal ring and the rotating seal runner is always held to a constant value (Figure 4.3-4).

To understand the concept of why the gap between the seal ring and the runner stays constant, it is necessary to examine the hydrostatic forces on the seal ring by dividing them into "closing forces" (those forces tending to close the gap) and "opening forces" (those forces tending to open the gap). A constant closing force proportional to the pressure differential across the seal is imposed on the upper surface of the seal ring. This is shown in Figure 4.3-4 as a rectangle on the force balance curve.

At equilibrium conditions, an equal and opposite opening force acts on the bottom of the ring. The non-uniform shape of the opening force is due to the taper on the underside of the ring. The taper causes the rate of change of the pressure drop, and thus the associated force, to be different from those in the parallel section of the ring. If the gap closes, the seal ring moves downward, and the percentage reduction of flow area in the parallel section is greater than that in the tapered section. This causes the resistance to flow in the parallel section to increase more rapidly than it does in the tapered section. This, in turn, distorts the force diagram and results in a slight increase in the opening force. The increased opening force pushes the seal ring upward, causing the gap to widen until equilibrium conditions are again established. A similar discussion would show that if the gap increases, the opening force decreases. The closing force (being greater) would then push the seal ring down and close the gap. Again, the seal ring is restored to its equilibrium position.

If the pressure in the primary system is decreased, the shape of the force balance diagram does not change. However, the actual values of the forces decrease. If the pressure in the RCS continues to decrease, the weight of the seal ring becomes a large part of the closing force.

At pressure differentials below about 200 psid, the hydrostatic lifting forces are insufficient to float the seal ring, and contact between the seal ring and its runner may occur, causing damage to both rings. Therefore, to prevent damage to the number 1 seal, it is not permitted to operate the pump with the number 1 seal differential pressures less than 275 psid. The minimum required differential pressure of 275 psid should be obtained when the RCS pressure is 400 psig.

At lower RCS pressures, the flow rate through the seals is less than that required to cool the pump radial bearing. A penetration is provided to bypass some flow around the number 1 seal when the pressure in the RCS is less than 1500 psig (see Figure 4.3-2). This feature ensures adequate radial bearing cooling flow.

Numbers 2 and 3 Seals

The number 2 seal is a rubbing-face seal consisting of a graphitar-faced seal ring which rubs on an aluminum oxide coated stainless steel runner. During normal operation, the number 2 seal directs the leakage from the number 1 seal to the CVCS (see Figures 4.3-2 and 4.3-3).

The function of the number 2 seal is to act as a backup in case of number 1 seal failure. The number 2 seal has full operating pressure capability. If the number 1 seal fails, it passes water at greater flow rates. The increased flow is sensed by leakoff flow detectors which indicate and alarm in the control room. The operator should then shut the number 1 seal leakoff flow control valve. This action directs all number 1 seal leakage through the number 2 seal, placing it into service as the primary seal. The plant should then be shut down using normal procedures to replace the failed seal. Normal leakage through the number 2 seal (number 1 seal not failed) is three gph.

The number 3 seal is a rubbing-face seal similar to the number 2 seal, except that it is not designed for full RCS pressure. It is provided to divert the leakage from the number 2 seal to the reactor coolant drain tank (RCDT). The number 2 seal leakoff is directed to a standpipe, which maintains a backpressure sufficient to ensure flow through the number 3 seal for cooling purposes. The leakoff from the number 2 seal is piped from the top of the standpipe to the RCDT. High and low level alarms on the standpipe alert the operator to malfunctions of the numbers 2 and 3 seals. Number 3 seal leakoff is also routed to the RCDT. Normal leakage through the number 3 seal is 100 cc/hr.

The primary components of the number 3 seal are a 304 stainless steel rotating runner with a chrome-carbide coated rubbing face and a graphitar 114 stationary ring, which is fitted to a 304 stainless steel holding ring. The operation of the seal package provides a near zero leakage from the RCS at the reactor coolant pump shaft.

The number 3 seal in a model 93A-1 RCP is a face-rubbing seal with a double face, called a double dam (see Figures 4.3-3 and 4.3-5). The number 3 seal is located above the number 2 seal, and its backpressure forces the three-gph leakoff from the number 2 seal into the RCDT via the number 2 seal leakoff connection.

The double-dam design permits the injection of clean water (800 cc/hr) at a slightly elevated pressure between the dams. A portion of this flow (400 cc/hr) goes into the cavity between the numbers 2 and 3 seals and then out the number 2 seal leakoff connection. The remaining flow (400 cc/hr) is discharged as number 3 seal leakoff into the normal containment sump. The injected flow provides the number 3 seal with clean water for lubrication and prevents dissolved radioactive gasses in the fluid which passes through the number 2 seal from entering the containment atmosphere.

4.3.2.5 Instrumentation

Temperature detectors are provided to monitor the temperature of the seal water inlet to the pump bearing and the number 1 seal outlet temperature. These temperatures are indicated, and alarm conditions are annunciated, in the control room.

The differential pressure across the number 1 seal is also indicated and annunciated in the control room to ensure a minimum ΔP for pump operation. This ensures a sufficient gap between the number 1 seal ring and its associated runner. Each seal supply to each RCP contains a flow transmitter and flow indicator followed by a seal injection throttle valve; all are located outside containment.

The number 1 seal leakoff flow is monitored, recorded, and annunciated in the control room. A high leakoff flow indicates a failed number 1 seal and alerts the operator to close the number 1 seal leakoff valve to place the number 2 seal in service. A low flow is usually associated with a low RCS pressure and indicates that insufficient seal leakoff exists to ensure proper cooling of the pump bearing. The operator should then open the number 1 seal bypass valve (a common valve for all pumps) to increase the leakoff flow and to provide sufficient cooling.

4.3.2.6 Cooling Water

It is essential that cooling water be supplied to the motor bearing coolers and thermal barrier heat exchanger during pump operation. Although it is possible to operate the pump without damage with no cooling flow to the thermal barrier heat exchanger, operation under these conditions should be minimized. If seal injection were lost while thermal barrier cooling is not available, hot reactor coolant would leak up the shaft into the bearing and seal area and damage these components.

The component cooling water system supplies the reactor coolant pump heat exchangers. The piping to the thermal barrier heat exchanger is designed to withstand full system pressure in case of a leak in the heat exchanger. The remainder of the system is low pressure piping.

In the event of a leak from the RCS into the thermal barrier heat exchanger, a high flow is sensed in the component cooling return line. This condition initiates an alarm and automatically isolates the return line. Isolation of the return line stops the leak flow, and the high pressure piping of the component cooling water system becomes part of the RCS pressure boundary. Component cooling water to the reactor coolant pumps is automatically isolated only by a containment isolation phase B signal.

If component cooling water is unavailable, the reactor coolant pumps must be secured within approximately two minutes.

4.3.3 Seal Failures

The following are brief summaries of some of the more significant RCP seal failure events at operating PWRs.

4.3.3.1 Oconee Unit 2 (1/74)

Oconee Unit 2 (a Babcock and Wilcox plant) was at power when a leak was detected in the seal injection line to the 2B1 RCP. Isolation of the one seal injection line for repairs was not successful, so seal injection to all RCPs was secured. About six hours after the work commenced, the operators started to receive alarms on high seal inlet temperature, high seal leakoff flow, high quench tank pressure; and various other temperatures and flows associated with the 2B2 RCP. Unit load was reduced from about 22%, and the reactor was manually tripped because of the indications of a seal failure on the pump.. The unit was cooled down and depressurized to allow inspection and repair of the failed seal. Approximately 50,000 gal of reactor coolant leaked into the containment. The maximum leak rate was about 90 gpm. Apparently a mechanical failure of an upper seal component had caused higher than normal seal leakoff, which overloaded the pump seal heat exchanger (similar to the thermal barrier heat exchanger in a Westinghouse RCP). The flow of hot reactor coolant through the seal package caused distortion and further damage. The pump seal was replaced, and steps were taken to increase the heat removal capability of the seal heat exchangers to ensure that they would be able to handle higher heat loads in the future. Additional instrumentation was added to monitor leakage from the seals.

4.3.3.2 H. B. Robinson (5/1/75)

H. B. Robinson (a Westinghouse plant) experienced a failure of the number 1 seal in one of its model 93 RCPs while operating at 100% power. Indications of fluctuations in the number 1 seal leakoff flow had been present for about 20 minutes prior to definite indication of number 1 seal failure. The definite indication of a number 1 seal failure was the leakoff flow indication for that RCP reaching and remaining off-scale high (greater than five gpm). The number 1 seal return isolation valve was not shut immediately, and the high flow of hot reactor coolant through the thermal barrier heat exchanger caused flashing of the component cooling water and automatic isolation of cooling water to all RCP thermal barrier heat exchangers. The RCP was secured after reactor power was lowered below the P-8 permissive setpoint (the plant tripped during the power reduction), and the seal return isolation valve for the failed seal was eventually shut. The prolonged flow of hot reactor coolant through the pump's lower radial bearing evidently caused bearing damage because when the pump was subsequently restarted, severe damage to the pump and the other seals in that pump resulted. The additional damage to the pump's thermal barrier labyrinth, lower radial bearing, and numbers 2 and 3 seals resulted in an RCS leak of 450 gpm, versus the maximum of 200 gpm previously predicted by Westinghouse for a failed RCP seal. The total leakage from the RCS was 200,000 gal. The plant was eventually brought to cold shutdown, and the damaged seals, lower radial bearing, and thermal barrier assembly were replaced. No specific cause of the number 1 seal failure was identified. The Westinghouse RCP seal technical manual (as well as plant procedures) was revised to ensure that the number 1 seal return isolation valve is closed immediately and the pump is secured within 30 minutes after indication of a number 1 seal failure.

4.3.3.3 Indian Point Unit 2 (7/2/77)

Indian Point Unit 2 (a Westinghouse plant) experienced an RCP seal failure while at two percent power. Indications of decreasing pressurizer level and pressure prompted the operator to place a second charging pump in service. Control room alarms and indications (high leakoff flow) caused the operator to suspect a seal failure, so the RCP was tripped and the reactor shut down. Total RCS leakage was estimated to be 90,000 gal; the maximum leakage rate was 75 gpm. No specific cause for the failure was identified, but it was assumed that the number 1 seal lost its lubricating film, and the subsequent contact of the seal faces caused gross failure. The pump's rotating element, including the seal package, was replaced.

4.3.3.4 Salem Unit 1 (10/21/78)

Salem Unit 1 (a Westinghouse plant) was heating up in preparation for a reactor startup. The operator noted no seal flow to one of the RCP's and secured the pump. There were indications that flow from the operating charging pump had been lost, so he started another pump. At this time he noted off-scale high leakoff flow from the secured RCP. The alarm computer also indicated that the containment sump and RCS drain tank pumps had started, indicating leakage into the containment. The seal return isolation valve for the suspected pump was shut in accordance with procedure, and the remaining RCPs were secured due to the loss of RCS inventory. A plant cooldown and depressurization was initiated. Before the plant was in cold shutdown and depressurized, about 15,000 gal of reactor coolant was leaked to the containment. No specific cause of the seal failure was identified. The seal package was replaced, but additional problems with high leakoff flow were experienced during the subsequent heatup. It was suspected that debris from the initial seal failure was backflushed into the number 1 seal because the operators normally left the leakoff isolation valves open during low pressure operations. Plant procedures were changed to require a minimum seal differential pressure of 200 psid during low RCS pressure conditions and to keep the seal return and bypass isolation valves shut. A check valve was subsequently installed in the line.

4.3.3.5 ANO-1 (5/10/80)

Arkansas Nuclear One Unit 1 (a Babcock and Wilcox plant) experienced an RCP seal failure while at power. Increased RCS leakage was noted by operators monitoring the makeup tank level. RCP instrumentation confirmed a problem with one pump's seals. A load reduction was commenced, and the RCP was taken out of service. Seal leakoff flow increased significantly when the pump was stopped. Reactor building pressure and radiation levels also increased. Approximately 64,000 gal of makeup water were used to maintain the RCS inventory during the subsequent cooldown and depressurization for seal repairs. The maximum leakage rate was 200 to 300 gpm. An inspection revealed that the third-stage seal experienced gross damage. No specific cause could be identified, though it was suspected that the seal might have lost cooling due to a closed bleedoff valve or that the seal had not been installed properly. It was concluded that the upper seal failed first and that debris and distortion caused the subsequent damage to the first- and second-stage seals.

In all, hundreds of events involving RCP seal-related failures have been reported since 1967, and the NRC has concluded that seal failure is the leading cause of RCP outages and a significant contributor to the risk associated with small loss of coolant accidents.

4.3.4 Regulatory History

NRC studies based on the occurrences of RCP seal failures at operating PWRs have shown that they occur with a frequency of an order of magnitude greater than the small pipe break frequency used in WASH-1400, "Reactor Safety Study." Since the small-break loss of coolant accident (LOCA) is a significant contributor to core damage in WASH-1400, the NRC has concluded that the overall probability of core damage due to small breaks could be dominated by RCP seal failures. Generic Issue 23, "Reactor Coolant Pump Seal Failures," was established, and a task action plan was developed in 1983 to study the issue and to make recommendations if it became apparent that the original design requirements were inadequate.

The proposed resolution for Generic Issue 23 is still in progress, but studies indicate that the Westinghouse seal package is particularly vulnerable to failure due to several of its design features. The film riding design of the number 1 seal makes it susceptible to sticking open and allowing higher than normal leakoff flows, and the fact that it relies on a film of water to prevent contact of the seal faces makes it more vulnerable to failure if the film is lost. Rubber O-rings used in the seal packages are likely to degrade when subjected to hot reactor coolant, which means that the seal package could experience significantly increased leakage if cooling to the RCP seals is lost due to a malfunction or to a loss of all ac power.

NUREG/CR-5167, "Cost/Benefit Analysis for Generic Issue 23: Reactor Coolant Pump Seal Failure," issued in April 1991, identifies several modes of RCP leakage that may be in excess of those assumed in licensee coping analyses for implementing the requirements of 10CFR50.63, the station blackout rule. Generic Letter 91-07, "GI-23, 'Reactor Coolant Pump Seal Failures,' and Its Possible Effect on Station Blackout," provided this information to licensees and reminded licensees that higher seal leakage rates could affect licensee analyses and actions addressing the station blackout rule.

As reported in Information Notice 95-42 (IN-42), in March of 1995 the Commission voted against the adoption of a proposed rule that would have resolved Generic Issue 23. The Commission concluded that the proposed rule did not provide a sufficient gain in safety to justify its issuance. The Commission was also concerned about potential inaccuracies in the NRC's seal leakage evaluation model and that the wide range of plant-specific considerations regarding RCP seals would result in the spending of excessive resources by some licensees without commensurate safety benefits. IN-42 further noted that some licensees are addressing the issue through the Individual Plant Evaluation Program and accident management strategies. Further action regarding this issue is forthcoming.

4.3.5 PRA Insights

A reactor coolant pump seal failure can result in a small-break loss of coolant accident. For example, the seal failure at H. B. Robinson resulted in a leak rate of 450 gpm. For a small-break LOCA, the high pressure injection system must be operable to supply the reactor coolant system with injection water for cooling. The reason the lower pressure emergency core cooling systems are not of use for this accident is the slow depressurization of the primary.

NUREG-1150 evaluated several accident sequences which include a seal failure. Most of the sequences are initiated by either a loss of all ac power or a loss of component cooling water. With these losses, the high head injection system is not available to provide normal seal injection, and the component cooling water system is not available to cool the thermal barrier heat exchangers and the emergency core cooling system pumps. The reactor coolant pump seals fail due to the loss of cooling, and a small-break LOCA results.

The seal failure at H. B. Robinson could have led to core damage if the plant had subsequently lost all ac power, the high head injection system, or the component cooling water system. The accident sequences with a seal failure resulting in a loss of coolant accident represent a total of 35.4% of the core damage frequency for Sequoyah (primarily due to the loss of component cooling water), about 80% for Zion (primarily due to the loss of component cooling water), and about 26.3% for Surry (primarily due to the loss of all ac power).

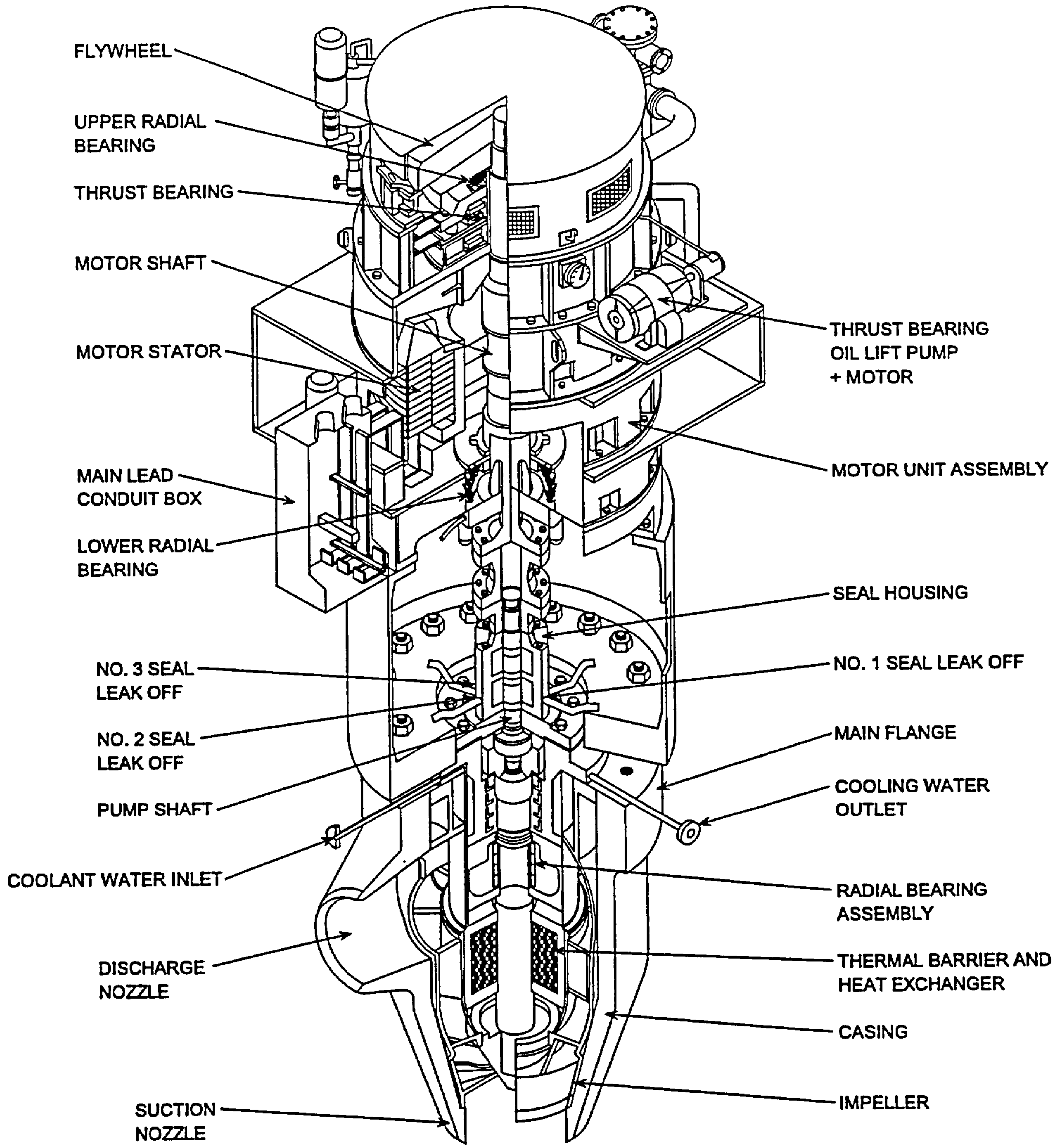


Figure 4.3-1 Reactor Coolant Pump

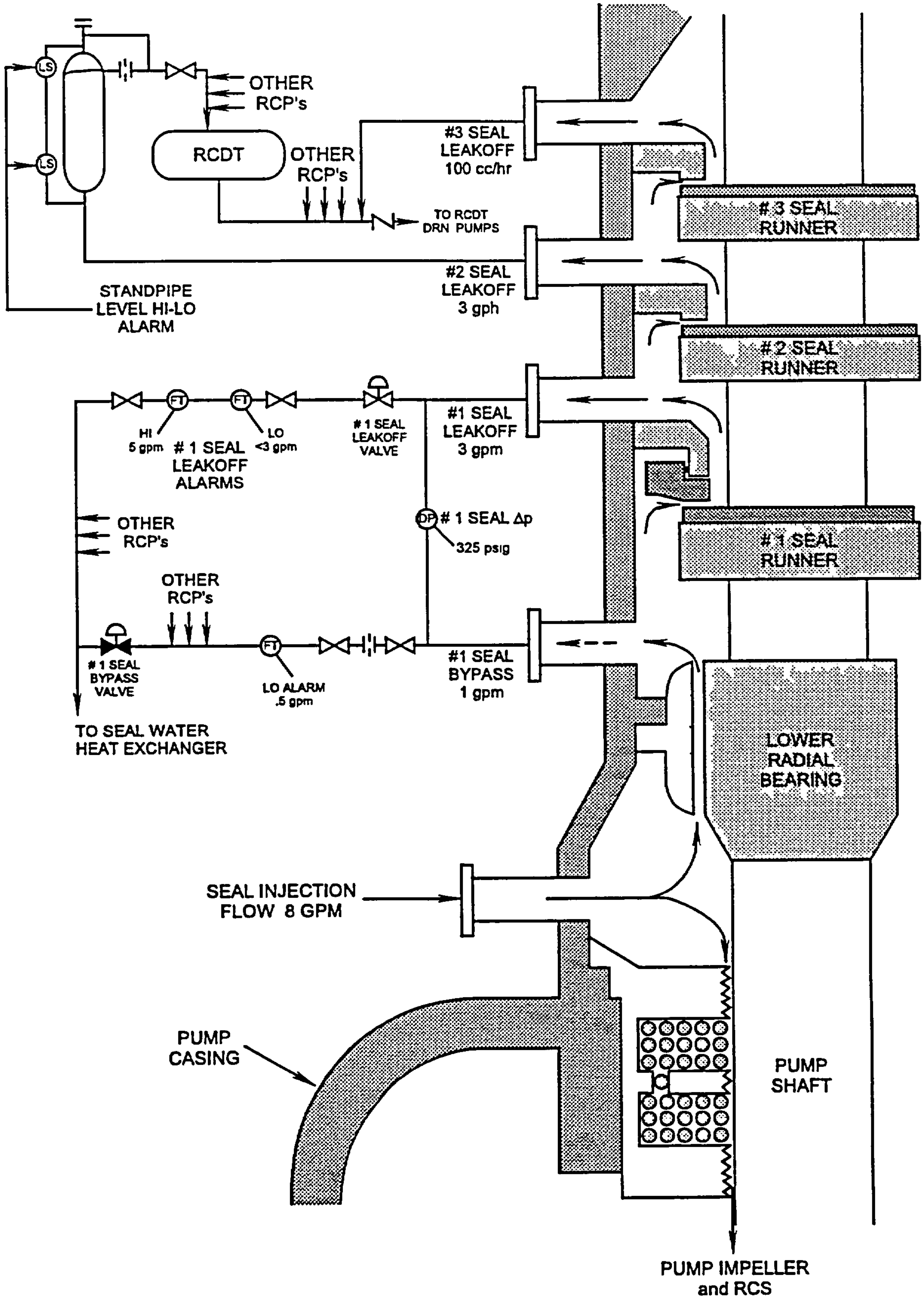


Figure 4.3-2 Seal Flow Diagram

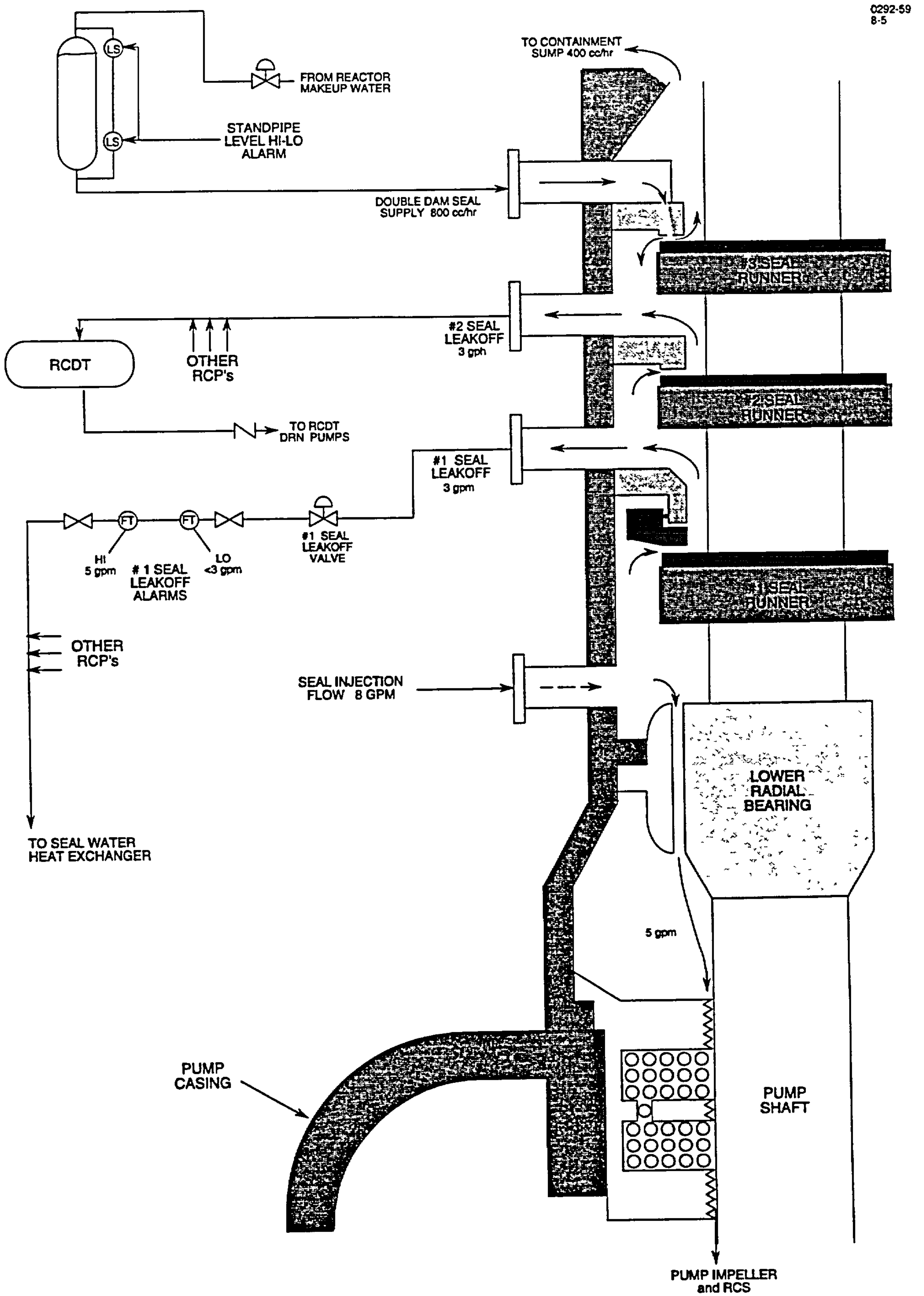


Figure 4.3-3 RCP Seal Assembly Westinghouse Model 93A-1

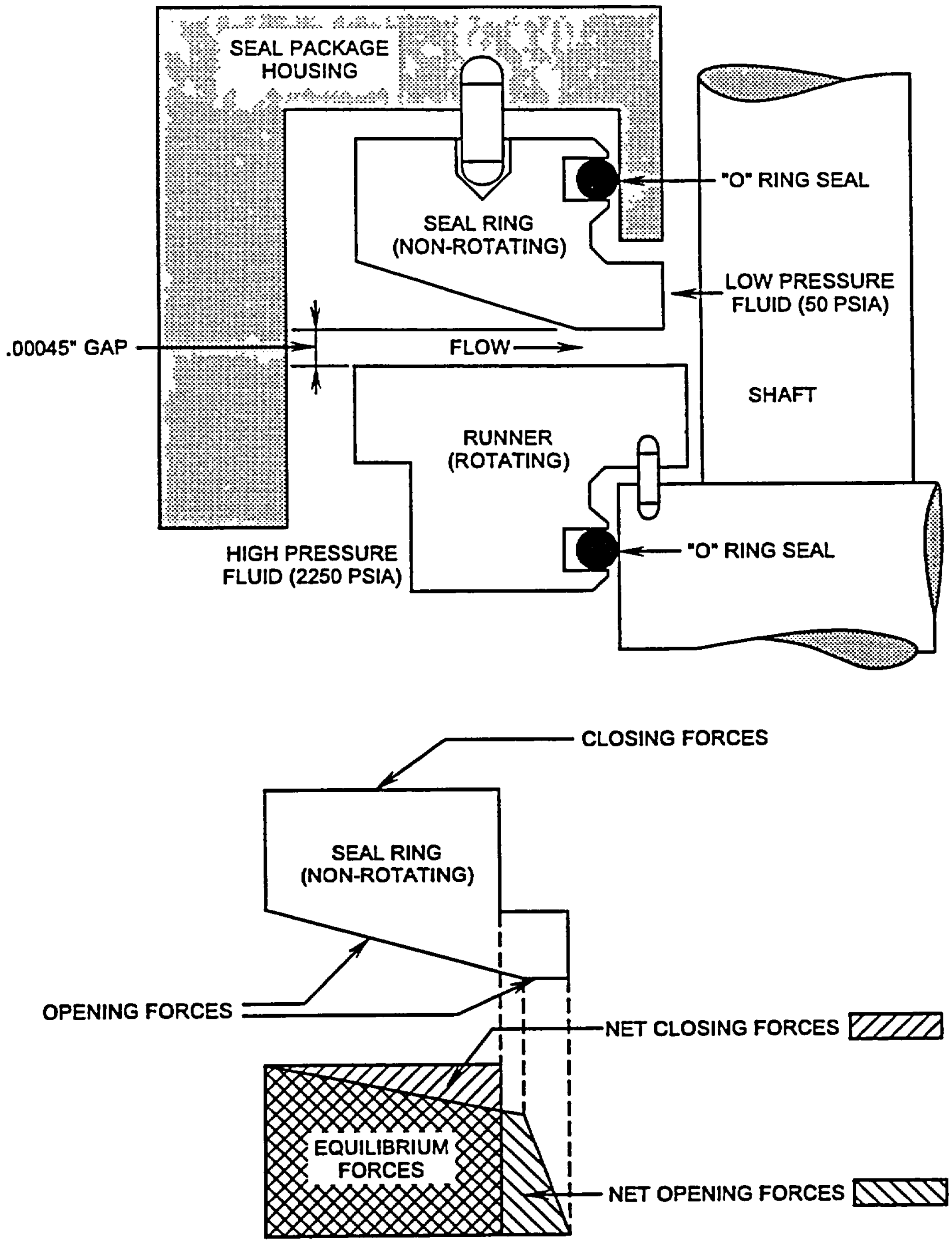


Figure 4.3-4 Controlled Leakage Shaft Seal

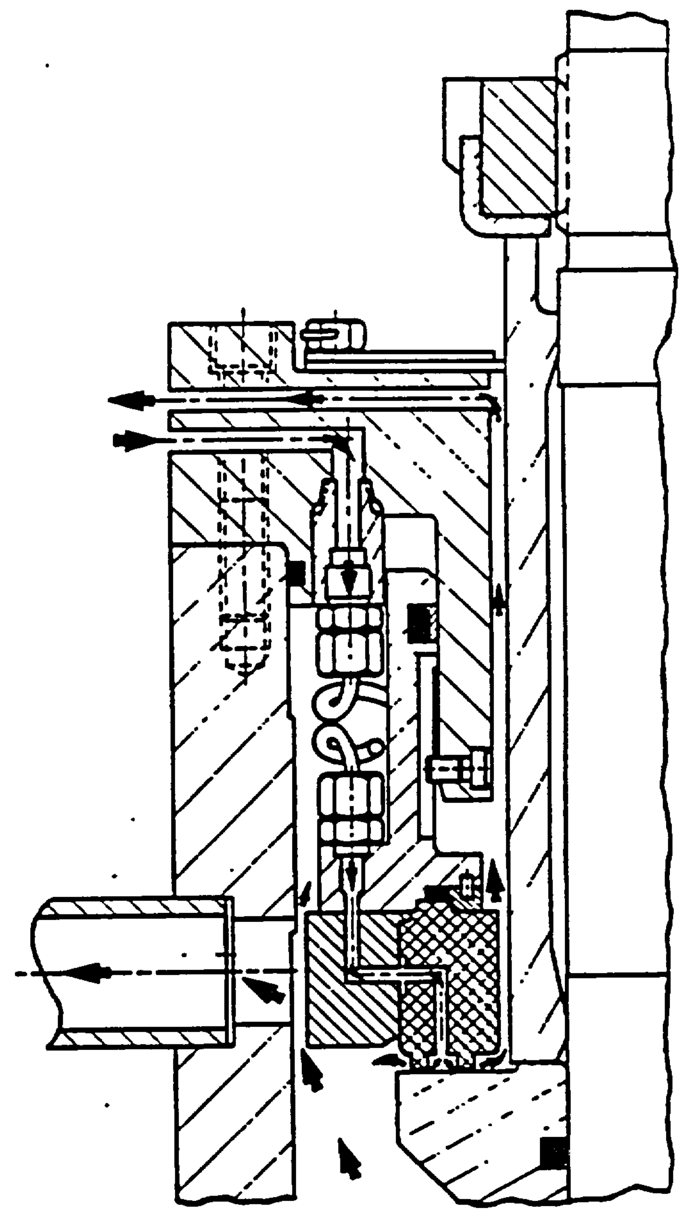


Figure 4.3-5 Double Dam Number 3 Seal

Westinghouse Technology Advanced Manual

Section 4.4

Reactor Coolant Pump Tripping Requirements

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

4.4 REACTOR COOLANT PUMP TRIPPING REQUIREMENTS

Learning Objectives:

1. Explain the effects on the reactor coolant system (RCS) inventory and peak clad temperatures following a small-break loss of coolant accident (SBLOCA) for the following conditions:

   a. Reactor coolant pumps (RCPs) tripped prior to the RCS draining to the break elevation.
   b. RCPs tripped after the RCS has drained to the break elevation.
   c. RCPs remain running throughout the transient.

2. Explain why it is advantageous to maintain the RCPs in operation during non-LOCA accidents.

3. State the basis for tripping the RCPs during SBLOCA conditions.

4. State the two criteria that must be satisfied prior to tripping the RCPs during an accident scenario.

5. List the three alternative RCP trip parameters.

6. Discuss the bases for the three alternative RCP trip parameters.

7. Discuss the methodology used to select the appropriate alternative RCP trip parameter.

4.4.1 Introduction

Tripping reactor coolant pumps under accident conditions has been under evaluation by the nuclear industry and the NRC, particularly after the event at Three Mile Island Unit 2 (TMI-2) and the steam generator tube rupture (SGTR) at the Ginna plant.

Section 4.4.2 presents background discussions on plant conditions (i.e., normal operation, anticipated transients, and accident conditions) during which an RCP trip may be required. A detailed description of the RCP trip criteria is provided in section 4.4.3.

4.4.2 Transient Description

4.4.2.1 Normal Operation and Anticipated Transients

The RCPs are designed to provide forced reactor coolant flow during all phases of plant power operation. The performance of the RCPs is one of several key component design parameters which is integrated into the overall plant design.

The performance of the RCPs must also be considered during the anticipated transients postulated for plant design. For most of the anticipated transients (Condition II events), the RCPs are assumed to remain in operation throughout the transient. However, in certain Condition II transients, the RCPs will be affected by the postulated transient. For example, a loss of offsite power will impact the operation of the RCPs (and other equipment). The RCPs normally receive power from the unit turbine-generator and should remain fully powered for a load rejection transient. For certain types of loss-of-load or turbine-trip transients, the RCPs would be switched to offsite power automatically, within 6 to 10 Hz. These conditions, too, should not result in any adverse impact on RCP operation.

One Condition II event that is integrally related to RCP performance is the partial loss of forced reactor coolant transient. For this event, the loss of one RCP is postulated, and an analysis is performed to determine the effects on core and plant performance. The specific cause of this transient is not significant because the transient analysis encompases a very broad range of mechanical and/or electrical faults which result in the trip of one RCP. The basis for the analysis is that the trip affects only one RCP, and that there is no consequential damage to other portions of the plant or to the pressure boundary function of the RCP. For these events, the RCP trip may be initiated manually by the operator or by any of a number of RCP protective trips.

The purpose of tripping an RCP during Condition I and II events is largely economic; an out-of-range parameter is indicative of an off-normal condition and the RCP is tripped to avoid continual degradation of the situation which could potentially result in damage to the RCP. During Condition III and IV events, the operator is also trained to trip the RCPs when off-normal conditions in the RCP support systems are encountered.

In summary, the RCP trips which can potentially occur during normal power operation are considered in the plant design. The trips are established largely to provide economic protection of the components and do not result in plant damage or challenges to the protective and/or safety systems.

4.4.2.2 Accident Conditions

The performance of the RCPs during accident conditions has been considered in component and plant design. In the plant safety analysis reports (SARs), RCPs are assumed to trip during accidents when an RCP trip would be detrimental to meeting safety criteria. Most frequently, the effect of an RCP trip deals with the lack of forced reactor coolant flow and effective heat removal from the reactor core. Other effects such as RCP overspeed, integrity, and missile generation have also been addressed.

During accident conditions, there are some situations which warrant an RCP trip. For example, during the initial stages of a small-break loss of coolant accident, if selected parameter setpoints are reached, the RCPs should be tripped to avoid more serious problems. During the long-term recovery from many accidents, it is desirable to trip selected RCPs to make recovery operations more easily achievable. These situations arise when the additional heat input to the RCS from the RCPs is large enough to hinder plant cooldown.

There are also situations in which the RCPs should remain operating or should be restarted if they have been removed from operation earlier in an accident sequence. These situations are associated with the need to provide normal pressurizer spray and forced RCS flow. Also, a RCP restart may be necessary in response to accident conditions beyond the plant design basis, such as an inadequate core cooling (ICC) condition.

For events within the plant design basis, safety and licensing criteria must be met assuming that the RCPs are not in operation. In almost every one of these cases, continued operation of the RCPs is beneficial. However, certain accident sequences have been identified in which it is possible that the accident is very negatively affected if the RCPs are tripped during a particular time interval. As a result, criteria have been developed to provide an RCP trip prior to reaching the critical time interval.

Loss of Coolant Accident (LOCA)

For large-break LOCAs (LBLOCAs), the operation of the RCPs has little if any effect during mitigation and recovery. During the initial phases of an LBLOCA, the RCPs are continuously powered for some minimum time period to avoid the possibility of RCP motor overspeed, since this could lead to the possibility of flywheel fracture and the attendant missile generation problems. For SBLOCAs, the primary concern is related not to the mechanical stability of the components but rather to the RCS coolant inventory and the impact on core heat removal.

Following the accident at TMI-2, industry and NRC attention focused on the role of RCP operation during SBLOCAs. The NRC issued IE-Bulletin 79-06, which required plant operators to ensure continued operation of at least one of the RCPs to provide forced cooling to the core. Industry evaluation of this directive pointed out conditions under which the SBLOCA conditions could be degraded rather than mitigated by such actions. The NRC then directed that RCPs be tripped if indications of a SBLOCA were obtained. The dialogue continued between the NRC and the industry until the NRC issued a revised position in NRC Generic Letters 83-10c and 10d. These letters recognize that there are certain accident conditions for which the RCPs should be tripped, and others for which RCP operation should be continued if possible. Under either set of accident conditions, safety criteria must be met and maintained for those events within the plant design basis.

Extensive analyses have been performed for Westinghouse pressurized water reactors (PWRs) to evaluate the effect of an RCP trip during SBLOCAs. These analyses were performed utilizing the Westinghouse Small Break Evaluation Model and the results were presented in WCAP-9584. The safety analyses for Westinghouse PWRs contain analyses of a spectrum of small break sizes in which the loss of offsite power, and thus an RCP trip, is assumed to occur coincident with the reactor trip. In the WCAP-9584 study, a range of break sizes and locations was considered assuming an RCP trip at various times following break initiation.

Evaluation of the cases included in the WCAP-9584 study indicates two distinct characteristic behavior modes, depending on the RCP trip time. This is illustrated in Figure 4.4-1, which presents integrated break discharge mass versus time for various RCP trip times. The change of slope of each curve in Figure 4.4-1 represents a shift in break flow quality from nearly zero (all water) to one (mostly steam), as the RCS drains to the break elevation. Case A is the final safety analysis report (FSAR) three-in.-diameter break calculation for a three-loop plant design, in which an RCP trip at the time of reactor trip is assumed. For Case A, the RCS drains to the break elevation and the break flow changes to all steam flow at approximately 575 seconds after break initiation. Cases B and C represent scenarios in which the RCP trip occurs prior to the time the RCS drains to the break elevation. Figure 4.4-1 illustrates that the difference in the total mass depletion is insignificant for these cases. Therefore, the liquid mass inventory remaining in the RCS is also comparable, yielding peak clad temperatures (PCTs) similar to the FSAR case results, which are below the regulatory limit of 2200°F.

Cases D through G represent scenarios in which the RCPs remain running for times equal to or greater than the time required for the RCS to drain to the break elevation; they demonstrate significant differences in the total mass depletion through the break. Forced flow induced by RCP operation maintains the inner vessel mixture level above the hot-leg nozzle elevation. This allows for continued circulation of liquid around the loops, providing a source of liquid to the break region. Therefore, continued RCP operation prolongs the period of liquid break discharge as the RCS drains. The difference in time of the slope change for the delayed RCP trip cases is associated with additional mass loss through the break. The prolonging of the liquid break discharge further depletes the liquid mass inventory remaining in the RCS. Immediately following the RCP trip for these cases, loop flow rates decrease and steam/water phase separation occurs. A rapid reduction in the vessel mixture level results, and the fuel may be partially uncovered. Prolonged RCP operation and the resultant additional liquid mass depletion can greatly affect the degree and duration of core uncovery. Depending on plant type and break size, a range of RCP trip times may yield PCTs greater than the FSAR case result.

The effect of RCP trip time on calculated PCTs is illustrated in Figure 4.4-2. As can be seen for a break size of three in. in diameter, if the RCPs are tripped during the time interval of 575 - 650 sec following the break initiation, the resulting peak clad temperature would exceed the limit of 2200°F. This is also true for a two-in. break and RCP trip after 2,000 sec.

If the RCPs remain operational throughout the transient (Case H of Figure 4.4-1), depletion of primary liquid mass is maximized. However, the PCTs remain well below the FSAR case results due to enhanced core cooling caused by the high core steam flow rates associated with two-phase loop flow. Continuous operation of the RCPs during a LOCA cannot be guaranteed, since tripping of the RCPs would occur upon a loss of offsite power or other essential support conditions, which can be postulated to occur at any time. The reason for purposely tripping the RCPs during accident conditions is to prevent excessive depletion of the RCS water inventory through a small break in the RCS, which might lead to severe core uncovery if the RCPs were tripped for some reason later in the accident. The RCPs should be tripped before the RCS liquid inventory is depleted to the point where tripping of the pumps would cause the break to immediately uncover.

Non-LOCA Accidents

During virtually all non-LOCA accidents, it is advantageous to have the RCPs in operation. Continued RCP operation provides additional margin to safety criteria limits and makes operator actions during recovery easier. However, whether the RCPs remain in operation or are tripped, safety criteria must be met. Plant operators are provided with guidance to mitigate and recover from accidents. For accidents involving the loss of secondary coolant, control of RCS pressure, RCS temperature, and pressurizer level is the major concern, rather than core cooling. For the various types of SGTR events (either single or multiple ruptures), control of the leak rate, RCS pressure, RCS temperature, and pressurizer level is important. In all cases, RCP operation provides enhanced core heat removal and makes RCS pressure control by the operator a more straightforward matter. In general, for non-LOCA accidents, it is desirable to have the RCPs in operation throughout the event to:

1. Maintain normal pressure control using pressurizer spray and thereby avoid opening of the pressurizer power-operat-

ed relief valves (PORVs),

2. Prevent the formation of a stagnant water volume in the upper head region of the vessel, which may flash and form a steam bubble during the subsequent cooldown and depressurization,
3. Minimize potential pressurized thermal shock challenges, and
4. Minimize operator actions such as tripping the RCPs and then restarting them later.

The NRC has required development of RCP trip setpoints based on parameters which allow the operation of some (or all) of the RCPs during those accidents which will benefit from RCP operation, yet result in a trip of the RCPs for SBLOCAs and other accidents which require it.

4.4.3 RCP Trip Criteria

The RCP trip criteria have been developed and incorporated into the emergency operating proceduress to require RCP trip when required (e.g., in response to an SBLOCA) and to minimize the probability of an RCP trip when one is not required. The RCP trip criteria consist of two fundamental parts:

1. Successful operation of the safety injection (SI) system and
2. Selected plant parameters reaching critical setpoints.

In the Westinghouse emergency operating procedures, the RCPs are not tripped unless these criteria are satisfied. It cannot be emphasized too strongly that a fundamental condition which must be satisfied for an RCP trip during an emergency condition is that at least one high pressure SI pump be in operation and capable of delivering flow to the RCS. If this fundamental condition is not met, the RCPs should not be tripped regardless of whether the plant parameters indicate that a trip setpoint has been reached. Analysis has shown that if the SI system is not in operation, the RCPs can be operated to provide core heat removal. For SBLOCAs with the high-head safety injection pumps not in operation, the RCPs continue to provide core heat removal via the break and the SGs. With the RCPs running, the RCS can safely be depressurized to the point where the accumulators and the low-head safety injection pumps can ensure core heat removal before symptoms of inadequate core cooling are exhibited. If the RCPs are tripped during the RCS depressurization because of a loss of offsite power or other support condition, the depressurization rate can be increased to the maximum rate to obtain the benefits of injection from the accumulators and low-head safety injection pumps sooner.

4.4.3.1 Alternative RCP Trip Parameters

It is possible to conservatively establish a parameter and corresponding setpoint which can be used as a symptom for operator action to ensure that the RCPs are tripped early during a small-break LOCA. However, the use of an overly conservative parameter and setpoint could also result in an RCP trip during a steam generator tube rupture or other non-LOCA accidents for which it is desirable to keep the RCPs running. Therefore, it is desirable to have an RCP trip parameter and setpoint which ensure a pump trip for the range of small-break LOCAs during which a pump trip is required, but do not lead to a pump trip for most SGTRs and non-LOCA accidents. Tripping the RCPs for an SGTR or non-LOCA accident would not violate any safety criteria. The design of plant safety systems and the FSAR analyses for these accidents are based on the concurrent loss of offsite power and thus on a concurrent RCP trip.

In NRC Generic Letters 83-10c and 10d, the NRC addressed the question of developing RCP trip setpoints. The NRC concluded that the need for an RCP trip following a transient or accident should be determined by each plant, with consideration of Owners Group input, and provided guidance for the development of satisfactory RCP trip setpoints. This guidance indicated that the setpoints should be designed to ensure that the RCPs would be tripped for all LOCAs for which an RCP trip is considered necessary, but should also ensure continued RCP operation during SGTRs up to and including the design-basis tube rupture. The evaluation to establish the RCP trip parameters and setpoints should be capable of demonstrating and justifying that the proposed RCP trip parameters and setpoints are adequate for SBLOCAs, but would not result in an RCP trip for other non-LOCA transients and accidents (e.g., SGTRs).

For a small-break LOCA, the RCP trip parameter must provide an indication of the need for an RCP trip before the RCS coolant inventory decreases to the point where the break would be uncovered if the RCPs were tripped. Parameters that are indicative of decreasing RCS coolant inventory should be suitable for use as potential RCP trip parameters. The evaluation of alternative RCP trip parameters was limited to parameters which could be measured with existing qualified instrumentation. The alternative RCP trip parameters which have been evaluated are RCS pressure, reactor coolant subcooling, and steam-generator-pressure-dependent RCS pressure.

In establishing the setpoint for any of the potential RCP trip parameters, the uncertainty in the instrument readings must be considered. One of the factors which can affect the instrument uncertainty is environmental conditions. The environmental conditions inside the containment during an accident can vary, depending on the type and severity of the accident, from normal conditions to the worst case post-accident conditions.

Although a large LOCA or secondary break inside containment may result in adverse containment conditions, there are many LOCAs and other non-LOCAs which are not expected to result in adverse containment conditions. In addition, a design-basis SGTR is not expected to result in adverse containment conditions, even for those plants in which the condenser air ejector exhaust is diverted to the containment on a high radiation indication. If adverse containment conditions exist, then the setpoint with instrument uncertainties associated with post-accident containment conditions should be utilized in determining the need for an RCP trip, whereas the setpoint with normal instrument uncertainties should be used if adverse containment conditions do not exist. This requires the use of two RCP trip setpoints in the procedures, with the appropriate one being selected by the operator based on an indication of containment conditions. Since most SGTR and non-LOCA events are not expected to result in adverse containment conditions, the lower setpoint resulting from the use of normal instrument uncertainties reduces the likelihood of tripping the RCPs for these events.

RCS Pressure

The purpose of tripping the RCPs during accident conditions is to prevent the excessive depletion of RCS inventory through a small break. RCP operation does not lead to excessive RCS inventory loss through the break until the time is reached when tripping the RCPs would cause the break to immediately uncover. The break cannot be uncovered until the steam generator tubes have begun to drain. Also, the steam generator tubes cannot begin draining until saturation pressure is reached at the top of the steam generator tubes. Only then can steam reside in the top of the steam generator tubes and volumetrically compensate for the falling liquid level.

Therefore, the objective is to establish an RCP trip setpoint which is indicative of saturation pressure being reached at the top of the steam generator tubes. The determination of this saturation pressure depends on the conditions in the primary system, the conditions in the steam generator secondary side, and the location and accuracy of the instrumentation used.

A bounding decay heat generation rate at two minutes after a reactor trip from full power will be used to determine the primary system conditions. The value of decay heat at this time is about 3.5 percent of full reactor power. The RCP heat input to the primary system should also be included. With the RCPs operating, the primary system is able to transfer the 3.5 percent decay heat and RCP heat input with a very small change in the reactor coolant temperature across the core. However, the actual temperatures in the RCS will depend on the conditions in the steam generator secondary side.

The pressure in the steam generator secondary side will depend on the availability of the condenser for steam dump operation and the operability of the secondary PORVs. The highest pressure in the steam generator secondary side will occur if the condenser is not available, the secondary PORVs are not operable, and the steam generator secondary side pressure is established by the safety valves. These are the steam generator secondary side conditions that will be used to determine the RCS pressure setpoint for an RCP trip because they result in the highest possible saturation pressure during a small LOCA. Therefore, the steam generator pressure is assumed to be established by the steam generator safety valve set pressure.

The RCS pressure setpoint that is determined from this steam generator pressure is developed in accordance with the following considerations. The RCS wide-range pressure used for this purpose is normally measured in the hot leg. There is a pressure drop between the RCS pressure measurement location and the top of the steam generator tubes (where the occurrence of saturation is key), a pressure difference across the steam generator tubes due to the temperature gradient required for heat transfer, and a pressure drop from the top of the steam generator tubes to the steam generator safety valves. Thus, the RCS pressure for RCP trip should be the pressure established by the steam generator safety valves plus the calculated pressure differential from the steam generator safety valves to the RCS pressure measurement location.

The appropriate instrument uncertainties should be added to the RCS pressure value established by the above procedure. For normal containment conditions, the normal instrument uncertainties should be used, whereas with adverse containment conditions, the instrument uncertainties associated with post-accident containment conditions should be used. The resulting two pressures are the RCS pressure setpoints at which the operator should trip the reactor coolant pumps, depending upon the containment conditions.

RCS Subcooling

As discussed previously, RCP operation following a small-break LOCA does not lead to excessive RCS liquid inventory loss through the break until the time is reached when tripping the RCPs would cause the break to immediately uncover. The break cannot be uncovered until a significant amount of voiding has occurred in the RCS. Since it is expected that voiding will occur first at the core exit, it is not necessary to trip the RCPs as long as subcooling is maintained in the RCS hot legs. RCS subcooling based on the temperature measured by either the wide-range hot-leg resistance temperature detectors (RTDs) or the core-exit thermocouples can be used for this purpose. To ensure a conservative RCP trip setpoint when subcooling is lost, the instrument uncertainties associated with RCS subcooling must also be considered. The RCP trip setpoint using RCS subcooling would be zero degrees plus instrument uncertainties.

Secondary-Pressure-Dependent RCS Pressure

The RCS pressure parameter described above provides for tripping the RCPs at the time when saturation pressure is reached at the top of the steam generator tubes. This RCS pressure setpoint is based on the conservative assumption that the steam generator pressure is fixed at the steam generator safety valve set pressure. However, the steam generator pressure may actually be less than this value, depending on the availability of the steam dump system and the steam generator PORVs. With the method described in this subsection, the RCS pressure setpoint is determined based on the actual steam generator pressure.

The RCS pressure for RCP trip would be the highest indicated steam generator pressure, plus the calculated pressure differential from the steam generator pressure measurement location to the RCS pressure measurement location. This pressure differential consists of the pressure drop between the RCS pressure measurement location and the top of the steam generator tubes, the pressure difference across the steam generator tubes due to the temperature gradient required for heat transfer, and the pressure drop from the top of the steam generator tubes to the secondary pressure measurement location.

The appropriate instrument uncertainties should be added to the RCS pressure value established above. For normal containment conditions, the normal instrument uncertainties should be used, whereas with adverse containment conditions, the instrument uncertainties associated with post-accident containment conditions should be used. The instrument uncertainties should be determined for both the RCS pressure measurement and the steam generator pressure measurement, and the values should be combined in an appropriate manner to obtain the total uncertainty. The resulting two pressures are the indicated RCS pressure setpoints at which the operator should trip the RCPs, depending on the steam generator pressure and the containment conditions. To facilitate the use of this parameter, a curve or table can be used which shows the RCS pressure setpoint for RCP trip as a function of steam generator pressure for normal and for adverse containment conditions.

4.4.3.2 Evaluation of Alternative RCP Trip Parameters

Analyses have been performed to evaluate the effectiveness of the three alternative RCP trip parameters for small-break LOCAs, SGTRs and non-LOCA accidents. For each of the accidents, a design-basis accident was defined and analyses were performed for representative Westinghouse plants. The objective of the small-break LOCA analysis was to demonstrate that tripping the RCPs in accordance with one of the the alternative parameters ensures that the RCPs are tripped prior to the time when a trip is actually required.

The results of the small-break LOCA analysis demonstrate that the three alternative RCP trip parameters (RCS pressure, RCS subcooling, and RCS/steam generator ΔP) are essentially equivalent in providing an effective indication to the operator to trip the RCPs during a small-break LOCA. The results also show that each of the parameters will provide the indication for an RCP trip sufficiently early such that more than two minutes are available for operator action between the time the RCP trip setpoint is reached and the time when a trip is required. This was demonstrated for each of the RCP trip parameters without adding any instrument uncertainty in determining the RCP trip setpoints. Each of the alternative RCP trip parameters will satisfactorily indicate the need for an RCP trip during a small-break LOCA with the instrument uncertainties based on either normal or adverse containment conditions. Because each of the alternative RCP trip parameters is provides a timely indication of the need for a trip during a small-break LOCA, the choice of which one to implement at a given plant may therefore be based on its discrimination capability for SGTRs and non-LOCA accidents and on other plant specific instrumentation considerations.

For the SGTR and non-LOCA events, design-basis accidents were defined and analyses were performed to determine the behavior of the alternate RCP trip parameters. The design-basis SGTR was defined as a double-ended rupture of one steam generator tube on the outlet side of the steam generator. The non-LOCA analyses were performed for credible steam line and feed line breaks since it was determined that these accidents result in the most limiting transients among the non-LOCA accidents considered. The design-basis steam line break was defined as an unisolable break approximately 4.5 in. in diameter in one steam line, which is equivalent to one steam generator PORV failing open. For the feed line break, a full double-ended rupture of one main feedwater pipe was assumed to occur between the steam generator and its associated feed line check valve. The SGTR and non-LOCA analyses were performed for 100 percent steady-state power using best-estimate assumptions. These assumptions provide for a realistic assessment of the capability of each parameter to prevent an RCP trip for these accidents.

It should be noted that the objective of the SGTR and non-LOCA analyses was to consider these design-basis accidents with realistic assumptions to enable the development of an RCP trip parameter which would provide reasonable assurance of continued RCP operation for these accidents. It is possible that various other accident conditions could result in more limiting parameter values than those obtained from these analyses. However, the design-basis accidents which were defined for the analyses, combined with the conservatisms which are incorporated in the analytical model, provide assurance that the analysis results will be bounding for most SGTR and non-LOCA events. It would not violate any safety criteria if the RCPs are tripped during an SGTR or non-LOCA event, since the plant safety systems are designed to handle those accidents with a loss of offsite power and, therefore, with an RCP trip. It is desirable, however, to ensure that the RCPs remain operating during most of the expected cases of these accidents, so that the operator can retain normal pressurizer pressure control and is not required to open the pressurizer PORVs. Since the primary reason for this study is to provide information which will facilitate operator actions, it is reasonable to use realistic analysis results for the SGTR and non-LOCA events.

Analyses were performed for the defined design-basis SGTR, feed line break, and steam line break for representative Westinghouse plants. The RCS pressure, RCS subcooling and RCS/steam generator ΔP values were calculated for a total transient time of 10 minutes from the event initiation, and the minimum values of these parameters were determined for each transient. The transient time of 10 minutes was considered to be a reasonable interval in which an operator could evaluate the need for an RCP trip immediately following the design-basis SGTR, feed line break, or steam line break. For the feed line and steam line breaks, the potential RCP trip parameter values reach a minimum within 10 minutes and are stable or increasing at the end of this interval. However, since no operator actions were assumed for the analysis, the continued addition of full auxiliary feedwater flow to the steam generators results in a gradual cooldown of the RCS during the design-basis SGTR. This cooldown causes some of the potential RCP trip parameter values to continue to slowly decrease, such that their minimums are not reached during the 10-minute period. However, in accordance with the emergency operating procedures, it is expected that operator action will be taken within 10 minutes during a design-basis SGTR to throttle the auxiliary feedwater flow to control the levels in the steam generators. This action tends to stabilize the RCS conditions at the point where the safety injection flow rate is approximately equal to the break flow rate. Thus, it is expected that the minimum values of the RCP trip parameters calculated for the 10-minute transient period conservatively bound the expected values for the design-basis SGTR.

The SGTR generally results in the minimum values of the potential RCP trip parameters. The minimum values of RCS pressure, RCS subcooling and RCS/steam generator pressure differential were determined from the SGTR, steam line break, and feed line break analyses for each of the categories of Westinghouse plants; the results are presented in Table 4.4-1. These results represent the minimum values of these parameters for SGTRs and non-LOCA accidents and are to be compared to the appropriate RCP trip setpoints for each plant after they have been developed by the utilities using plant specific information. This comparison will enable each of the utilities to determine which of these alternative parameters is most effective in preventing an RCP trip for SGTRs and non-LOCA accidents for its respective plants.

4.4.3.3 Selection of RCP Trip Parameter

Since it was determined that the three alternative RCP trip parameters are equally effective in in providing an indication of the need for an RCP trip for a small-break LOCA, the parameter selection can be based on the capability to prevent an RCP trip for SGTRs and non-LOCA accidents. In order to determine which of the parameters prevents an RCP trip for SGTRs and non-LOCA accidents, it is necessary for each plant to determine an RCP trip setpoint for each of the parameters. If the setpoint for any of the parameters for a specific plant is less than the minimum value of the corresponding parameter in Table 4.4-1 for that plant, then that parameter would be effective in preventing a pump trip for SGTRs and non- LOCA accidents, and would satisfy the discrimination requirement in Generic Letters 83-

10c and 10d.

It is noted that the setpoint for the RCS pressure parameter is dependent on the steam generator safety valve set pressure. In addition, the setpoints for each of the parameters are dependent on the instrument uncertainties associated with that parameter, which are plant specific. These considerations result in different setpoints for each of the parameters for most of the plants. The results in Table 4.4-1 also show that there is a significant variation in the minimum values of the potential RCP trip parameters between the different plants. Based on these results, it is expected that some of the plants can demonstrate an acceptable discrimination capability to prevent an RCP trip for SGTRs and non-LOCA accidents with any of the three alternative parameters, whereas some of the plants will only be able to demonstrate an acceptable discrimination capability with one or two of the parameters. There may also be other plant-specific considerations, such as instrument qualification, operator training, human factors, etc., which could influence the selection of the RCP trip parameter. Thus, it would not be practical to generically select one parameter which would provide the required discrimination and also be the most suitable choice for all of the plants.

On this basis, it was decided that each utility would evaluate the discrimination capability of the parameters and then determine which RCP trip parameter should be used for its plant. The RCP trip setpoints for the alternative RCP trip parameters can be determined for each of the plants based on the plant design and instrument uncertainties. The RCP trip parameter setpoints for each plant can then be compared with the minimum values of RCS pressure, RCS subcooling, and RCS/steam generator pressure differential to determine which of the criteria are effective in preventing an RCP trip for SGTRs and non-LOCA accidents. The utility can then select the most suitable parameter for its plant based on this information and any other plant-specific considerations.

As an example, the RCP trip setpoints have been determined for a sample plant and are compared with the limiting SGTR and non-LOCA accident results in Table 4.4-2. The sample plant is a three-loop plant with a high pressure safety injection system, type 51 steam generators (tube I.D. of 0.775 in.), and a no-load temperature of 547°F. The limiting results of the SGTR and non-LOCA analyses for the sample plant are the same as those presented in Table 4.4-1 for the Farley, North Anna, Surry, and Beaver Valley plants. The RCP trip setpoints for the sample plant were determined for both normal and adverse containment conditions. The RCP trip setpoints presented in Table 4.4-2 for the sample plant are intended only as an example, and are not intended to represent recommended values for use by any plants, since only typical instrument uncertainties were used. As shown in Table 4.4-2, the minimum RCS pressure from the SGTR and non-LOCA analyses is less than the corresponding RCP trip setpoint with normal containment conditions, whereas the minimum RCS subcooling and RCS/steam generator pressure differential are greater than their respective RCP trip setpoints with normal containment conditions. Thus, for the sample plant, the use of the RCS pressure parameter would not be effective in precluding an RCP trip for the design-basis SGTR and non-LOCA events and would not meet the discrimination requirement in Generic Letters 83-10c and 10d. However, the use of either the RCS subcooling or the RCS /steam generator pressure differential parameter would effectively preclude an RCP trip for SGTRs and non-LOCA accidents for the sample plant and would satisfy the NRC discrimination requirement. The companion RCP trip setpoints which would be used with adverse containment conditions for the sample plant are also presented in Table 4.4-2 for completeness. Each utility must perform an evaluation similar to that in Table 4.4-2 for its plants.

4.4.3.4 Calculation of RCP Trip Parameter Setpoint (RCS Pressure)

The steps for calculating the RCP trip setpoints based on RCS pressure are discussed below. The setpoints for both normal and adverse containment conditions are calculated. The instrument uncertainties are calculated on a plant-specific basis for both normal and adverse containment conditions to determine the setpoints.

The formula for determining the RCP trip pressure setpoint is given in the following three steps:

1. Secondary System Pressure: Based on the number and size of the secondary system safety valves, the secondary pressure will be established by determining the pressure setpoint for that valve in which the calculated steam relief is less than 60 percent of the valve's relief rating. If the calculated steam relief is greater than 60 percent of the rated capacity, then the next highest pressure setpoint should be used.

2. RCS Pressure: The RCS pressure for RCP trip should be the secondary pressure as established by step 1 above plus the calculated pressure difference from the secondary safety valves to the RCS pressure measurement location. This pressure differential should include the pressure drop from the top of the steam generator tubes to the secondary safety valves, the pressure difference across the steam generator tubes due to the temperature gradient required for heat transfer, and the pressure drop from the RCS pressure measurement location to the top of the steam generator tubes.

3. The appropriate instrument uncertainties should be added to the primary system pressure value established in step 2 above. For normal containment conditions, the normal instrument uncertainties should be used, whereas with adverse containment conditions, the instrument uncertainties associated with post-accident containment conditions should be used. The resulting pressures are the RCS pressure setpoints at which the operator should trip the reactor coolant pumps, depending on the containment conditions.

A sample calculation is performed in the following ten steps:

1. Decay Heat Level: For all plants, the decay heat generation rate used in this determination is 3.5 percent of full reactor power.

2. Steam Flow Rate - Using 3.5 percent decay heat and RCP heat addition, calculate the required steam flow to be vented through the steam generator safety valves in the absence of condenser and atmospheric relief capability:

HEAT INPUT PER STEAM GENERATOR,

$$Q = \frac{\text{Core Power (Mwt)} \times \text{(Decay Heat Fraction)}}{\text{Number of Loops}}$$

$$+ \text{RCP Heat}$$

For a three-loop, 2785-MWt plant, with 2775 MWt core power and 10 MWt RCP heat input:

$$Q = \left(\frac{2775\ \text{MWt}}{3\ \text{Loops}} \times 0.035 + \frac{10\ \text{MWt}}{3\ \text{Loops}} \right) \times$$

$$3412141\ \frac{\text{BTU}}{\text{MW-hr}} = 1.218 \times 10^8\ \frac{\text{BTU}}{\text{hr-Loop}}$$

For conservatism and ease of calculation, assume that the heat input will be used to evaporate saturated water in the steam generator shell:

STEAM FLOW RATE PER LOOP,

$$M = \frac{Q}{\text{Latent Heat of Vaporiztion } (H_{fg})}$$

where H_{fg} is chosen at the lowest safety valve setpoint pressure. For a three-loop, 2785-MWt plant with type 51 steam generators and a 1100-psia shell design pressure, the lowest safety valve setpoint can be no higher than 1100 psia. Therefore:

$$M = \frac{1.218 \times 10^8\ \text{BTU/hr-Loop}}{631.5\ \text{BTU/lbm}} =$$

$$1.929 \times 10^5\ \frac{\text{lbm}}{\text{hr-Loop}}$$

For such a plant, the rated steam flow at 100 percent power is about 4.04×10^6 lbm/hr-Loop, so the above calculation yields a steam flow that is about five percent of the rated flow. Generally, the rated steam flow for a given loop assumes that all RCPs are operating. Some plants have one or more RCP motors powered by the station turbine-generator. Subsequent to the turbine trip, this power source is lost, and unless the source of power for these pumps is automatically transferred to offsite power, credit should not be taken for the idle pumps and loops for the above portion of the calculation.

Each utility must use its plant's rated power, number of loops, shell design pressure, and latent heat of vaporization corresponding to that shell pressure.

3. Safety Valve Set Pressure Selection: Using the steam flow rate/loop determined in step 2 and the capacity and set pressures of all the steam generator safety valves on one main steam line, determine how many safety valves must open such that the steam flow is less than or equal to 60 percent of the cumulative capacity of those valves. Since a typical safety valve relieves about 20 percent of the rated steam flow for a given loop, it is expected that the steam flow derived in step 2 will be less than 60 percent of the capacity of the steam generator safety valve having the lowest set pressure. For the sample plant this safety valve has a set pressure of 1100 psia (1085 psig). Each utility must use the capacities and set pressures of its plant's safety valves in this determination.

4. Uncertainties on the Steam Generator Safety Valve Opening Pressure: While the safety valve in the above example is set to

open at 1100 psia, the ASME Boiler and Pressure Vessel Code, Section NC-7600, only requires that the safety valve achieve a full open/full capacity condition with 103 percent accumulated pressure. Since the actual steam flow required is probably considerably less than the valve capacity, the valve may partially open and remain open in a partially open position. Therefore, the steam generator pressure at any time may be as much as three percent (or 33 psi for a 1100 psia set pressure) above the set pressure of the chosen safety valve. The three percent value applies to all plants. Also, the code allows for a one percent tolerance on the popping pressure from the set pressure. This one percent tolerance is included in the three percent accumulated pressure allowance, since both are applied to the set pressure.

5. <u>ΔP Between the Safety Valves and the Steam Generator Shell</u>: Since the pressure of interest is that which exists in the tube region of the steam generator secondary side, the pressure differential between that location and the safety valves must be taken into account. Typically, this ΔP for rated steam flow is about 20 - 30 psi. At five percent of rated steam flow, therefore, the ΔP should be about 30 psi x $(0.05)^2 = 0.075$ psi. A value of one psi is chosen to bound the situation. Each utility should verify that the rated steam flow ΔP for its plant does not make this number greater than one psi.

6. <u>ΔP Across Steam Generator Tubes</u>: The sample plant steam generators have a log-mean-temperature difference (LMTD) of 47.2°F (primary to secondary) at full power. The LMTD must be determined for 3.5 percent power with the secondary temperature at saturation for the steam generator safety valve set pressure plus three percent accumulation. This requires the calculation of the primary inlet and outlet temperatures needed to transfer 3.5 percent reactor power plus the RCP heat input at this secondary temperature. This calculation requires an iterative solution, since the overall heat transfer coefficient is dependent upon the temperatures. At 3.5 percent power, the LMTD is 3.0°F for the sample plant. Thus, at the top of the steam generator tubes there is approximately a 3.0°F ΔT (primary to secondary). At the set pressure plus three percent accumulation for the chosen steam generator safety valve, this corresponds to about a 27 psi change in saturation pressure. So the saturation pressure in the top of the tubes of the steam generator is about 27 psi above the steam generator pressure. Each utility must perform the above calculation of ΔP based on its expected plant conditions.

The LMTD used above assumes that all RCPs are operating. Some plants have one or more RCP motors powered by the station turbine-generator. Subsequent to a turbine trip, this power source is lost, and unless the source of power for these pumps is automatically transferred to offsite power, credit should not be taken for the idle pumps and loops for the above calculation.

The LMTD for the above determination can be rigorously calculated or can be conservatively estimated using the following simplified method.

The LMTD is calculated using the following equation:

$$LMTD = \frac{(T_{hot} - T_{cold})}{\ln\left[\frac{(T_{hot} - T_{sec})}{(T_{cold} - T_{sec})}\right]}$$

where: T_{hot}=Vessel Outlet Temperature (°F)

T_{cold}=Vessel Inlet Temperature (°F)

T_{sec}=Secondary Steam Temperature (°F)

The reactor coolant ΔT (T_{hot} - T_{cold}) at 3.5% power is calculated by:

$$\Delta T_{3.5\%Power} = \Delta T_{Full\ Power} \times \text{Power Fraction}$$

where: $\Delta T_{Full\ Power} = T_{hot} - T_{cold}$ (from 100% power calc.)

$$\text{Power Fraction} = \frac{\text{NSSS Power @ 3.5\%}}{\text{NSSS Power @ 100\%}}$$

NSSS Power @ 3.5% =
Core Power x 0.035 + RCP Heat Input

If it is conservatively assumed that, at 3.5% power:

$T_{cold} = T_{sec} + \Delta T_{3.5\%Power}$, then:

$$T_{hot} = T_{cold} + \Delta T_{3.5\%Power} = T_{sec} + 2\,\Delta T_{3.5\%Power}$$

Substituting these values into the LMTD equation gives:

$$LMTD_{3.5\%Power} = \frac{\Delta T_{3.5\%\ Power}}{\ln 2} = 1.433\,\Delta T_{3.5\%\ Power}$$

The LMTD at 3.5% power can be conservatively estimated using this relationship. It should be noted that the estimated LMTD using this method is not dependent on the secondary steam temperature.

7. <u>ΔP Between the Wide-Range RCS Pressure Instrument and the Top of the Steam Generator Tubes</u>: The reactor coolant pressure drop across a typical steam generator is 30 - 40 psi. Also, there is a small ΔP between the pressure tap in the hot leg and the entrance to the steam generator. Therefore, during a LOCA the fluid in the top of the steam generator tubes will reach saturation pressure before the pressure tap indicates it. Therefore, a ΔP should be included in the final RCP trip setpoint pressure to account for this. A value equal to half of the total steam generator pressure drop during normal operation is adequate (i.e., 20 psi). Each utility must determine its plant's normal steam generator ΔP. The elevation change pressure drop between the RCS pressure measurement location and the top of the steam generator tubes (typically 10 psi) should also be included. This results in a pressure drop of 30 psi for the sample plant.

8. <u>Any Other Factors</u>: If there are any other factors which would make the RCP trip setpoint pressure, as indicated by the RCS wide-range pressure instrument, not appropriately reflect saturation conditions in the top of the steam generator, they should be included.

9. Nominal Sample Calculation:

a. Set pressure of chosen steam generator safety valve (step 3 above) 1085 psig

b. Other factors:
   - i) 3 percent accumulation pressure (step 4 above) 33 psig
   - ii) Steamline ΔP (step 5 above) 1 psig
   - iii) Primary-to-secondary ΔP (step 6 above) 27 psig
   - iv) RCS wide-range pressure instrument to top of steam generator tube ΔP (step 7 above) 30 psig
   - v) Other factors (step 8 above)
   - vi) TOTAL 91 psig

c. RCP trip pressure for sample plant: 1176 psig.

10. Wide-Range RCS Pressure Indication Uncertainty: To the 1176 psig from step 9.c, the uncertainty in the wide-range pressure indication should be added. The normal instrument uncertainty should be used to determine the RCP trip setpoint for normal containment conditions, and the instrument uncertainty based on post-accident containment conditions should be used to determine the setpoint for adverse containment conditions.

    The instrument uncertainties are plant specific and must be calculated by each utility for its respective plant. The instrument uncertainties have been determined for the sample plant, but the values are only applicable for the sample plant and are not intended to represent recommended values for use at other plants. For the sample plant, the instrument uncertainty for the RCS wide-range pressure measurement is 90 psi for normal containment conditions and 390 psi for adverse containment conditions. These values result in RCP trip setpoints of 1266 psig for normal containment conditions and 1566 psig for adverse containment conditions for the sample plant.

4.4.4 Applicability of RCP Trip Criteria

The RCP trip criteria discussed in section 4.4.3 have been developed from a set of analyses and evaluations to address the need for an RCP trip during a small LOCA and to reduce the likelihood of an RCP trip for SGTR and non-LOCA events. The conditions where the RCP trip criteria apply are:

- Following a reactor trip and safety injection actuation initiated from power operation, and
- During recovery actions or at hot standby conditions, before initiation of an operator-controlled RCS cooldown.

The conditions where the RCP trip criteria do not apply are:

- Following a safety injection actuation initiated from cold shutdown, hot shutdown, or startup conditions (refueling is not considered in the context of applicability),
- During recovery actions or at hot standby conditions, following initiation of an operator-controlled RCS cooldown,
- Following any RCP restart specified in emergency operating procedure recovery instructions, and
- When the emergency operating procedures specifically state that the RCP trip criteria do not apply.

In general, the RCP trip criteria do not apply after an operator-controlled RCS cooldown has been initiated. When an operator-controlled cooldown has been initiated, sufficient time after the reactor trip should have ellapsed such that any subsequent failure, beyond that causing the reactor trip, should not require an RCP trip in order to ensure acceptable clad temperatures, even if it is a small LOCA of critical size. This is due to the reduction in decay heat generation with time and because the RCS cooldown will result in less time to cold-leg accumulator injection for a small LOCA. Therefore, if an operator-controlled RCS cooldown results in reaching the RCP trip criteria, the RCPs should not be tripped.

In summary, the emergency operating procedures provide multiple levels of contingency actions that are symptom-based and function-related. In addition to the RCP trip parameter and setpoint, vessel level indicated by the reactor vessel level indication system (RVLIS) and temperatures from the core-exit thermocouples are used to direct operator action if a critical safety function is challenged. The operator is thus provided with actions to maintain critical safety functions that are dependent only on parameters available in the control room and that are independent of the specific event sequence. If the RCP trip criteria step is missed by the operator and conditions degrade to the point where core cooling may be challenged if RCPs are stopped, then the operator is provided with appropriate contingency actions.

TABLE 4.4-1   Limiting Results of SGTR and Non-LOCA Analysis

PLANTS	MINIMUM RCS PRESSURE (psig)	MINIMUM RCS SUBCOOLING (°F)	MINIMUM RCS/SECONDARY DIFFERENTIAL PRESSURE (psi)
Vogtle 1 and 2 Seabrook 1 and 2 Millstone 3 Callaway 1 Wolf Creek 1	1738	58	685
Byron 1 and 2 Braidwood 1 and 2 McGuire 1 and 2 Catawba 1 and 2 Marble Hill 1 and 2 Watts Bar 1 and 2 Comanche Peak 1 and 2	1683	57	669
Trojan 1	1511	52	535
Zion 1 and 2	1482	61	604
Diablo Canyon 2 Salem 1 and 2 Sequoyah 1 and 2	1458	57	564
Cook 1 and 2 Diablo Canyon 1	1428	55	542
South Texas 1 and 2	1544	40	453

TABLE 4.4-1　Limiting Results of SGTR and Non-LOCA Analysis (cont'd)

PLANTS	MINIMUM RCS PRESSURE (psig)	MINIMUM RCS SUBCOOLING (°F)	MINIMUM. RCS/SECONDARY DIFFERENTIAL PRESSURE (psi)
Indian Point 2	1175	31	293
Indian Point 3	1196	32	315
Virgil Summer Shearon Harris 1 and 2	1421	51	549
Farley 1 and 2 North Anna 1 and 2 Surry 1 and 2 Beaver Valley 1	1219	37	350
Beaver Valley 2	1132	30	278
Robinson 2 Turkey Point 3 and 4	1232	31	309
Prairie Island 1 and 2	1348	39	389
Kewaunee	1238	38	361
Ginna Point Beach 1 and 2	1166	29	305
Connecticut Yankee San Onofre Yankee Rowe	Results were not obtained for these plants		

TABLE 4.4-2 Evaluation of RCP Trip Parameter Discrimination Capability for Sample Plant*

	RCP TRIP CRITERIA		
ITEMS EVALUATED	RCS Pressure	RCS Subcooling	RCS/Secondary ΔP
Minimum values for SGTR and non-LOCA transients	1219 psig	37 °F	350psi
SBLOCA - RCP trip setpoint with normal containment conditions	1266 psig	17 °F	157 psi
Does criterion meet discrimination requirement in NRC letters 83-10c and 10d	No	Yes	Yes
SBLOCA - RCP trip setpoint with adverse containment conditions	1566 psig	59 °F	451 psi

*Sample plant: 3-loop plant with high pressure SI system, type 51 steam generators (tube I.D. = 0.775 inches), and no-load T_{avg} = 547 °F.

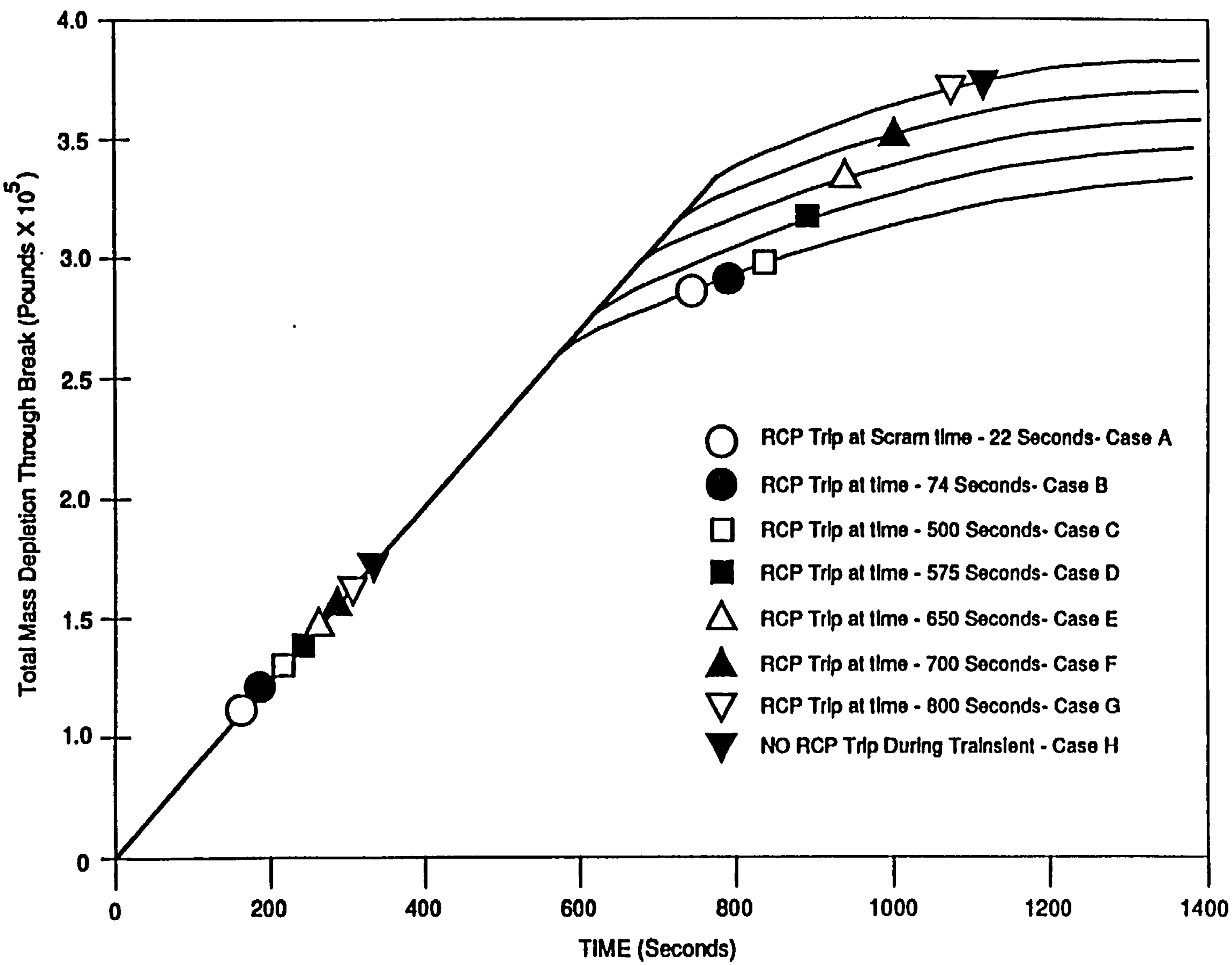


Figure 4.4-1 3-Loop Design 3-in. Diameter Cold-Leg Break

0591

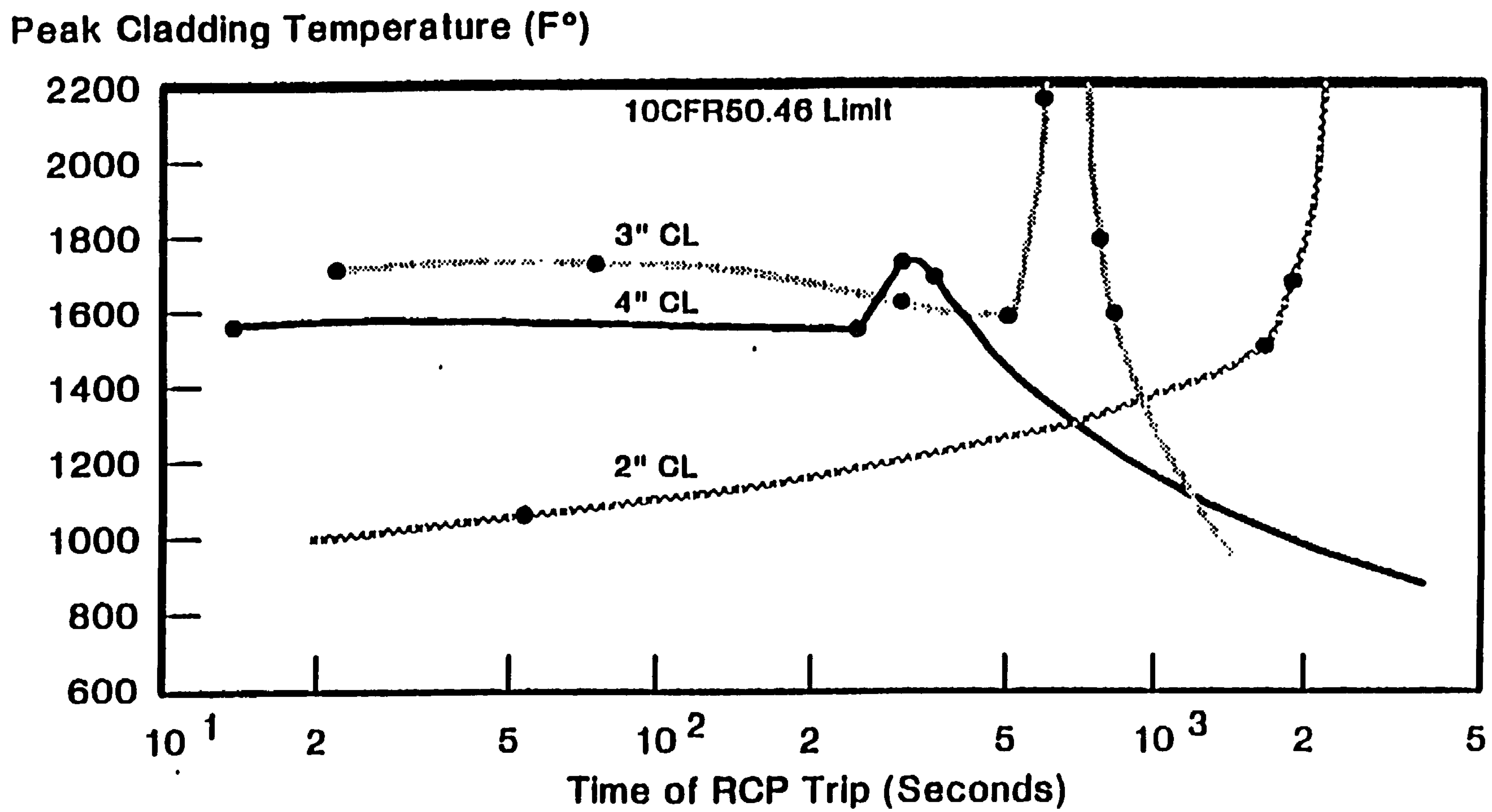


Figure 4.4-2 Effect of RCP Trip on Peak Cladding Temperature for Westinghouse 3-Loop Plant

Westinghouse Technology Advanced Manual

Section 4.5

Steam Generator Tube Problems and In-Service Inspection

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

4.5 STEAM GENERATOR TUBE DEGRADATION AND INSERVICE INSPECTION

Learning Objectives:

1. Describe the following types of steam generator tube degradation and their effects on the tubes:

   a. Denting
   b. Fretting
   c. Pitting
   d. Wastage
   e. Intergranular attack
   f. Stress corrosion cracking

2. Define the following terms:

   a. Degraded tube
   b. Defective tube
   c. Repair limit

3. Discuss the following types of steam generator repairs and when they are used:

   a. Tube plugging
   b. Tube sleeving
   c. Steam generator replacement

4.5.1 Introduction

Steam generator tubes in pressurized water reactor (PWR) plants have exhibited a variety of tube degradation mechanisms as a result of corrosion, mechanical conditions, or both. Corrosion and mechanically induced damage are caused by complex interactions of water chemistry, thermal-hydraulic design, materials selection, fabrication methods, and operating conditions. Various types of corrosion have affected steam generator tubes fabricated from mill-annealed alloy 600, resulting in scheduled and unscheduled outages for steam generator repair and replacement. In addition to interfering with plant availability, these repairs and replacements have increased occupational radiation exposure.

The primary safety goal for steam generator tubes is that they retain adequate structural and leakage integrity over the full range of normal operating, transient, and postulated accident conditions. To ensure that each plant can be operated safely, the plant technical specifications (1) place limits on primary and secondary system activity and on primary-to-secondary leakage, (2) contain requirements to periodically perform inservice inspections of the steam generator tubes (typically with eddy current testing [ECT] methods), and (3) dictate the extent of tube degradation for which tube repair is required. Two tube repair techniques are authorized: tube plugging and tube sleeving (if the NRC has approved tube sleeving for a particular plant's steam generators).

All commercially operating Westinghouse-designed steam generators are vertical shell recirculation-type units. Early-generation steam generators have feed rings above the tops of the tubes, while some later-generation steam generators have lower-entry feed nozzles and preheater sections in the tube bundle regions. Figure 4.5-1 shows a typical Westinghouse steam generator. The use of drilled tube support plates, shown in Figure 4.5-2, in early-generation Westinghouse steam generators is significant because several forms of degradation occur in the annular spaces between the steam generator tubes and the drilled support plates. Newer steam generators have tube support plates of different designs (e.g., broached-hole or lattice-grid support plates) and different materials of construction (e.g., stainless steel), which limit the potential for these forms of degradation to occur.

All currently operating Westinghouse steam generators contain tubing manufactured from a nickel-based alloy (alloy 600 or alloy 690). All of the originally installed steam generators have or had tubing manufactured from alloy 600, whereas some of the later (i.e., beginning in the late 1980s) replacement steam generators have tubes manufactured from alloy 690 (e.g., D. C. Cook Unit 2, Indian Point Unit 3, V. C. Summer, and North Anna Units 1 and 2). A key distinction between steam generators with alloy 600 tubes is in the type of heat treatment that the tubes have received. In general, the older Westinghouse steam generators (models 27, 44, 51, D2, D3, D4, D5, and E) have mill-annealed alloy 600 tubes, whereas the newer Westinghouse steam generators (models F and delta-75 and the replacement steam generators) have thermally treated tubing. (Note that Callaway has model F steam generators with both mill-annealed and thermally treated tubes.) To date, steam generators with thermally treated tubing have exhibited very little or no corrosion-related damage.

4.5.2 Types of Steam Generator Tube Degradation

The primary modes of steam generator tube degradation that have been observed are defined in the following paragraphs and illustrated in Figure 4.5-3. The term "degradation" refers to any chemical or mechanical mechanism affecting a tube's integrity. As noted above, the corrosion-related degradation mechanisms primarily have affected steam generators with mill-annealed alloy 600 tubes.

4.5.2.1 Wastage

Wastage is the localized secondary-side corrosion of alloy 600 tubes caused by chemical attack from acid phosphate residues concentrated in low flow areas.

Degradation experience at Westinghouse units before the mid-1970s included wastage (localized thinning of tube walls) and caustic stress corrosion cracking (SCC) on the secondary sides of tubes. The major method of controlling the secondary water chemistry during this period was coordinated phosphate control. The early problems of wastage and SCC have been attributed to difficulties in adequately controlling phosphate concentrations and to impurities carried into the steam generators by feedwater. The adoption of all-volatile treatment (AVT) control in the mid-1970s succeeded in arresting any further significant wastage by phosphates. All operating units in the U.S. currently operate with AVT water chemistry control.

4.5.2.2 Denting

Denting is the plastic deformation (constriction) of steam generator tubes; it typically occurs when tube support structures (e.g., carbon steel tube support plates) corrode. Such corrosion results in the buildup of corrosion products (typically magnetite) in the crevices between tubes and tube support plates. This buildup of magnetite (iron oxide) leads directly to the mechanical deformation of tubes where they pass through the tube support plates; when the buildup is extensive, denting can lead to the deformation and cracking of the tube support plates themselves.

Denting was first identified in 1975, when a number of plants which had shifted from phosphate water chemistry control to AVT control began to develop anomalous ECT signals at the tube support plates. Subsequently, steam generators which had never operated with phosphate water chemistry developed dents.

Many Westinghouse steam generators have exhibited denting. In the mid-to-late 1970s, excessive denting of tubes near tube support plates resulted in (1) primary-to-secondary leaks as a consequence of SCC which initiated primarily from the inside (primary-side) surfaces of dented tubes, (2) cracking of tube support plates, and (3) the inability to pass standard-size inspection probes through tubes. In some instances, steam generators were replaced as a result of extensive denting. Steam generators with carbon steel support plates are potentially susceptible to denting if sufficient condenser in-leakage occurs, because denting is caused by the formation and concentration of acid chlorides in the crevices between tubes and tube support plates. Because copper oxide has been demonstrated to act as a catalyst for denting-related corrosion, plants with copper in their secondary systems are even more susceptible.

Denting is presently not a major threat to operating steam generators as a result of improved water chemistry and secondary system improvements. Furthermore, the denting seen in the field today is relatively minor compared to that of the 1970s, in that the extent of tube deformation is much less, and that standard-size probes can typically be passed through dented tubes. The improvements in water chemistry include more restrictive limits on impurity levels. Secondary system improvements include the replacement of copper-bearing components, the replacement of condenser tubes to reduce the potential for leakage, and, in the newer steam generators, the installation of tube support plates (broached-hole and lattice-grid support plates) constructed from stainless steel, a more corrosion-resistant material. The Westinghouse replacement steam generators, the model F steam generators, and some model D and E steam generators contain ferritic stainless steel support plates.

Recent denting has been noted at plants that currently have steam generators with carbon steel support plates, although the denting is minor, as discussed above. Nevertheless, axially and circumferentially oriented SCC continues to occur at dented locations. Axially oriented SCC generally initiates from the inside of a tube, and circumferentially oriented SCC generally initiates from the outside of a tube. In a few instances, circumferentially oriented SCC that has initiated from the inside of a tube has been reported.

4.5.2.3 Pitting

Classical pitting is generally considered to be a localized form of general corrosion resulting from nonuniform corrosion rates caused by the formation of local corrosion cells.

Minor shallow pitting (i.e., an occasional isolated pit) has been seen in several tubes removed from service for destructive examination since the 1970s. This pitting was not detected by ECT methods and was of such a small size that it did not constitute a concern for primary-to-secondary leakage.

Major pitting was first seen at Indian Point Unit 3 in 1981, where more than 1000 tubes were found to be affected. This pitting was readily detected with ECT methods against background signals similar to those observed in laboratory tubes containing surface copper deposits. It was confined to the cold-leg side of the tube bundle and concentrated within a range of 6 to 20 in. above the tubesheet, with decreasing degradation up to 36 in. above the tubesheet.

The unit had been subjected to continuous condenser in-leakage, and an examination of steam generator sludge showed that it contained a high level of copper oxide, which is indicative of severe oxygen ingress through the condenser. The pitting at Indian Point Unit 3 resulted in an extensive campaign to insert sleeves in the pitted tubes. In addition, the pitting contributed to the decision to replace the Indian Point Unit 3 steam generators in 1989.

With improved water chemistry control and design changes in secondary systems (e.g., replacement of copper-bearing components and installation of titanium-tubed main condensers), pitting of steam generator tubes is not a major concern for PWR owners at present.

4.5.2.4 Fretting

Fretting is the loss of tube material caused by excessive rubbing of a tube against a support structure. Fretting can be caused by either primary-side or secondary-side flow-induced vibration of the tubes.

In the mid-1970s, tubes in early-generation Westinghouse steam generators at San Onofre Unit 1 and Haddam Neck experienced fretting (wear) near the anti-vibration bar (AVB) supports located in the U-bend regions of the tube bundles. This problem was corrected with the installation of additional AVBs of a revised design. The revised AVB design employs chromium-plated Inconel bars with square cross sections that increase the area of contact and reduce the clearances between the bars and the tubes. The original AVB design included round carbon steel bars. The improved AVB design has been incorporated into later-generation Westinghouse steam generators to address the problem of high wear rates at AVBs affecting a significant number of tubes.

Tube fretting continues to occur near support structures, such as AVBs and tube support plates. To date, AVB wear is the dominant degradation mechanism affecting Westinghouse model F steam generators (e.g., Vogtle, Wolf Creek, and Callaway). Tube wear near tube support plates has also been observed in steam generators at a number of plants. In the early-to-mid-1980s, excessive wear in the preheater sections of steam generators led licensees to expand tubes into the support plates in model D4, D5, and E steam generators and to modify the original impingement plate assemblies in the preheaters of model D2 and D3 steam generators to minimize tube vibration/motion and, hence, to decrease wear at these locations.

4.5.2.5 Intergranular Attack

Intergranular attack (IGA) is the general term denoting the uniform or generally uniform corrosive attack of all grain boundaries over the surface of tubing with no preferential (stress-related) orientation.

Corrosion of steam generator tubes in the crevices between tubes and tubesheets was first identified in 1977 at Point Beach Unit 1. In many early-generation Westinghouse steam generators, the tubes were not expanded over the full depth of the tubesheet, thereby forming crevices between the tubes and the tubesheet, where a concentrated aggressive environment can lead to IGA and to eventual SCC of the alloy 600 tubing. Corrosion (IGA and SCC) in tube-to-tubesheet crevices has occurred in steam generators at a number of plants (Kewaunee, Point Beach Unit 2, Prairie Island Units 1 and 2). This corrosion has necessitated extensive sleeving activities at these plants.

4.5.2.6 Stress Corrosion Cracking

Intergranular stress corrosion cracking (IGSCC) of stressed tubes, without reference to a causative chemical agent, is a term used either to encompass a number of known IGSCC mechanisms or to indicate that the chemical causing the corrosion is unknown. IGSCC generally consists of one or more major cracks with minor to moderate amounts of branching. These cracks can be either axially or circumferentially oriented (or both) and are sometimes associated with IGA. A combination of axially and circumferentially oriented IGSCC at the same location on a tube is sometimes referred to as "mixed-mode" cracking. Throughout this section, the term "SCC" denotes IGSCC.

Caustic stress corrosion cracking (CSCC) is the term used when the specific SCC causative agent has been identified as a caustic material.

Primary water stress corrosion cracking (PWSCC) is the term used to identify SCC that initiates from the primary side (inside) of steam generator tubes. The causative agent for this type of corrosion is unspecified.

Outside diameter stress corrosion cracking (ODSCC) is the term used to identify SCC on the secondary side (outside) of steam generator tubes. When this term is used, the specific causative agent is either unspecified or unknown (i.e., bulk water chemistry analysis does not indicate the presence of free caustic, so the corrosion mechanism cannot be identified as CSCC).

SCC is the dominant degradation mechanism affecting steam generator tubes in the U.S. today.

Axially oriented SCC has been detected at several locations on steam generator tubes: at the expansion transitions, in tube-to-tubesheet crevices (in steam generators with partial-depth-expanded tubes), in sludge piles, where tubes pass through tube support plates, in the U-bend portions of tubes (tubes with small-radius U-bends), and in tube freespans.

The small-radius U-bends in the first two rows of tubing in several models of Westinghouse steam generators (e.g., models 51 and D) have exhibited PWSCC. These cracks have been found either at the apexes of the U-bends or at the transitions between the U-bends and the straight-span portions of the tubing. In 1976, PWSCC at the U-bend apex caused an axially oriented tube rupture in one of the original Surry Unit 2 steam generators, with a resulting primary-to-secondary leak rate of 330 gpm. The high stress in the U-bend of the cracked tube resulted from tube support plate deformation caused by denting. Due in part to difficulties in inspecting this region with conventional (bobbin coil) ECT methods in the 1970s and early 1980s, several utilities plugged all the tubes in row 1 of their steam generators as a preventive measure. With the development of a technique to heat treat the tubes in this region to reduce the residual stresses, some utilities have heat treated the small-radius U-bend portions of tubes in rows 1 and 2 to provide resistance to SCC at these locations. As a result of applying this heat-treatment technique, some utilities have recovered tubes that had been preventively plugged, thereby allowing them to be returned to service following satisfactory ECT inspections of the entire tubes.

Another category of U-bend cracks is SCC in the transition areas between the U-bends and straight portions of tubing. These cracks have generally been observed at plants which have not experienced denting. This tangent-point cracking phenomenon has been responsible for numerous small leaks affecting Westinghouse model 51 steam generators, although this mechanism is not prevalent today.

Predominantly axially oriented ODSCC has been observed at the tube support plate elevations of Westinghouse steam generators with drilled-hole carbon steel support plates. This mechanism has had a significant economic impact on the nuclear industry and contributed to the decisions to permanently shut down the Trojan nuclear plant and to replace the steam generators at a number of plants (e.g., Braidwood Unit 1, Byron Unit 1, and Catawba Unit 1). This phenomenon has affected primarily model 51 and D steam generators, which have mill-annealed alloy 600 tubes. Due in part to the complex nature of this form of degradation, tube-repair criteria based on ECT voltage indications (rather than length-based or depth-based repair criteria) have been developed for licensees to use, subject to NRC review and approval, in evaluating the structural and leakage integrity of affected tubes, as discussed in Generic Letter 95-05, "Voltage-Based Repair Criteria for Westinghouse Steam Generator Tubes Affected by Outside Diameter Stress Corrosion Cracking."

Axially oriented ODSCC has also been detected in the freespan regions of tubes at various elevations. This mechanism has affected the steam generators at only a few plants to date (e.g., McGuire Units 1 and 2, Farley Unit 1, and Point Beach Unit 2). In the case of McGuire Unit 1, freespan ODSCC on the cold-leg side of one steam generator resulted in a tube rupture in 1989. The freespan cracking at Point Beach Unit 2 and Farley Unit 1 was located in the hot-leg portions of the steam generators and, to date, has only affected a few tubes.

Circumferentially oriented SCC has been noted at expansion transitions (full-depth hard-roll transitions, Westinghouse explosive [WEXTEX] transitions, and hydraulic transitions), in the small-radius U-bend portions of tubes (rows 1 and 2), at dented locations (primarily tube support plate intersections where the tubes are dented; these are commonly referred to as dented tube support plate intersections), and in parent tubes at sleeve joints. Circumferential cracking is the subject of Generic Letter 95-03, "Circumferential Cracking of Steam Generator Tubes."

Circumferentially oriented inside- and outside-diameter SCC at tube expansion transitions is currently a major issue for the industry, due in part to the inability to accurately determine the size of this form of degradation. This problem has led to the practice of plugging or repairing tubes with circumferential indications upon detection. Extensive outside-diameter-initiated circumferential cracking was observed at Byron Unit 1 in 1995, resulting in the repair of approximately 2500 tubes by sleeving, and in 1996, when approximately 3500 tubes were found to have circumferential indications. The licensee for Byron Unit 1 removed 10 tubes for destructive examination in 1995 to characterize the nature of the degradation and to assess inspection capabilities. These tests indicated that the circumferential indications were attributed to small circumferential cracks that were not coplanar and were separated by ligaments of sound material. The extent of the circumferential cracking ranged up to 360 degrees of the tube circumference.

A small number of circumferentially oriented indications have also been detected in small-radius U-bend portions of tubes. This degradation mechanism is primarily limited to Westinghouse model 51 and D steam generators.

Circumferential SCC at dented tube support plate intersections has been detected at a few plants. This cracking has generally initiated from the outside diameters of tubes, and only a limited number of tubes has been affected. In the early-to-mid-1990s, such circumferential indications were detected by eddy current examination at Sequoyah Unit 1, North Anna Units 1 and 2 (original steam generators), Salem Unit 1, and Diablo Canyon Unit 1. Destructive examination of tubes removed from the North Anna and Diablo Canyon Unit 1 steam generators confirmed the nature of the indications as circumferential SCC.

Circumferential indications have also been detected in the parent tubes associated with sleeve joints. These indications have been detected most often in tubes with Westinghouse hybrid expansion joint (HEJ) sleeves (circumferential SCC initiating from the inside diameters of the parent tubes with a segmented noncoplanar morphology), but have also been detected in tubes with Babcock & Wilcox (B&W) kinetically welded sleeves (circumferential PWSCC) and in tubes with Combustion Engineering (CE) tungsten inert gas (TIG) welded sleeves (fabrication-induced circumferential and volumetric defects that were not attributable to SCC). These types of sleeves are further described in Section 4.5.3.3.

As a preventive measure, tubes with B&W kinetically welded sleeves have been removed from service at several plants by plugging the tubes. This action was taken as a result of the PWSCC phenomenon that resulted in a tube leak at McGuire Unit 1 (Information Notice 94-05, "Potential Failure of Steam Generator Tubes with Kinetically Welded Sleeves"). As of 1996, only one plant, Arkansas Nuclear One Unit 2, has steam generator tubes with B&W kinetically welded sleeves in service. A number of plants have Westinghouse hybrid expansion joint sleeves installed (Kewaunee, Point Beach Unit 2, and D. C. Cook Unit 1), and a number of plants have CE TIG welded sleeves installed (Byron Unit 1, Prairie Island Unit 1, and Zion Units 1 and 2).

Table 4.5-1 lists the more recent steam generator tube leaks which have occurred at Westinghouse-designed plants.

4.5.3 Steam Generator Inservice Inspections

The program for inservice inspection of steam generator tubes, as presented in earlier versions of the Westinghouse Standard Technical Specifications, is a modification of Regulatory Guide 1.83, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes." It is a program designed to provide more extensive inspection of steam generators with evidence of tube degradation. Table 4.5-2, which is similar to tables appearing in many plants' technical specifications, outlines the inspection requirements. A degraded tube has a wall thickness reduced in excess of 20% but less than the plugging/repair limit (typically 40%). Historically, the plugging/repair limit has been a depth-based limit that bounds the amount of degradation that a tube can have when it is returned to service following an inspection. A tube with an imperfection that exceeds the technical specification plugging/repair limit is considered to be a defective tube. The terms "plugging limit" and "repair limit" tend to be used interchangeably; however, "repair limit" is more suitably used for those plants where tube sleeving is authorized by the NRC.

The NRC has approved modified versions of the inservice inspection program provided by the Westinghouse Standard Technical Specifications. These versions treat tubes in areas of unique operating conditions or physical construction separately from the randomly selected tube samples. Inspection of these tubes is not considered to be part of the required three percent random inspection, and the results of the inspection of these tubes are not used in classifying the random inspection results into the C-1, C-2, or C-3 categories (these categories are defined in Table 4.5-2). This form of inspection therefore distinguishes between random and deterministic forms of degradation.

At present, technical specifications for nuclear power plants require that inservice inspections be performed every 12 to 40 months, depending on the conditions of the steam generator tubes. In cases where the degradation processes are highly active, inspections are performed at even more frequent intervals (typically referred to as mid-cycle inspections). Requirements for plants committed to customized technical specifications may vary from those described in this section.

4.5.3.1 Technical Specification Bases

The surveillance requirements for the inspection of steam generator tubes ensure that the structural and leakage integrity of this portion of the reactor coolant system is maintained. Inservice inspection of steam generator tubing is essential in order to maintain surveillance of the conditions of the tubes in the event that there is evidence of mechanical damage or progressive degradation due to design, manufacturing errors, or inservice conditions that lead to corrosion. Inservice inspection of steam generator tubing also provides a means of characterizing the nature and cause of any tube degradation so that corrective measures can be taken.

To ensure that steam generator tubes retain sufficient integrity for continued operation, unscheduled inservice inspections are performed on each steam generator following (1) primary-to-secondary tube leaks, (2) a seismic event greater than the operating basis earthquake, (3) a loss of coolant accident requiring actuation of the engineered safety features, which for this specification is defined as a break greater than that equivalent to the severance of a one-in. (inside diameter) pipe, and (4) a main steam line or feed line break greater than that equivalent to a steam generator safety valve failing open. Transients less severe than those listed above do not require inspections because the resulting stresses are well within the stress criteria established by Regulatory Guide 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes," that inservice steam generator tubes must be capable of withstanding.

A plant is expected to be operated so that the secondary coolant will be maintained within those chemistry limits found to result in negligible corrosion of the steam generator tubes. If the secondary-coolant chemistry is not maintained within these limits, increased degradation of steam generator tubes may occur.

To address the potential for tube dgradation to develop and grow at higher rates than expected, limits are set on primary-to-secondary leakage. Technical specifications typically have a primary-to-secondary leakage limit of 500 gpd per steam generator. For plants with extensive steam generator tube degradation, lower leakage limits have been adopted either administratively or in the technical specifications. These limits range from 50 gpd to 150 gpd per steam generator (e.g., plants that conform to the guidance of Generic Letter 95-05 implement a 150-gpd limit).

Leakage in excess of the technical specification limit requires a plant shutdown and an unscheduled inspection, during which the leaking tube(s) are located and plugged or repaired. The primary-to-secondary leakage limit is a defense-in-depth measure that gives added confidence that, should a tube leak, the plant will be shut down in a timely manner.

Tube degradation is typically found during scheduled inservice examinations of steam generator tubes. Tube repair (plugging or sleeving) is required for all tubes with imperfections exceeding the tube repair limits. Various tube repair limits have been approved; however, all plants have a depth-based limit that is applicable to all forms of degradation. Alternatives to this depth-based limit have been approved on a plant-specific basis; such alternatives include the voltage-based repair limits for tubes with ODSCC at drilled-hole tube support plate elevations in specific Westinghouse steam generators. The depth-based limit varies from plant to plant but is typically 40% of the tube wall thickness (i.e., tubes with imperfection depths greater than or equal to 40% of the tube wall thickness must be plugged or repaired).

4.5.3.2 Eddy Current Testing

Eddy current testing is the primary means for inspecting tubes. This inspection method involves inserting a test coil inside the tube and pushing and pulling the coil so that it traverses the entire tube length. The test coil is then excited by alternating current, which creates a magnetic field that induces eddy currents in the tube wall. Disturbances of the eddy currents caused by flaws in the tube wall produce corresponding changes in the electrical impedance measured at the test coil terminals. Instrumentation translates these changes in test coil impedance into output voltages which can be monitored by the data analyst. The depths of certain types of flaws can be determined by the observed phase angle responses. The test equipment is calibrated using tube specimens containing artificially induced flaws of known depths.

Geometric discontinuities, such as expansion transitions and dents, and support structures, such as the tubesheet and tube support plates, also produce eddy current signals, making it very difficult to discriminate defect signals at these locations. Very small volume flaws, such as IGA, SCC, fatigue cracks, and small pits, traditionally have been hard to detect with single-frequency ECT methods. The use of multifrequency techniques, whereby the test coil is excited at multiple frequencies rather than at a single frequency (introduced in the mid-1980s), and the use of specialized nonstandard probes have improved detection capabilities in this regard, although further improvements are warranted and are being pursued.

Inspections of steam generator tubes generally employ both a bobbin coil probe and an additional probe or probes, such as a rotating probe, a Cecco probe, or both. The bobbin coil establishes a magnetic field oriented along the tube's axis and sets up eddy currents in the circumferential direction. This type of coil is thus quite sensitive to axially oriented flaws. The bobbin coil probe enables a rapid screening of a tube for degradation; it can be pulled through a tube at speeds in excess of 48 in. per second. The bobbin coil, however, has several limitations: (1) a general inability to permit characterization of the degradation (e.g., axial, circumferential, or volumetric; single or multiple axial indications; etc.), (2) an inability to detect circumferentially oriented degradation (the bobbin coil is relatively insensitive to circumferentially oriented tube degradation), and (3) a limited capability to detect degradation in regions with geometric discontinuities (e.g., expansion transitions, U-bends, and dents) or deposits. These limitations have led to the use of other probes, such as rotating probes and Cecco probes.

A rotating probe generally has one to three specialized test coils. These test coils usually include at least a pancake coil that is sensitive to both axially and circumferentially oriented degradation. The pancake coil is a smaller probe which establishes a magnetic field perpendicular to the tube surface and sets up eddy currents parallel to the tube surface. The pancake coil is thus effective in identifying cracks of any orientation. Other test coils mounted on the rotating probe head are an axially wound coil (which is sensitive to circumferentially oriented degradation), a circumferentially wound coil (which is sensitive to axially oriented degradation), and a plus point coil (which reduces volumetric influences and is sensitive to both axially and circumferentially oriented degradation). Each of these test coils can be driven at specific frequencies to ensure an optimal inspection of the tubing. In general, lower frequencies are better for detecting degradation initiating from the outside diameter of a tube, and higher frequencies are better for detecting degradation initiating from the inside diameter of a tube. The advantages of the rotating probes are that they are sensitive to circumferentially oriented degradation (a major disadvantage of the bobbin coil probe), that they can produce better characterizations of defects, and that they are less sensitive to geometric discontinuities. The major disadvantage of the rotating probes is their slow inspection speed (typically less than one in. per second). Because of these slow inspection speeds, a rotating probe is only used at specific locations (e.g., U-bends, sleeves, expansion transitions, dents, locations where there are bobbin coil indications, and locations where more sensitive inspections are needed).

Cecco probes operate differently from rotating probes. A Cecco probe contains an array of transmitting and receiving pancake coils, rather than a single combined transmit/receive coil which is rotated inside the tube; the Cecco probe is not rotated as it is pulled through the tube. Like the rotating probes, Cecco probes are sensitive to circumferentially oriented degradation; however, characterization of degradation with these probes is currently limited. The major advantage of the Cecco probe is its much faster inspection speed (12 to 15 in. per second) than that of the rotating probes.

The various types of eddy current probes are pictured in Figures 4.5-4, 4.5-5, and 4.5-6.

Inspections of steam generator tubes at operating plants have demonstrated the capability to reliably detect certain forms of degradation that have penetrated deeper than 20% of the original tube wall thickness (e.g., tube wear and wastage). However, the reliable detection of other forms of degradation (e.g., SCC) continues to be an issue. Nonetheless, with properly qualified techniques, procedures, and analysts, and with appropriate restrictions on operating parameters, SCC can be detected before tube structural and leakage integrity is significantly impaired. For those forms of degradation (e.g., SCC) that cannot be reliably depth sized, plugging of the affected tube is typically performed upon detection of the degradation.

As discussed above, even though ECT probes have limitations, flaws of structural significance are generally detectable when properly qualified probes and techniques are used. In addition, with a knowledge of the limitations of the techniques employed and appropriate restrictions on operating parameters (e.g., hot-leg temperature, water chemistry, and operating interval duration), tube integrity can be ensured. The primary-to-secondary leakage rate limits in the plant technical specifications provide added assurance that if a tube leaks, the unit will be shut down in a timely manner for the appropriate corrective action. If necessary, preventive repairs (see Section 4.5.3.3), more restrictive limits on primary-to-secondary leakage, hydrostatic testing of the tube bundle, in situ pressure testing of tubes with crack indications, and corrective measures to slow the rate of further corrosion are additional steps which can be taken to ensure safe operation.

4.5.3.3 Steam Generator Repairs

Technical specifications provide limits for the maximum allowable percentage of wall degradation beyond which degraded tubes must be removed from service by plugging or repaired by sleeving. The plugging/repair limits are based on the minimum tube wall thickness necessary to provide adequate structural margins (in accordance with Regulatory Guide 1.121) during normal operating and postulated accident conditions. These limits allow for eddy current testing errors and for incremental wall degradation that might occur prior to the next inservice inspection of steam generator tubes. These plugging/repair limits are conservatively based according to an assumed mode of degradation, through which a tube wall is uniformly thinned over a significant axial distance. These limits do not consider additional structural margins associated with defects that create small-volume thinning, such as pitting, nor do they consider the external structural constraints against gross tube failures provided by tubesheets and tube support plates. Therefore, a depth-based limit tends to be inappropriate for such highly localized flaws as stress corrosion cracks and flaws at elevations below the top of the tubesheet. As a result, the nuclear industry has developed, and the NRC has approved, various alternate repair criteria for specific forms of tube degradation (e.g., the Generic Letter 95-05 voltage-based limits for predominantly axially oriented ODSCC at tube support plate elevations and the F-star limits for degradation confined within the tubesheet below the tube expansion transitions). This approach to addressing tube integrity is referred to as "degradation-specific" management.

In the 1970s, operating experience demonstrated that additional plugging/repair criteria are necessary to address tube denting. Tubes are susceptible to SCC at the dent locations; the extent of degradation is dependent on stress level, strain rate, time, and material properties. Tests have shown that dented tubes with small through-wall cracks near support plates have adequate margins to prevent bursting or collapsing during normal operating and postulated accident conditions. Severe SCC could, however, reduce the margins to unacceptable levels. The objective of the plugging criteria for dented tubes adopted during the 1970s was to remove from service any tubes which could develop through-wall cracks or that could become severely degraded before the next steam generator inspection. These criteria were plant-specific and were generally based on operating experience that included the maximum-size eddy current probe which could be passed through a dented location. For plants with especially high rates of denting, additional plugging criteria were established based on the rate of denting and the interval of time before the next inspection.

As mentioned above, improved water chemistry and better steam generator design have limited recent denting and the growth of existing dents. Also, many steam generators with large numbers of severely dented tubes have been replaced. As a result, large dents (i.e., those that restrict the passage of a normal-size bobbin probe) remain prevalent only in the steam generators at Indian Point Unit 2 and Haddam Neck, and the plant-specific plugging criteria which address denting remain in effect only for those plants.

Plugging

The plugging technique involves the installation of plugs at the inlet and outlet of a defective tube. After plugging, the tube no longer functions as the boundary between the primary and secondary coolant systems. A typical mechanically expanded tube plug is shown in Figure 4.5-7.

Sleeving

To prolong the life of severely degraded steam generator tubes, some utilities, with prior NRC approval, have repaired defective tubes by sleeving. After sleeving, a repaired tube may remain in service.

The tube sleeving procedure involves inserting a tube of smaller diameter and length (a sleeve) inside the tube to be repaired (see Figure 4.5-8). The sleeve is positioned to span the degraded portion of the original tube (i.e., the parent tube), and the ends of the sleeve are secured to the parent tube, forming a new pressure boundary and structural element between the attachment points.

Sleeves vary in length and may be attached to the parent tubes in a variety of ways. As a result, a variety of sleeve designs exists. The name for a particular sleeve type typically reflects the method by which the sleeve is secured to the parent tube. Historically, a sleeve was either hydraulically, mechanically, or explosively expanded above and below the degraded tube region. For example, installation of a Westinghouse HEJ sleeve involves initially expanding the sleeve into the parent tube by hydraulic means and then hardroll expanding a portion of this hydraulically expanded region of the sleeve/tube configuration (this process is used only for the upper joint of the sleeve). Installation of a B&W kinetically welded sleeve involves expanding the sleeve into the tube by detonating a kinetic weld device. Installation of a CE TIG welded sleeve involves initially expanding a portion of the sleeve into the tube hydraulically and then TIG welding the sleeve and tube together at this location (i.e., within the hydraulically expanded region). Currently, a typical sleeve is hydraulically expanded into its parent tube and then welded (laser or TIG welded) to ensure additional leakage integrity. Sleeves made from alloys 600 and 690 have been used throughout the industry. Currently, the material of choice for sleeves is alloy 690.

Sleeving repairs to restore primary coolant boundary integrity have been performed on the straight portions of tubing degraded by such mechanisms as wastage, IGA, and SCC. Severely dented locations have not been sleeved.

Degradation at sleeve joints has been observed at a number of plants. This degradation is normally associated with the parent tube rather than with the sleeve itself. The parent tubes of some Westinghouse HEJ sleeves and B&W kinetically welded sleeves have exhibited service-induced SCC at the sleeve joints (as discussed in

Section 4.5.2.6). Extensive cracking in Westinghouse HEJ sleeves was first identified at Kewaunee in 1994. Significant cracking of B&W kinetically expanded sleeves was first identified at McGuire Unit 1 in 1993. Fabrication-induced sleeve joint degradation has also been observed in CE TIG welded sleeves (also discussed in Section 4.5.2.6). This volumetric (weld suckback) and circumferential (weld inclusion) degradation has been attributed to inadequate tube cleaning before sleeve insertion.

Steam Generator Replacement

To avoid the need for derating plants and the extensive downtimes required for steam generator inspections, some utilities have either replaced severely degraded steam generators or are considering their replacement. The decision to replace a steam generator is made largely for economic, rather than technical, reasons. Rather than replace their original steam generators, some utilities have chosen to operate with their original steam generators until it is no longer economically viable to operate their plants. The duration of an outage for steam generator replacement varies; currently, steam generators can be replaced in two to three months.

A utility must consider the following factors before replacing steam generators: (1) the size of the equipment hatch opening, (2) the vertical clearance within the containment building, and (3) its preference with respect to reactor coolant pipe cut or channel head cut.

To minimize the potential for several modes of tube degradation which have been identified to date, the replacement generators currently being installed include the following improvements:

1. They have type 405 ferritic stainless steel lattice-grid tube support plates to reduce the potential for denting and for the accumulation of deposits which can result in SCC.

2. They have thermally treated alloy 690 tubing, with stress relief of the innermost rows of the tube bundle to reduce the potential for SCC. Thermal treatment involves subjecting the mill-annealed tubes to a final heat treatment for approximately 15 hours, which relieves fabrication stresses and further improves the tubes' microstructure, thus improving their corrosion resistance.

3. Their tubes are hydraulically expanded over the full depth of the tubesheets to eliminate crevices and to reduce the stresses at the expansion transitions.

Plants that have replaced steam generators are listed in Table 4.5-3.

4.5.4 References

1. NUREG-0523, "Summary of Operating Experience with Recirculating Steam Generators," January 1979.

2. NUREG-0886, "Steam Generator Tube Experience," February 1982.

3. NUREG-1063, "Steam Generator Operating Experience, Update for 1982-1983," June 1984.

4. NUREG/CR-5150, "Steam Generator Operating Experience, Update for 1984-1986," June 1988.

5. NUREG/CR-5349, "Steam Generator

Operating Experience, Update for 1987-1988," June 1989.

6. NUREG/CR-5796, "Steam Generator Operating Experience, Update for 1989-1990," December 1991.

7. NUREG/CR-6365, "Steam Generator Tube Failures," April 1996.

8. Bulletin 88-02, "Rapidly Propagating Cracks in Steam Generator Tubes," February 5, 1988.

9. Generic Letter 95-03, "Circumferential Cracking of Steam Generator Tubes," April 28, 1995.

10. Generic Letter 95-05, "Voltage-Based Repair Criteria for Westinghouse Steam Generator Tubes Affected by Outside Diameter Stress Corrosion Cracking," August 3, 1995.

11. Information Notice 88-99, "Detection and Monitoring of Sudden and/or Rapidly Increasing Primary-to-Secondary Leakage," December 20, 1988.

12. Information Notice 90-49, "Stress Corrosion Cracking in PWR Steam Generator Tubes," August 6, 1990.

13. Information Notice 91-43, "Recent Indications Involving Rapid Increases in Primary-to-Secondary Leak Rate," July 5, 1991.

14. Information Notice 91-67, "Problems with the Reliable Detection of Intergranular Attack (IGA) of Steam Generator Tubing," October 21, 1991.

15. Information Notice 92-80, "Operation with Steam Generator Tubes Seriously Degraded," December 7, 1992.

16. Information Notice 93-52, "Draft NUREG-1477, 'Voltage-Based Interim Plugging Criteria for Steam Generator Tubes,'" July 14, 1993.

17. Information Notice 93-56, "Weaknesses in Emergency Operating Procedures Found as a Result of Steam Generator Tube Rupture," July 22, 1993.

18. Information Notice 94-05, "Potential Failure of Steam Generator Tubes Sleeved with Kinetically Welded Sleeves," January 19, 1994.

19. Information Notice 94-43, "Determination of Primary-to-Secondary Leak Rate," June 10, 1994.

20. Information Notice 94-62, "Operational Experience on Steam Generator Tube Leaks and Tube Ruptures," August 30, 1994.

21. Information Notice 94-88, "Inservice Inspection Deficiencies Resulting in Severely Degraded Steam Generator Tubes," December 23, 1994.

22. Information Notice 95-40, "Supplemental Information to Generic Letter 95-03, 'Circumferential Cracking of Steam Generator Tubes,'" September 20, 1995.

23. Information Notice 96-09, "Damage in Foreign Steam Generator Internals," February 12, 1996.

24. Regulatory Guide 1.83, "Inservice Inspection of Pressurized Water Reactor Steam Genera-

tor Tubes," Revision 1, July 1975.

25. Regulatory Guide 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes," August 1976.

TABLE 4.5-1 Recent Westinghouse Steam Generator Tube Leaks

Unit	Date	Failure Mechanism
Zion 2	Mar 94	IGA in tubesheet crevice region
South Texas 1	Mar 94	Leaking plug
McGuire 1	Jan 94	Circumferential PWSCC in parent tube associated with a B&W kinetically welded sleeve
Braidwood 1	Oct 93	Axial ODSCC located in tube freespan between two AVBs
McGuire 1	Aug 93	Circumferential PWSCC in parent tube associated with a B&W kinetically welded sleeve
Kewaunee	Jun 93	Leaking plug
Trojan	Nov 92	Circumferential crack associated with an improperly heat treated B&W kinetically welded sleeve
Prairie Island 1	Mar 92	Axial crack in roll transition region
McGuire 1	Jan 92	Axial ODSCC located in tube freespan

TABLE 4.5-2 Steam Generator Tube Inspection

1ST SAMPLE INSPECTION			2ND SAMPLE INSPECTION		3RD SAMPLE INSPECTION	
Sample Size	Result	Action Required	Result	Action Required	Result	Action Required
A minimum of S Tubes per S.G. **	C-1***	None	N/A	N/A	N/A	N/A
	C-2***	Plug defective tubes and inspect additional 2S tubes in this S.G.	C-1	None	N/A	N/A
			C-2	Plug defective tubes and inspect additional 4S tubes in this S.G.	C-1	None
					C-2	Plug Defective tubes
					C-3	Perform action for C-3 result of first sample
				Perform action for C-3 result of first sample	N/A	N/A
	C-3***	Inspect all tubes in this S.G., plug defective tubes and inspect 2S tubes in each other S.G. Prompt notification to NRC pursuant to specification	All other S.G.'s are C-1	None	N/A	N/A
			Some S.G.'s C-2 but no additional S.G. are C-3	Perform action for C-2 result of second sample	N/A	N/A
			Additional S.G. is C-3	Inspect all tubes in each S.G. and plug defective tubes. Prompt notification to NRC pursuant to specification 6.9.1	N/A	N/A

*Source: Standard Technical Specifications

** S = 3(N/n)% Where N is the number of steam generators in the unit, and n is the number of steam generators inspected during an inspection.

*** C-1: Less than 5% of the total tubes inspected are degraded tubes and none of the inspected tubes are defective.

*** C-2: One or more tubes, but not more than 1% of the total tubes inspected are defective, or between 5% and 10% of the total tubes inspected are degraded tubes.

*** C-3: More than 10% of the total tubes inspected are degraded tubes or more than 1% of the affected tubes are defective

TABLE 4.5-3 Steam Generator Replacements				
Plant Name	No. of Loops	Original SGs	New SGs	Completion Date
Surry 2	3	W/51	W/51F	Sep 80
Surry 1	3	W/51	W/51F	Jul 81
Turkey Point 3	3	W/44	W/44F	Apr 82
Turkey Point 4	3	W/44	W/44F	May 83
Point Beach 1	2	W/44	W/44F	Mar 84
H. B. Robinson	3	W/44	W/44F	Oct 84
D. C. Cook	4	W/51	W/54F	Mar 89
Indian Point 3	4	W/44	W/44F	Jun 89
Palisades	2	CE	CE	Mar 91
Millstone 2	2	CE-67	BWC	Jan 93
North Anna 1	3	W/51	W/54F	Apr 93
V. C. Summer	3	W/D3	W/Δ75	Dec 94
North Anna 2	3	W/51	W/54F	May 95
Ginna	2	W/44	BWC	Jun 96

Abbreviations:

W = Westinghouse
CE = Combustion Engineering
BWC = Babcock & Wilcox Canada

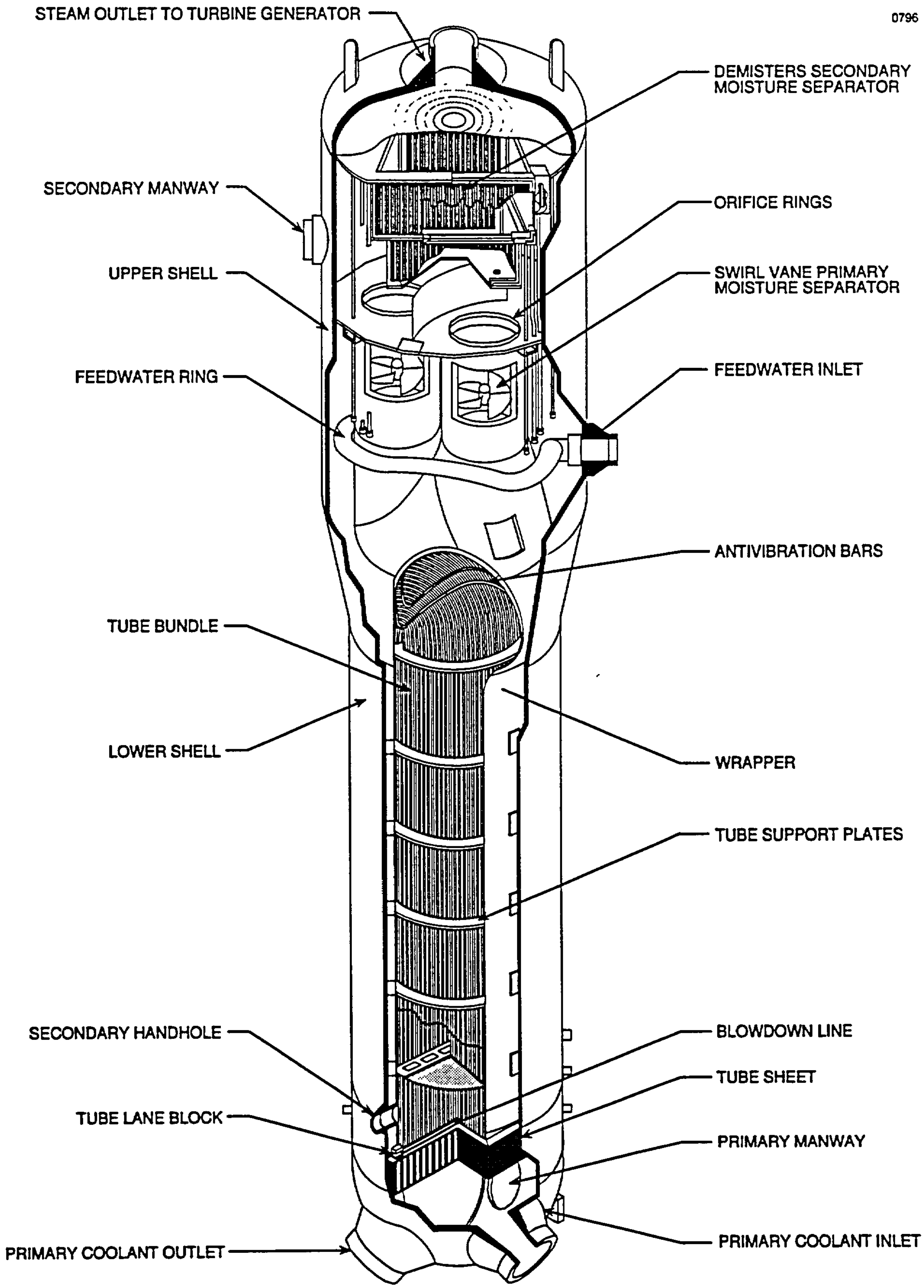


Figure 4.5-1 Typical Westinghouse Steam Generator

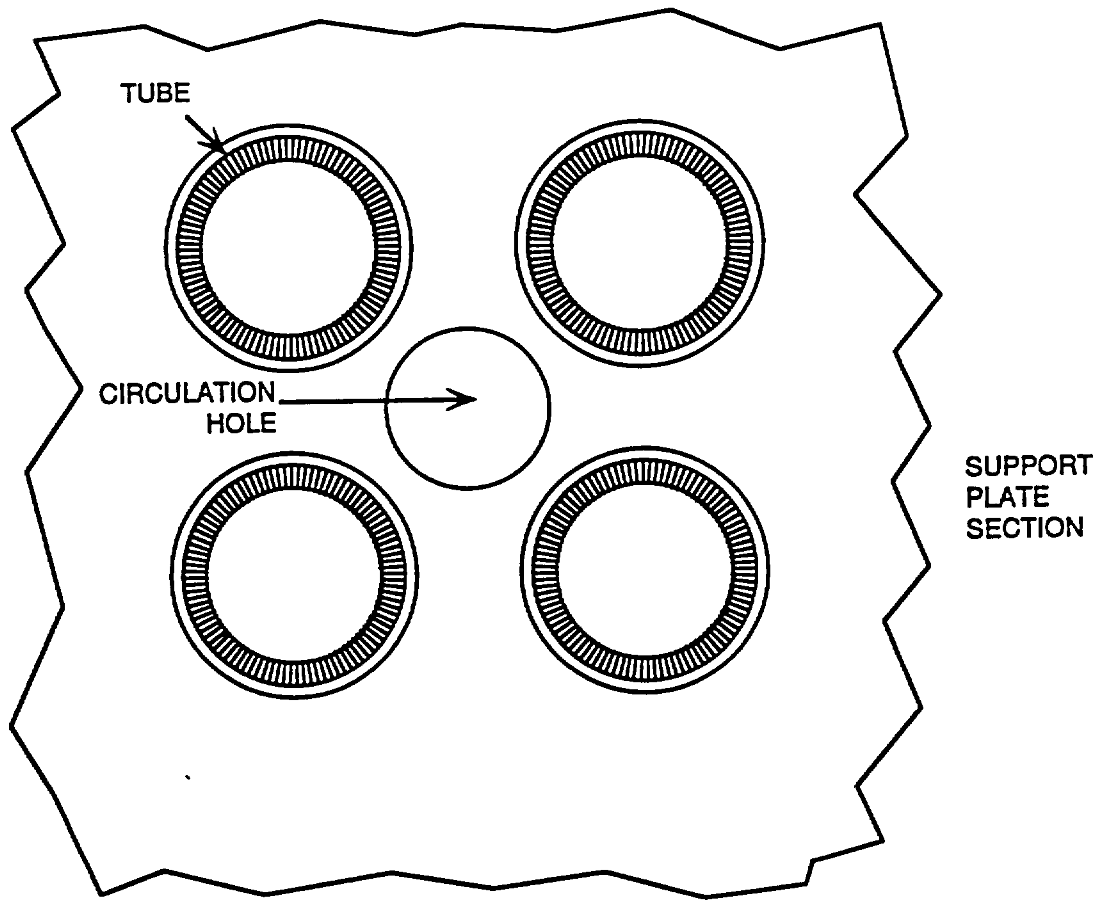


Figure 4.5-2 Drilled Support Plate

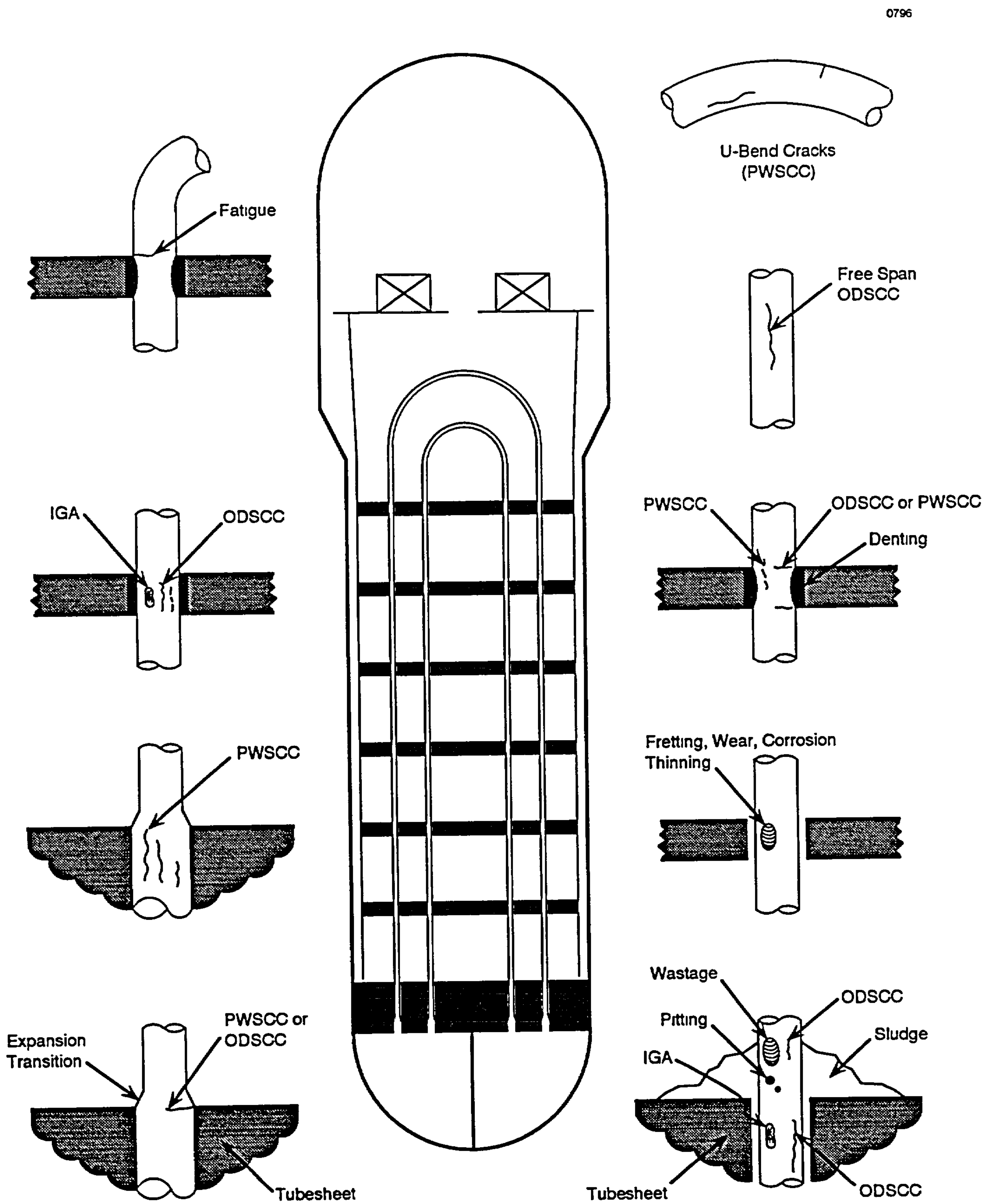
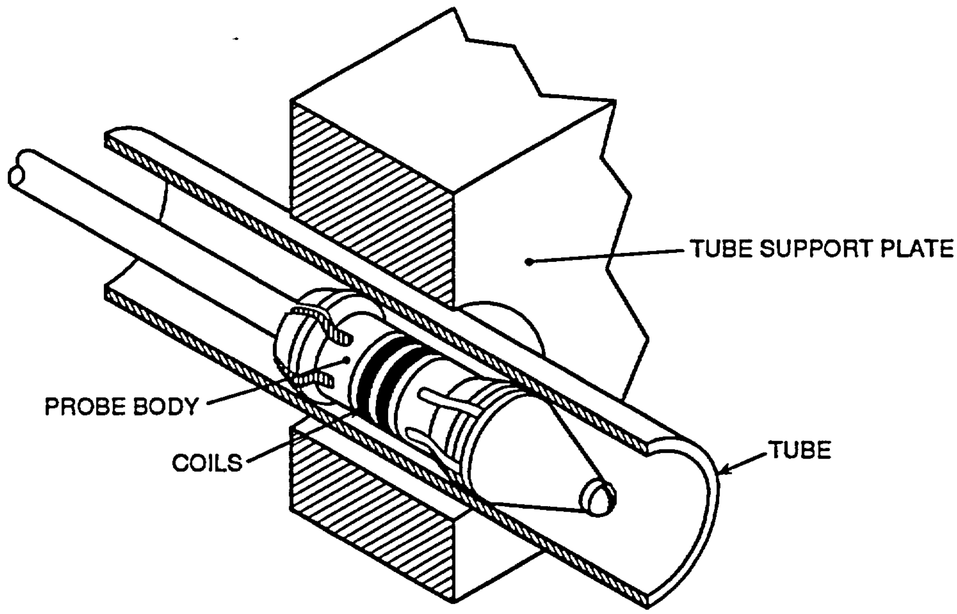
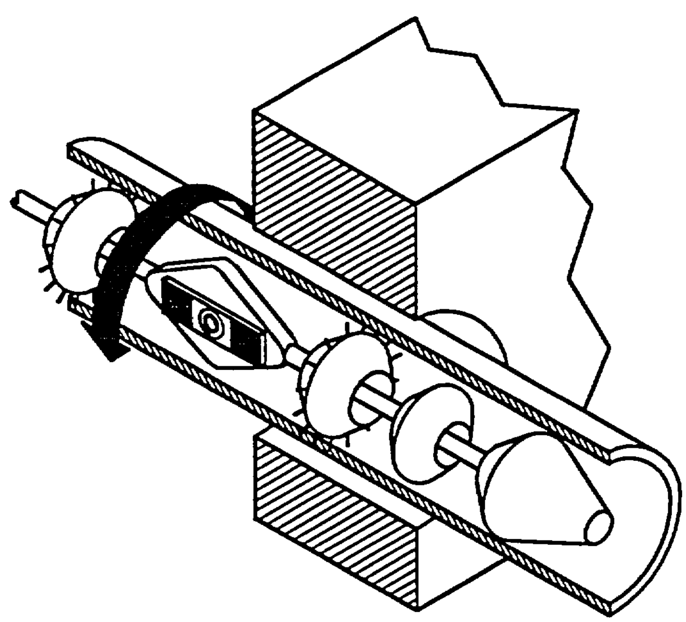


Figure 4.5-3 Examples of SG Tube Degradation Mechanisms

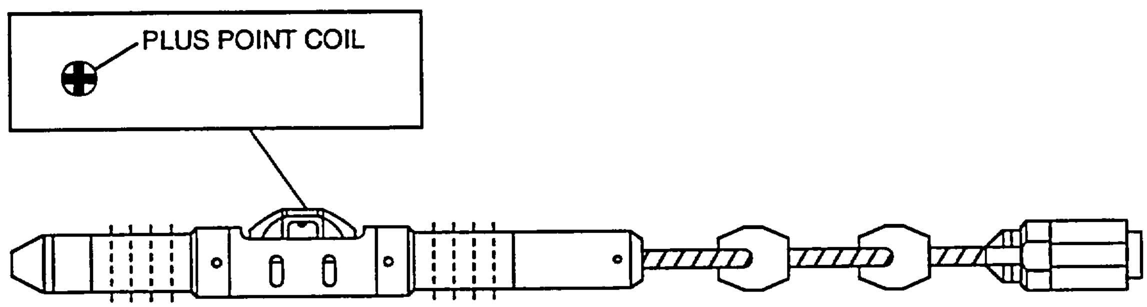


Bobbin Coil



Rotating Pancake Coil

Figure 4.5-4 Bobbin and Rotating Pancake Coils



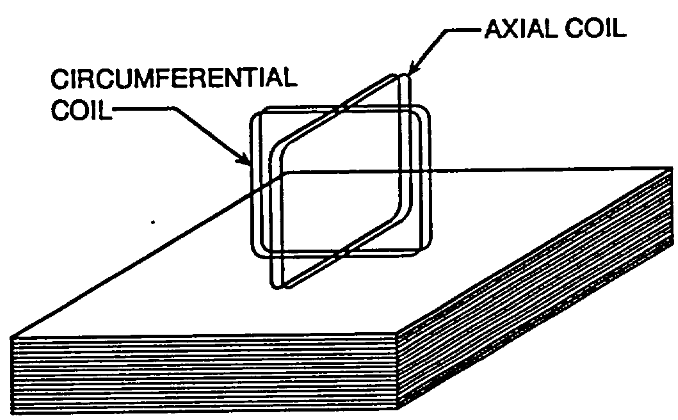


Figure 4.5-5 Plus Point Probe

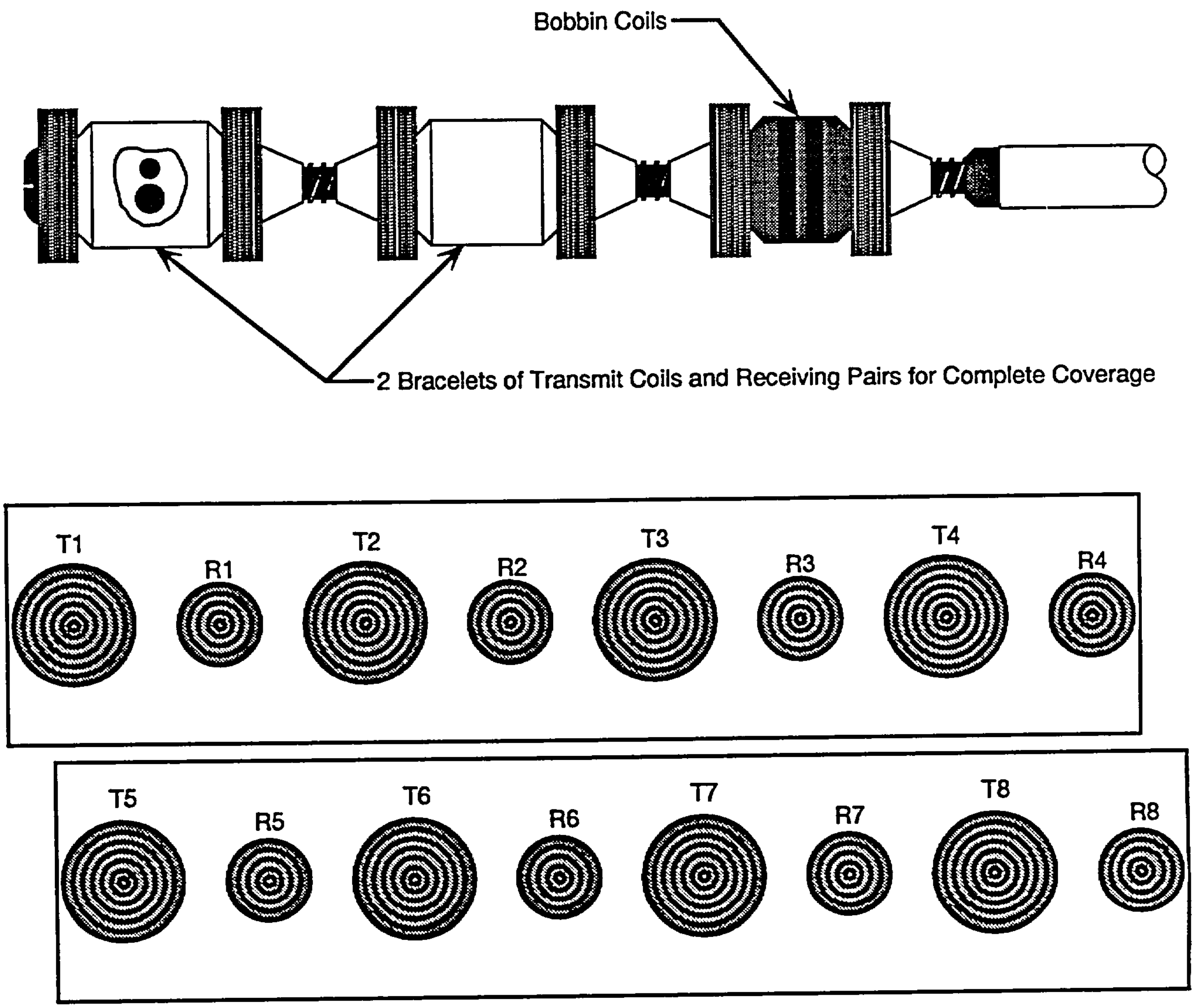


Figure 4.5-6 Cecco Probe

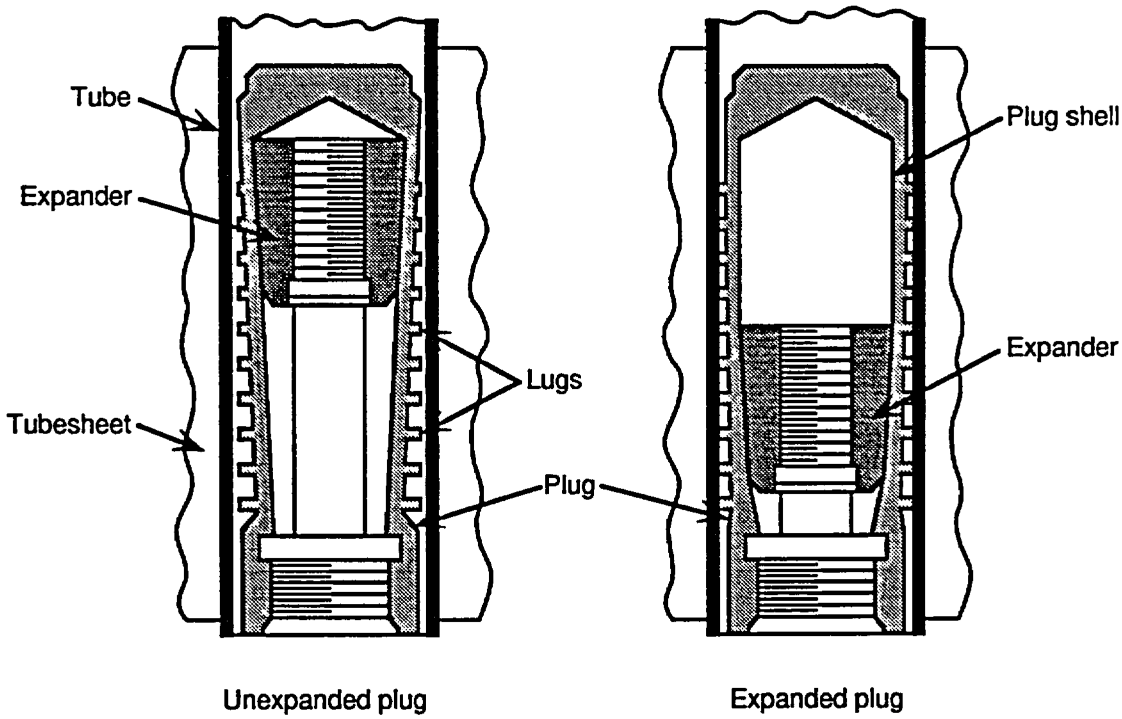


Figure 4.5-7 Tube Plug

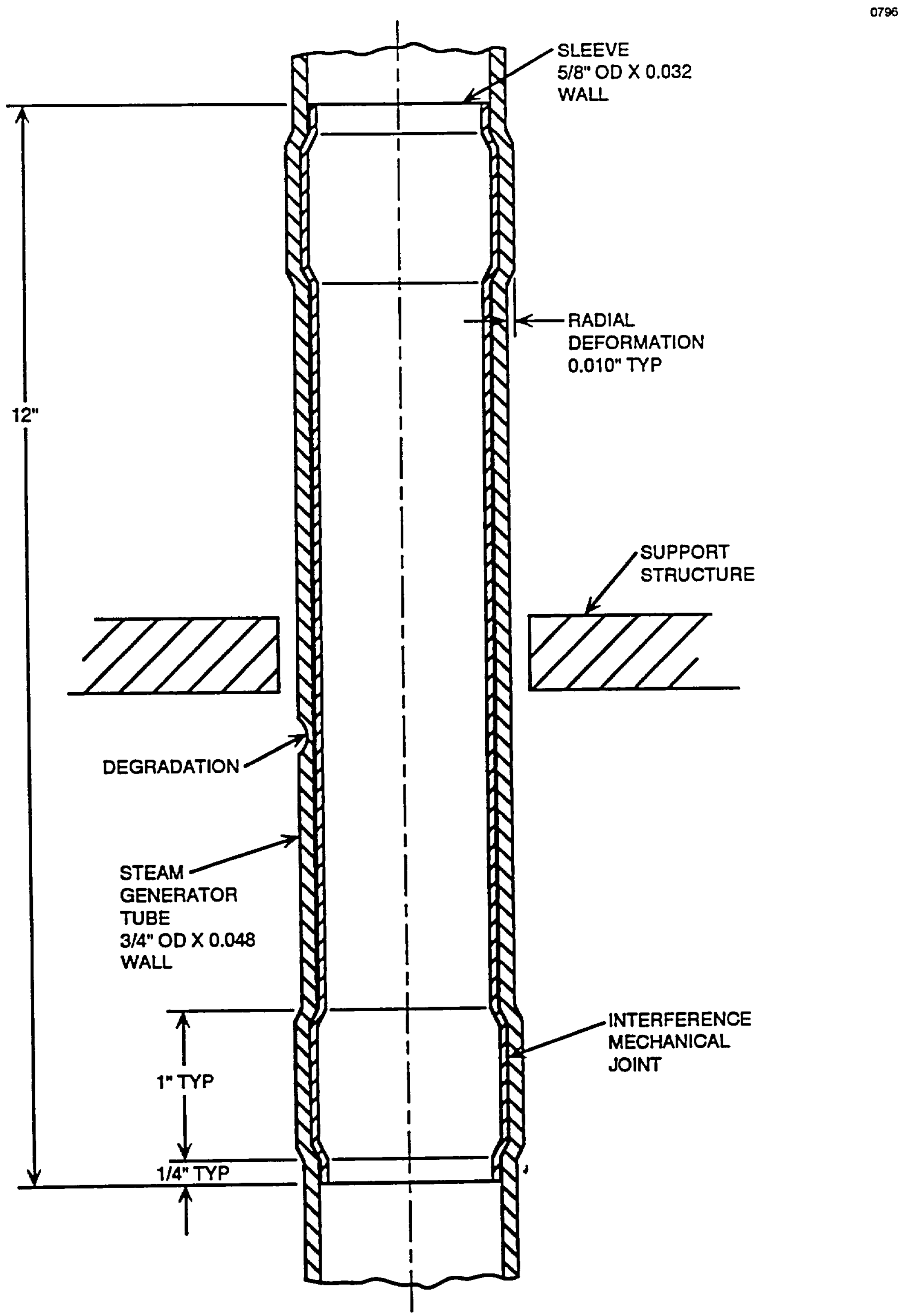


Figure 4.5-8 Tube Sleeve

Westinghouse Technology Advanced Manual

Section 4.6

Steam Generator Tube Rupture

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

4.6 STEAM GENERATOR TUBE RUPTURE

Learning Objectives:

1. Discuss why operator intervention is necessary to limit or prevent radiological releases during a steam generator tube rupture (SGTR) event.

2. Discuss the primary-side and secondary-side indications of an SGTR in the control room.

3. Discuss how the affected generator may be identified either prior to or following the reactor/turbine trip.

4. List the initial actions taken by the operator once the affected steam generator has been identified.

5. Discuss the actions required to stop the primary-to-secondary leakage.

6. Discuss the problems associated with the following:

   a. Secondary-to-primary leakage
   b. Steam generator overfill.

7. List the principal systems/components affected by a loss of site power (LOSP).

8. Discuss how plant cooldown and pressure control are accomplished with an SGTR and LOSP.

9. Discuss what affect the following events had on the SGTR transient at the Ginna plant:

   a. Tripping of the reactor coolant pumps
   b. Failure of pressurizer power-operated relief valve (PORV)
   c. Automatic operation of letdown valves
   d. Pressurizer relief tank failure
   e. Steam generator safety valve failure.

4.6.1 Introduction

Of all the major accidents that have actually occurred at operating PWRs, steam generator tube failures have occurred most frequently. The nuclear industry has implemented many programs to reduce the incidents of tube failures, such as secondary side inspections, improved steam generator designs and water chemistry control, and more reliable eddy current tube inspection techniques. Nevertheless, a steam generator tube failure may remain one of the more likely accidents. Such accidents provide a direct release path for contaminated primary coolant to the environment via the secondary side safety and relief valves. Accumulation of water in the SG secondary side can also lead to an overfill condition which can severely aggravate the radiological consequences and increases the likelihood of subsequent failures.

Unlike other loss of coolant accidents (LOCA), a steam generator tube failure demands substantial operator involvement early in the event. Timely operator intervention is necessary to prevent steam generator overfill and limit the radiological releases.

The following sections describe the plant response to an actual and a postulated steam generator tube failure. A steam generator tube rupture event begins as a breach of the primary coolant barrier between the reactor coolant system and secondary side of the steam generator, i.e., the steam generator tube, Figure 4.6-1. Although this relatively thin barrier is designed with substantial safety margin to preclude bursting even when subjected to full primary system pressure, the harsh secondary side environment may attack the steam generator tubes resulting in excessive tube wall thinning or cracking over time. Although improved secondary side chemistry has greatly reduced the frequency of tube failures attributed to chemical corrosion, foreign objects in the steam generator secondary have resulted in relatively rapid tube degradation and eventually tube failure (Prairie Island [1979] and Ginna [1982]). Even more recently (North Anna [1987]), tube failure was caused by flow-induced fatigue cracking.

4.6.2 Expected Plant Response to SGTR Event with Timely Operator Intervention

This section contains a description of the expected plant response to a postulated steam generator tube rupture accident and the actions, both operator initiated and automatic, which may occur during recovery. System response and recovery actions with offsite power available, section 4.6.2.1, and the effects of a loss of offsite power coincident with turbine trip, section 4.6.2.2, are discussed. As previously noted, the trends described are only representative since variations in manual actions or operable equipment as well as rupture size and specific plant design will result in slightly different system conditions. In the transient plots presented, a tube failure is to be the initiating event and it occurs when the plant is at full power.

4.6.2.1 SGTR Transient: Offsite Power Available

Since the primary system pressure (nominally 2235 psig) is initially much greater than the steam generator pressures (nominally 1000 psig) reactor coolant flows from the primary into the secondary side of the affected steam generator. In response to this loss of reactor coolant, pressurizer level and pressure decrease at a rate which is dependent upon the size and number of failed tubes, as shown in Figure 4.6-2. The Pressure decreases as the steam bubble in the pressurizer expands. Normally, charging flow will automatically increase and pressurizer heaters will energize in an effort to stabilize pressure and level. However, if leakage exceeds the capacity of the chemical and volume control system (CVCS), reactor coolant inventory will continue to decrease and eventually lead to an automatic reactor trip signal. If turbine load is not reduced, reactor trip will most likely occur on overtemperature ΔT. For the expected case, however, turbine load will be decreased either automatically or manually so that reactor trip will occur on low pressurizer pressure. Normal letdown flow would isolate and pressurizer heaters would turn off on low pressurizer level.

On the secondary side, leakage of contaminated primary coolant will increase the activity of the secondary coolant resulting in high radiation indications from the air ejector radiation monitor and blow down line radiation monitors. Although these alarms may lag indications of a loss of reactor coolant, depending on the transport time to the radiation monitors, they have sounded nearly simultaneously with pressurizer low level indications during past tube failure events and generally provide the earliest diagnosis of a steam generator tube rupture. As primary coolant accumulates in the affected steam generator, normal feedwater flow is automatically reduced to compensate for high steam generator level. Consequently, a mismatch between steam flow and feedwater flow to the affected steam generator may be observed. This potentially provided early confirmation of a tube failure event and also identifies the affected steam generators. However, such a mismatch may not be noticeable for smaller tube failures because of the relatively large normal feedwater/steam flow rates. The water level in the affected steam generators may not be significantly greater than that of the intact steam generators prior to reactor trip as the normal feedwater control system automatically compensates for changes in steam flow rate and steam generator level due to primary-to-secondary leakage.

The time between initial tube failure and reactor trip also depends on the leak rate. In most cases sufficient time will be available (greater than three minutes) for the operator to perform a limited number of actions to either prevent or prepare for reactor trip. Such actions are likely to include starting additional charging pumps, energizing pressurizer heaters if not done automatically, reducing the load on the turbine, and possibly manually tripping the reactor. These actions, with the exception of manual reactor trip, will tend to delay an automatic trip signal. In addition, these actions can have a significant effect on the system response following reactor trip which may impact the longer term recovery. For example, as turbine run back proceeds, the mismatch between core power and turbine load causes the average coolant temperature (T_{avg}) to increase until the rod control and steam dump system actuate to restore programmed T_{avg}. A period of time may exist when T_{avg} is greater than nominal full power conditions. If reactor trip occurs during this time, the resulting cooldown of the primary system is larger when the steam dump system actuates to establish no-load conditions. The combination of a delayed reactor trip and greater shrinkage of reactor coolant may result in a significantly lower minimum RCS pressure following reactor trip. In that case RCP trip criteria may be met. This may also result in a greater steam generator inventory before recovery actions are initiated which would reduce the time available to steam generator overfill.

Following reactor trip, core power rapidly decreases to decay heat levels, steam flow to the turbine is terminated, and the steam dump system actuates to establish no-load coolant temperatures in the primary system (Figure 4.6-3). Shortly thereafter, the normal feedwater control system increases feedwater flow to compensate for shrinkage in steam generator level due to reduced steam flow. RCS pressure decreases more rapidly as energy transfer to the secondary shrinks the reactor coolant and tube rupture flow continues to deplete primary inventory. This decrease in RCS pressure results in a low pressurizer pressure SI signal soon after reactor trip. Normal feedwater flow is automatically isolated on the SI signal which also actuates the auxiliary feedwater (AFW) system to deliver flow to all steam generators. For some plants, low water level is a combination of the steam generators coincident with the SI signal is required to actuate some components of the AFW system. However, since level drops below the narrow range on reactor trip from full power (Figure 4.6-4) the AFW system will also actuate on the SI signal for plants with this logic. If trip occurs at a lower power for these plants, AFW flow may not be initiated until sometime after the SI signal occurs. Eventually, manual action is required to decrease auxiliary feedwater flow to maintain the steam generator water level on the narrow range span. The expected sequence of automatic actions following reactor trip is presented in Table 4.6-1.

Secondary-side pressure will increase rapidly after reactor trip as automatic isolation of the turbine momentarily stops steam flow from the steam generators (Figure 4.6-4). Normally, automatic steam dump to the condenser will actuate to dissipate energy transferred from the primary, thereby limiting the secondary pressure increase. Since the intact and ruptured steam generators are connected via the main steam header, no significant difference in pressures will be evident at this time.

Initially, SI flow and AFW flow will absorb decay heat and decrease the reactor coolant temperature below no-load until AFW flow is manually throttled to maintain steam generator level in the narrow range. Steam flow should stop when the reactor coolant temperature decreases below no-load temperature (Figure 4.6-4) and the steam generator pressures may slowly decrease as the cold AFW flow condenses steam. At low decay heat levels or for multiple tube failures the reactor coolant temperature may continue to decrease due to SI flow even after AFW flow is throttled.

Pressurizer level decreases more rapidly following reactor trip as the reactor coolant shrinks during the post-trip cooldown and primary-to-secondary leakage continues to deplete coolant inventory. Although the minimum pressurizer level is dependent upon a number of parameters, including initial pressurizer level, initial power level, the size of the tube failure, operation of pressurizer heaters, and pre-trip operator actions, it is likely that level will be nearly off-scale low when SI is actuated. With SI actuated, the primary system will tend toward an equilibrium condition where break flow and coolant shrinkage are matched by SI flow (Figure 4.6-5). If break flow and shrinkage are initially greater than SI flow, pressurizer level and pressure will continue to decrease until quasi-equilibrium conditions are reached. In some cases, such a multiple tube failures or reduced SI capacity, RCS pressure may momentarily decrease to saturation until SI flow and AFW flow cool the primary system below the saturation temperature of the steam generators. Conversely, if SI flow exceeds primary-to-secondary leakage and coolant shrinkage, the pressurizer level and pressure will increase until equilibrium is achieved. The equilibrium RCS pressure depends on the size of the tube failures, capacity of the SI system, and cooldown rate of the primary. However, since leakage from the RCS is a function of both pressure and temperature, RCS pressure may continue to slowly decrease until reactor coolant temperatures are stabilized.

For high pressure SI plants, the pressurizer may refill to a relatively high level prior to operator intervention if the tube failure is small. However, in the more likely case, pressurizer level will return on span and will stabilize at a value significantly below nominal level, as shown in Figure 4.6-2. A point of confusion often noted occurs during simulation of a steam generator tube failure event where pressurizer level continues to increase toward an overfill condition following actuation of the SI system. While the pressurizer could fill for small tube failures in high pressure SI plants, in some cases this response has been attributed to modelling limitations of the pressurizer. The operator should be aware that although filling of the pressurizer is possible, it is not generally expected. It should also be clear that the reactor coolant temperature trend and operator actions, such as throttling AFW flow, will affect the pressurizer level.

As previously mentioned, the steam generator level may drop out of the narrow range following reactor trip, as shown in Figure 4.6-4. AFW flow will begin to refill the SGs, distributing approximately equal flow to all SGs. Since primary-to-secondary leakage adds additional inventory which accumulates in the ruptured SG, the level will return significantly earlier and will continue to increase more rapidly. This response provides confirmation of a SGTR event and also identifies the affected SG. Although these symptoms will be evident soon after reactor trip for larger tube failures, the SG level response may not be noticeably different or may be masked by non-uniform AFW flows for smaller tube failures in one or more SGs. In that case, high radiation indications may be necessary for positive identification of a ruptured SG. In such instances of smaller tube failures, the break flow would be less and, consequently, more time would be available for recovery prior to filling the affected S/G with water.

Once a tube failure has been identified, recovery actions begin by isolating steam flow from and stopping feedwater flow to the affected SGs In addition to minimizing radiological releases, this also reduces the possibility of filling the affected SG with water by (1) minimizing the accumulation of feedwater flow and (2) enabling the operator to establish a pressure differential between the ruptured and intact SGs as a necessary step toward terminating primary-to-secondary leakage. In the analysis results, the operator was assumed to isolate the affected SG when the water level returned into the narrow range (> 15%). With steam flow and feedwater flow terminated, the affected SG pressure will slowly increase as primary-to-secondary leakage compresses the steam bubble in the SG.

High pressure SI plants would also show similar trends. Eventually an SG atmospheric relief valve would lift unless actions to stop leakage into the affected SG are completed.

After isolation of the ruptured SG, the RCS is cooled to less than saturation at the ruptured SG pressure by dumping steam from only the intact SGs. This insures adequate subcooling in the RCS after depressurization to the ruptured SG pressure in subsequent actions. With offsite power available, the normal steam dump system to the condenser provides sufficient capacity to perform this cooldown rapidly, as demonstrated in Figure 4.6-6.

RCS pressure will decrease during this cooldown as shrinkage of the reactor coolant expands the steam bubble in the pressurizer (Figure 4.6-6). For multiple tube failures, RCS pressure (Figure 4.6-7) may decrease to less than the ruptured SG pressure as steam voids, which were generated during initial RCS depressurization, condense. Reverse flow, i.e., secondary-to-primary leakage, during this time would reduce the inventory in the ruptured S/Gs and delay steam generator overfill, as shown in Figure 4.6-7.

When the cooldown is completed SI flow again increases RCS pressure toward an equilibrium value where break flow matches SI flow. Consequently, SI flow must be terminated to stop primary-to-secondary leakage. However, adequate coolant inventory must first be ensured. This includes both sufficient reactor coolant subcooling and pressurizer inventory to maintain a reliable pressurizer level indication after SI flow is stopped. Since leakage from the primary side will continue until RCS and ruptured SG pressures equalize, an excess amount of inventory is required before stopping SI flow. The "excess" amount of inventory required depends upon the RCS pressure and reduces to zero when RCS pressure equals the pressure in the ruptured SG. It is necessary to accommodate the decrease in pressurizer level after SI flow is stopped. To establish sufficient inventory, RCS pressure is decreased by condensing steam in the pressurizer using normal spray. This increases SI flow and reduces break flow, which refills the pressurizer, as illustrated in Figures 4.6-8 and 4.6-9. Note that although the cooldown of the primary side also decreased RCS pressure, the pressurizer did not refill since the net effect reduced coolant volume. Similarly, spraying the pressurizer to decrease RCS pressure concurrently with the primary side cooldown is not as effective in refilling the pressurizer, as shown in Figure 4.6-10.

For multiple tube failures, RCS pressure may decrease below the ruptured steam generator pressure before pressurizer level returns on scale. In that case, reverse flow through the failed tubes will supplement SI flow in refilling the pressurizer. Conversely, for smaller tube failures, pressurizer inventory may stay on scale and additional actions to restore inventory would not be necessary.

Previous actions were designed to establish adequate RCS subcooling, secondary side heat sink, and reactor coolant inventory to ensure SI flow is no longer required. When these actions have been completed, SI flow must be stopped to prevent repressurization of the RCS and to terminate primary-to-secondary leakage. With SI flow stopped, residual break flow will reduce RCS pressure to equilibrium with the ruptured SG, as shown in Figure 4.6-11. RCS temperature, pressurizer level, and affected SG levels will stabilize (Figure 4.6-12) and no further uncontrolled releases of radiological effluent from the ruptured SG will occur. Note that although the level in the affected steam generator may reach the top of the narrow range span, significant volume still exists before the SG fills with water.

4.6.2.2 SGTR Transient: Offsite Power Not Available

The principal systems/components affected by a loss of site power are the steam dump system, reactor coolant pumps, and RCS pressure control. The effect of each of these on the system response and recovery is discussed.

The steam dump system is designed to actuate following loss of load or reactor trip to limit the increase in secondary side pressure. Without offsite power available, the steam dump valves, which bypass the turbine to the condenser, will remain closed. Hence, energy transferred from the primary will rapidly increased SG pressures after reactor trip until the atmospheric relief valves lift to dissipate this energy, as shown in Figure 4.6-13. Since the secondary side temperature increase is greater, sensible energy transfer from the primary side following a reactor trip is reduced. Consequently, RCS pressure decreases more slowly, as illustrated in Figure 4.6-14, so that SI actuation and all attendant automatic actions are delayed. A typical sequence of events without offsite power available is also presented in Table 4.6-1.

RCPs trip on a loss of offsite power and a gradual transition to natural circulation flow ensues. The cold leg temperature trends toward the SG temperature as the fluid residence time in the tube region increases. Initially, the core ΔT decreases as core power decays following reactor trip and, subsequently, increases as natural circulation flow develops (Figures 4.6-15 and 4.6-16). Without RCPs running, the upper head region becomes inactive, and the fluid temperature in that region will significantly lag the temperature in the active RCS regions. This creates a situation more prone to voiding during the subsequent cooldown and depressurization.

Sufficient instrumentation and controls are provided to ensure that necessary recovery actions can be completed without offsite power available. Although the recovery methods are the same with or without offsite power available, the equipment used may be different. The RCS is cooled using the PORVs on the intact SGs since neither the steam dump valves nor the condenser would be available without offsite power. Even with one SG out of service, these valves provide sufficient capacity to complete the initial cooldown rapidly, as shown in Figure 4.6-17. Note that the hot leg temperature does not respond as quickly as the cold leg and SG temperatures since RCPs are not running.

Under natural circulation conditions subsequent actions to isolate the affected SGs and cooldown the intact RCS loops may stagnate the affected loop. Consequently, the hot leg fluid in that loop may remain warmer than the unaffected loops. Similarly, SI flow into the stagnant loop cold leg may rapidly decrease the fluid temperature in the cold leg, downcomer, and pump suction regions significantly below the rest of the RCS.

With RCPs stopped, normal pressurizer spray would not be available. Consequently, RCS pressure must be controlled using pressurizer PORVs or auxiliary spray. Although a PORV enables more rapid RCS depressurization (Figure 4.6-18), it also results in an additional loss of reactor coolant which may rupture the PRT and contaminate the containment. Auxiliary spray conserves reactor coolant but may create excessive thermal stresses in the spray nozzle which could result in nozzle failure. Auxiliary spray is recommended only if normal spray and PORVs are not available.

Since the upper head region is inactive, voiding may occur in this region during RCS depressurization. This will result in a rapidly increasing pressurizer level indication as water displaced from the upper head replaces steam released or condensed from the pressurizer. This behavior was observed during the Ginna tube failure event, when the pressurizer PORV failed to close. The extent of voiding is limited to the inactive regions of the RCS provided subcooling is maintained at the core exit. However, flashing in the inactive regions may slow further RCS depressurization to cold shutdown conditions.

Once SI flow is stopped, no additional primary-to-secondary leakage or uncontrolled radiological releases from the affected SGs should occur. This plant response is similar with or without offsite power available.

The automatic protection systems are more than sufficient to maintain adequate core cooling even for multiple tube failures. However, extensive operator actions are required to stop primary-to-secondary leakage which could lead to a steam generator overfill condition if not terminated expeditiously. The system response to a SGTR before and immediately after reactor trip has been described. From this description the symptoms which identify both the tube failure event and the affected SGs should be evident, including high or increasing secondary side radiation, and steam generator level response. These symptoms provide the basis for diagnostics in the emergency operating procedures.

It must be emphasized that although strong similarities exist, each tube failure is unique. Variations in break size and plant specific features, such as SI capacity and operator response times, will affect system conditions.

4.6.3 R.E. Ginna Tube Rupture

On January 25,1982, the R.E. Ginna Nuclear Power Plant experienced a design-basis steam generator tube rupture. This resulted in the maximum flow from a single tube.

The final safety analysis report (FSAR) assumes that the break flow is terminated by operator action within 30 to 60 minutes. The procedures available to the operators at the time proved to be inadequate to meet this time requirement. Several procedure changes have occurred because of these inadequacies. Major changes address specific guidance on safety injection reset and safety injection termination with suspected reactor upper head voiding. Also of major significance are the criteria for tripping and restarting reactor coolant pumps.

The report on the Ginna steam generator tube rupture is published as NUREG-0909. The event is described in nine phases. This nine phase description, along with an event chronology is included as Table 4.6-3 of this chapter. Note that other equipment failures made this event unique, such as PORV failure to close and SG code safety valve failure to fully reseat. Also the design of the CVCS allowed the letdown isolation valve to open, causing overpressure in the pressurizer relief tank (PRT) and release into the containment.

The R.E. Ginna Nuclear Power Plant is a 1520-MWt, two-loop PWR designed by Westinghouse. A diagram of the major plant systems and components is shown on Figure 4.6-19. Figure 4.6-20 shows the instrument locations in the reactor coolant system, pressurizer, and PRT.

4.6.3.1 Event Phase 1: Steady-State Operation (Period before 9:25 a.m., 1/25/82)

Prior to 9:25 a.m., the plant was operating at full power, steady-state conditions. The major primary and secondary system parameters and their steady-state values are listed in Table 4.6-2. These parameters indicate that the plant was in a normal full power condition. No important systems were out of service and no abnormal conditions existed in any of the major parameters.

4.6.3.2 Event Phase 2: Tube Rupture and Initial Depressurization (9:25 a.m. to 9:30 a.m.)

At 9:25 a.m., there was a sudden rupture of a single tube in the B steam generator. Detailed information from the plant process computer is available for the period beginning at 9:26 a.m. This information was used to develop the graphs of pressurizer (PZR) pressure and level versus time (Figures 4.6-21 and 4.6-22). The initial depressurization from 2197 psig to approximately 2100 psig and the associated drop in pressurizer level from 47% to 30% occurred between 9:25:25 a.m. and 9:26:30 a.m. The depressurization and level drop were terminated by automatic and manual actions to increase the charging flow from 30 gpm to at least 60 gpm (corresponding to full flow from one charging pump) and thermal expansion of the water in the reactor coolant system associated with the ordered load reduction. This indicates that the initial leak rate was approximately 750 gpm.

A level deviation alarm resulted when the water level in the B SG exceeded its setpoint of 52%. The water level increased because of the flow from the reactor coolant system to the SG through the ruptured tube. The increased water level was sensed by the feedwater control system, which reduced feedwater flow by modulating the feedwater control valve. The difference between feed flow and steam flow produced the steam flow/feed flow mismatch alarm from the B SG. Simultaneously, a radiation alarm on the air ejector indicated a leak from the reactor coolant system to the secondary system. These were important symptoms of a tube rupture in B SG.

At 9:27:11 a.m. (Figure 4.6-22) a more rapid reactor coolant system depressurization and level decrease began. This was the result of a reactor coolant cooldown and a continuing leak of approximately 750 gpm. This leak resulted in a reactor trip at 9:28 a.m. on low pressurizer pressure (~1900 psig), an automatic safety injection actuation signal on low pressurizer pressure (~1720 psig), and a containment isolation signal on safety injection actuation. The safety injection actuation signal started all three high pressure safety injection pumps and the two motor driven auxiliary feedwater pumps. The containment isolation signal resulted in the closure of all containment isolation valves, termination of main feedwater flow, and termination of charging flow. The turbine driven auxiliary feedwater pump subsequently started automatically on low water level (17%) in both steam generators. Shortly after these actuation signals, the pressurizer emptied of water, and the reactor coolant system pressure dropped to approximately 1200 psig. The minimum system pressure was apparently determined by the temperature of the hottest fluid in the reactor coolant system. This fluid would have flashed when the system pressure dropped below the saturation pressure corresponding to its temperature. This initial flashing in the reactor coolant system would have occurred when the temperatures in the pressurizer surge line and reactor vessel upper head were near or above 576°F, the saturation temperature corresponding to 1270 psig.

Immediately after the reactor, turbine, and feedwater trips, the narrow-range A and B SG water level instruments indicated a level drop from about 47% to about 10%, normal for a trip from full power, while the wide-range level instrument indicated a slight increase in level. This discrepancy was believed to result from cold calibration of the wide-range instrument and the fact that its lower pressure tap was located just above the tube sheet. The narrow-range instrument is calibrated at operating temperature of the SG and its lower pressure tap is located just above the top elevation of the tube bundle.

Approximately 50 seconds after the SI signal occurred, the reactor operators verified that the pressurizer pressure was less than 1715 psig and manually tripped the reactor coolant pumps in accordance with Ginna procedures.

During normal operations, both seal injection and component cooling water are provided to the reactor coolant pumps. The seal injection flow was terminated upon SI because the charging pumps were tripped automatically.

In addition, the piping that returns the seal water to the CVCS was isolated by the containment isolation signal. After the seal return valve closed, reactor coolant system leakage through the reactor coolant pump seals pressurized the seal return line. As shown by the pressurizer relief tank level indication, the relief valve on this line lifted. The pumps can be operated without seal injection provided component cooling water is available and the seal leakage is less than five gpm (Ginna procedure). Therefore, the reactor coolant pump trip was a result of the procedural requirement to trip the pumps to avoid exacerbating certain small-break loss of coolant accidents.

Numerous valves inside containment were affected when the instrument air was isolated at 9:28 a.m from the containment isolation signal. The important valves for this event were the two pressurizer PORVs, the pressurizer spray valves, the CVCS charging and letdown valves, and the pressurizer auxiliary spray valve. Except for the level control valve in the CVCS, all these valves fail closed. The pressurizer PORVs have a backup nitrogen supply that is available to operate the valves.

4.6.3.3 Event Phase 3: Natural Circulation and Reactor Coolant System Repressurization (9:30 a.m. to 10:07 a.m.)

Following the initial depressurization, the SI pumps injected water into the reactor coolant system, increasing the volume of water in the system and increasing the system pressure to 1350 psig. During this period, the reactor-coolant-system-to-B-SG pressure difference was approximately 300 psi and the leakage into the B SG continued at a rate of approximately 400 gpm. Figure 4.6-23 presents estimates of SI flow and break flow versus pressure. This figure indicates that the reactor coolant system and B SG should establish a dynamic equilibrium between high pressure injection flow and break flow with a reactor coolant system pressure of 1410 psig, which corresponds to an indicated reactor coolant pressure of 1385 psig. This condition developed at approximately 10:00 a.m. during the event.

The temperature difference from the cold legs (Figure 4.6-24) to the hot legs initially decreased, since the reactor trip caused a rapid drop in the reactor core heat generation, and reached a minimum value of 20°F. Following the RCP trip at 9:29 a.m., the reactor coolant flow rates decreased. As flow decreased, natural circulation developed, with the reactor core as the heat source, and the elevated steam generators as the heat sink.

At 9:32 a.m. the turbine-driven auxiliary feedwater steam supply valve from B SG was shut in accordance with the SGTR procedure. In addition, the motor-driven auxiliary feedwater pump was isolated from the B SG. To confirm that the leak was from the B SG, as suspected, a check of B steam line radiation level was made using a portable radiation monitor. The indicated reading (approximately 30 mrem/hr) gave positive indication of the affected SG approximately 15 minutes after the initial alarms had indicated that a problem existed.

At 9:40 a.m the B SG was isolated by closing the MSIV, and no further cooling was taking place in the B SG. This caused the flow in the B reactor coolant loop cold leg to stagnate and to reverse direction as water in the B loop cold leg was drawn toward the ruptured tube. The reverse flow in the B reactor coolant cold leg continued throughout the event.

Prior to 9:40 a.m., the reactor coolant leaking into the B SG was circulated throughout the main steam, main feedwater, and condensate systems. After 9:40 a.m. the B SG main steam isolation valve was closed and the tube leak caused an increase in the indicated steam generator water level. The pressure in the B SG began to increase when the turbine-driven auxiliary feedwater terminated at 9:46 a.m. The B SG narrow-range water level indication went off scale high at 9:55 a.m. Later the attached steam line also flooded.

Throughout this phase, the A SG continued to dump steam into the main condenser. The RCS cooldown rate during this period can be seen by observing the change in the A loop temperature versus time in Figure 4.6-24.

The only radiation alarm from the SG blowdown system occurred at 9:50 a.m., 22 minutes after the B SG blowdown piping isolation valve closed on containment isolation. The radiation monitor is located downstream of the sample line isolation valves, which were also closed upon containment isolation.

The SI signal was reset at 9:57 a.m. The containment isolation signal was also reset in order to restore instrument air and gain control of air-operated valves inside containment.

At 10:04 a.m., one charging pump was restarted, although the SGTR procedure called for starting all available charging pumps.

4.6.3.4 Event Phase 4: Pressurizer PORV Operation (10:07 a.m. to 10:15 a.m.)

Reducing the RCS pressure to reduce the tube leakage is an important step in recovery from a tube rupture event. The first attempt to reduce RCS pressure occurred at 10:07 a.m. when one PORV was opened for a few seconds. The valve was successfully cycled three times but failed to close on the fourth cycle at 10:09 a.m. The operators then closed the block valve to terminate flow through the stuck-open PORV. The normal closure time for the block valve is approximately 35 seconds. The plant process computer printout shows that pressure in the RCS was increasing at 10:11 a.m., indicating that the block valve was closed by that time. In addition, the temperature rise in the PRT terminated at 10:12 a.m.

While the PORV was open RCS pressure dropped from 1350 psig to 850 psig (Figure 4.6-25). For the period from 10:09 a.m. to 10:11 a.m. the RCS pressure was lower than the B SG pressure. This low RCS pressure caused a temporary reversal in primary-to-secondary break flow, an increase in SI flow, and flashing of water in the reactor vessel upper head and B SG tubes. While the PORV was stuck open the pressurizer level increased rapidly from 6% to 100%. The pressurizer was filled by water displaced by steam formation in the reactor vessel upper head and inside the B SG tubes, flow from the B SG into the RCS through the ruptured tube, and SI and charging flow.

The indicated rate of increase of pressurizer level, beginning at 10:09 a.m., corresponds to a computed water inventory rate of change of 405 ft^3/min. Since the PORV was opened for about two minutes after 10:09 a.m., approximately 810 ft^3 of water would have left the pressurizer. This value is reasonably close to the estimated value of water volume available, that is 765 ft^3.

Since the water volume in the pressurizer at 10:09 a.m. was approximately 100 ft^3, these calculations imply that a relatively small volume (35 to 100 ft^3) of water was discharged through the PORV after the steam in the pressurizer had been relieved.

A review of the PRT parameters (Figure 4.6-26) indicates that the four percent level increase during the PORV openings corresponds to approximately 40 ft^3 of water. Since the mass of steam in the pressurizer at 10:07 a.m. corresponds to 35 ft^3 of water at 1400°F, the indicated increase in PRT level implies that only 5 ft^3 of water was discharged through the PORV.

Therefore, all the available data indicated that when the PORV failed to close it was discharging steam; that very little liquid discharge took place; and that the liquid discharge occurred at the end of the blow down while the PORV block valve was closing.

During the time when the PORV was open, the indicated cold-leg temperature in the B RCS loop decreased rapidly to 260°F and then recovered to 350°F. These changes are associated with an increase and decrease in SI flow in the B loop cold leg. The SI water was mixing with the hot water from the reactor vessel downcomer and the B loop cold-leg temperature sensor was reading a mixed fluid temperature.

After the pressurizer PORV block valve was closed, the system pressure returned to approximately 1400 psig. This pressure was slightly higher than the pressure recorded before the PORV openings. Except for forming the steam bubble in the upper head and filling the pressurizer with water, the system conditions after the block valve closure were essentially the same as before the PORV opening.

After the operator noted that the PORV block valve indicated closed on the main control board, he directed that the PORV tailpipe temperatures be monitored to insure that the block valve had fully closed and that the other PORV was not leaking. The drop in tailpipe temperature was slower than expected, so the operator closed the block valve associated with the other PORV. It was later determined that there was no leakage past the originally closed block valve or the second PORV.

Throughout this phase of the event, the RCS was being cooled by dumping steam from the A SG to the main condenser. Auxiliary feedwater for the A SG was supplied by the A motor-driven pump from the condensate storage tank.

Instrument air had been restored at 9:59 a.m., but the selected letdown orifice isolation valve (LCV-200B) and level control valve (LCV-427) remained closed because the pressurizer level was below 10%. At approximately 10:08 a.m., the pressurizer level increased above 10%, opening (LCV-427) and the selected orifice isolation valve as designed. The letdown containment isolation valve (AOV-371) remained closed, since the valve does not automatically open when the containment isolation signal is reset. Consequently, the letdown line was communicating with the RCS while the downstream portion of the letdown line remained isolated, and the relief valve opened at a set pressure of 600 psig. This valve relieves to the PRT and was a major contributor to the PRT level increase.

4.6.3.5 Event Phase 5: Prolonged Safety Injection (10:15 a.m. to 10:38 a.m.)

When the RCS pressure and the pressurizer level increased after the PORV block valve was closed at 10:11 a.m., the conditions necessary for allowing termination of SI existed. The plant operators knew; however, that a steam bubble had formed under the reactor vessel upper head and they were reluctant to interpret the high pressurizer level as a legitimate indication of having sufficient RCS inventory. As a result, the termination of SI did not occur until about 10:38 a.m., after discussions were held between control room personnel and the Technical Support Center personnel.

A detailed review of the system data indicate that PORV operation was successful in decreasing RCS pressure and in increasing the liquid inventory by SI and charging flow. Subsequently, SI increased RCS pressure to 1390 psig. SI flow could have been safely terminated immediately after the PORV block valve closed at 10:11 a.m.

After 10:11 a.m. the continued SI caused the RCS pressure to remain approximately 300 psi above the B SG pressure. This pressure differential caused the leakage to the SG to persist. As a direct result of the leakage into the B SG, the pressure increased to 1080 psig at 10:19 a.m., and the opening of a SG safety valve released steam into the atmosphere. This occurred again at 10:28 a.m. The first and second SG safety valve openings each resulted in pressure reductions of approximately 50 psi. The A and B SG valve position recorders were started by a technician earlier in the event, but the recorders failed to indicate these and subsequent valve lifts.

The repeated openings of the SG safety valve led the control room and Technical Support Center personnel to decide to terminate SI.

4.6.3.6 Event Phase 6: Safety Injection Termination and Leakage Reduction (10:38 a.m. to 11:21 a.m.)

The SI pumps were stopped at 10:38 a.m. and the RCS pressure decreased to approximately 950 psig. The secondary pressure continued to decrease to approximately 850 psig as a result of the third opening of the SG safety valve. This SG pressure reduction of approximately 200 psi is unusually large and indicates that this valve did not close normally, possibly as a result of discharging two-phase flow. With an RCS-to-SG ΔP of 100 psi, the leak rate was reduced to approximately 150 gpm. As a result of the continuing leakage, the pressure difference between the RCS and the B SG gradually decreased over the next 40 minutes, falling to 30 psi at about 11:19 a.m.

At about 10:40 a.m. the pressurizer heaters were re-energized to establish a steam bubble in the pressurizer. The pressurizer heaters had tripped on low pressurizer level during the initial depressurization.

At about 10:42 a.m., a second charging pump was started. As indicated in Figure 4.6-25, the equilibrium RCS pressure was approximately 40 psig above the pressure in the B SG with the two charging pumps running. Continued charging flow while letdown remained isolated caused the RCS-to-SG pressure differential to persist and the break flow to continue.

During this phase of the event, the method of dumping steam from the A SG was changed to allow steam to be vented to atmosphere through the atmospheric PORV on the A SG. The steam had been dumped to the condenser until the last operating condensate pump was secured at 10:40 a.m. Without condensate flow, the air ejector automatically secured, and the vacuum in the condenser was not maintained. The decision to stop dumping steam to the condenser was made to prevent any further contamination of the condensate system, particularly the condensate demineralizers.

Also, during this phase of the event, the RCS pressure increased from 950 to 1050 psig. Initially the increase was caused by operators throttling closed the A SG PORV with a corresponding decrease in heat removal from the RCS. After 11:07 a.m., when one of the SI pumps was restarted, the RCS pressure increased when the SI pump added water. The SI pump had been restarted as a precaution against a large pressure reduction which could be caused by the restart of the A reactor coolant pump.

One B SG safety valve opened a fourth time as a result of the RCS pressure increase caused by the operation of the SI pump.

During this phase, both the letdown line relief valve and the seal return relief valve continued to lift and discharge water to the PRT. As shown in Figure 4.6-26, the PRT water level increase indicates that the letdown relief valve was the major contributor to the tank inventory increase, which resulted in the burst of the tank rupture disc at about 10:52 a.m. The letdown relief valve remained open until 12:02 p.m. The estimated flow rate through the letdown relief valve was about 24 gpm based on the rate of change in PRT level indication between 10:15 and 10:45 a.m., 22 gpm based on PRT and containment sump inventory balance.

4.6.3.7 Event Phase 7: Reactor Coolant Pump Restart (11:21 a.m. to 11:37 a.m.)

This phase of the event began with the restart of the A RCP at 11:21 a.m. No detailed information is available for the period immediately before or immediately after the time when the pump was restarted because of computer failure.

Although there is no computer recorded data for the period during the pump restart, later computer data (about 12 minutes after pump restart) and hand written logs of the thermocouple data indicated that the temperature reduction in the upper head region was very rapid and occurred very soon after the restart of the RCP. All the data after the time of pump restart showed that, with the exception of the pressurizer, the entire RCS was at approximately the same temperature for the rest of the event.

The reactor vessel upper head temperatures had been below the saturation temperature corresponding to the RCS pressure since 10:11 a.m. but were significantly higher than the temperatures in the remainder of the RCS, with the exception of the pressurizer. At 11:21 a.m., a steam bubble of less than 300 ft^3 may still have existed in the upper portion of the reactor vessel. There is no instrumentation at higher elevations which would detect such a bubble. After the RCP restart the indicated temperature in the upper head decreased to a value equal to the temperature in the remainder of the RCS, approximately 400°F. With the RCP running and more than 100°F of subcooling at the upper head thermocouple locations, it is unlikely that any steam existed in the upper head at this time or later.

The limited data available indicate that it is likely that a small RCS-to-SG differential pressure, perhaps 40 psid, existed throughout this period. The corresponding leak rate would be 100 gpm.

Throughout this phase of the event, one SI pump was operated as a precaution against an uncontrolled depressurization associated with the RCP restart. Such a depressurization was of concern to the plant staff because the pressurizer level was still off scale and a steam bubble was thought to exist in the reactor vessel upper head. It should be noted that the B SG would have provided water through the ruptured tube to help suppress any large pressure changes. The primary results of operating the SI pump were the two additional openings of the B SG safety valve. These openings of the valve will be discussed further in the next phase of the event. The depressurization associated with the RCP restart was limited to about 100 psi, apparently as a result of steam formation in the pressurizer (above the range of indicated levels) and increased SI flow.

4.6.3.8 Event Phase 8: Leaking Steam Generator Safety Valve (11:37 a.m. to 12:27 p.m.)

At 11:37 a.m., the B SG's safety valve opened for the fifth time, as a result of the continuing SI. The data indicated that the valve did not close until pressure in the SG decreased to 840 psig. This value is about the same as that for one of the earlier valve openings and is considerably below the pressure at which the valve would normally close. This abnormal behavior may again be attributed to the fact that the valve discharged liquid rather that the steam for which it had been designed.

After the B SG safety valve closed, the pressure differential between the RCS and the B SG was more than 100 psid.

Safety injection flow was terminated at about the same time as this last valve opened. However, the RCS to SG differential pressure was significantly higher than for the comparable conditions at 10:38 a.m. Three additional facts indicate that this phase is significantly different from earlier phases of the event. First, the reduction in B SG pressure at approximately 12:05 p.m., while the RCS pressure was more than 100 psi higher, cannot be explained unless there was significant mass or energy removal from the SG. Cooling of the B SG was in progress at this time; however, the observed rate would not support such a pressure difference. Second, the indicated differential pressure implies a large flow, estimated to be 100 to 200 gpm, into the SG over a long period of time (50 min.). Since the B SG appears to have been full at 11:37 a.m. (the time of the last valve opening), it appears very unlikely that the SG could accommodate an additional 5,000 to 10,000 gallons of water. Third, the rapid increase in B SG pressure at about 12:25 p.m. was similar to that experienced when the safety valve closed earlier in the event. These facts tend to conclude that it is very likely that the B SG safety valve failed to fully reseat following the opening at 11:37 p.m. and that the valve leaked at a rate of 100 to 200 gpm for approximately 50 min. This release rate is approximately two to four percent of the valve capacity and was probably not noticed by the plant staff because its noise and steam discharge were masked by the noise and steam from the nearby A SG atmospheric PORV. The mass balance also tends to support the position that the safety valve failed to properly reseat for 50 min.

At 11:52 a.m., the pressurizer level indication came back on scale. The estimated rate of leakage through the B SG safety valve and the continued plant cooldown would explain the return of the pressurizer level during the period when charging flow exceeded letdown. The maximum rate of decrease of the indicated pressurizer level agreed well with that predicted by calculations. Normal letdown had been restored at about 12:02 p.m. At about 12:12 p.m., one SI pump was restarted, apparently for the purpose of arresting the decrease in pressurizer level caused by continuing leak into the B SG. The SI pump was then operated intermittently to control pressurizer level throughout the remainder of this phase.

4.6.3.9 Event Phase 9: Leak Termination and Cooldown (12:27 p.m., 1/25/82 to 10:45 a.m., 1/26/82)

At about 12:25 p.m., the B SG safety valve appears to have seated. The SG indicated pressure then increased to a value slightly above the RCS pressure, and the RCS leak was terminated. At about 12:35 p.m., the SI pump was stopped; it was no longer needed to control pressurizer level.

The break flow was controlled by attempting to maintain the RCS pressure at about 25 psi below the B SG pressure during the RCS cooldown and depressurization. The B SG was, therefore, leaking water back into the RCS during this phase of the event. The B SG cooldown was being controlled by the heat transfer from it to the RCS.

After 12:27 p.m., the cooldown proceeded at a very slow rate, which allowed time for the RCS to be degassed before using the RHR system (the low pressure and low temperature decay heat removal system). During this phase of the event, the B SG water level indication came back on scale on the narrow-range instrument at approximately 6:40 p.m., January 25, 1982.

Estimated break flow for an indicated 25 psi differential pressure was calculated and found to be about four times larger than that expected based upon the rate of level decrease observed in the B SG. The rate of change of the B SG wide range water level indicating implies a 37 gpm leak rate. The return from being off-scale after seven hours of leakage back into the RCS implies approximately a 39 gpm leak rate. Considering the limited data available, these values are considered to be in good agreement.

Since the B SG pressure sensor is at an elevation approximately 60 ft above the elevation of the pressure sensor in the RCS loop and the SG was flooded with water, the actual pressure differential at the break would have been 28 psi greater than indicated. Therefore, an indicated SG pressure 25 psi greater than the RCS pressure would mean a break differential pressure of 53 psi, which would have supported a much larger leak rate of approximately 150 gpm. For the leak rate to have averaged 36 gpm, the pressure difference must have been less than three psi. After reviewing the reactor coolant loop pressure measurements and all three B SG pressure measurements for the cooldown phase, particularly the pressure oscillations occurring between 8:00 p.m. and 11:00 p.m., January 25 (see Figure 4.62-7), the reactor coolant loop pressure measurement was in error (too low) by approximately 50 psi. This error was recognized by the plant staff sometime during this phase and may have existed throughout the entire event, since a similar bias can be seen in the data at 9:26 a.m. An error of this magnitude is not surprising in a pressure instrument with a range of 0 to 3000 psig. (NOTE: A normal pressure instrument accuracy specification is one percent of full scale, which for this instrument is 30 psi).

The fact that the B SG pressure did not decrease to the saturation pressure corresponding to the temperature of the water being pumped through the SG tubes, indicates that thermal stratification existed in the generator and its attached main steam line. Thermal stratification is to be expected in a steam system which has been over filled, particularly for a design like that of Ginna in which the upper internals impede water volume communication and the steam line slopes downward toward the turbine and allows hot water to be trapped. This information, together with the information on the leak rate, indicates that the primary reasons for the slow depressurization of the B SG were (1) the extremely small pressure differential between the RCS and B SG, and (2) the thermal stratification of the water in the SG, which prevented complete cooling.

After 12:25 p.m., January 25 the flow through the ruptured tube was from the B SG into the RCS. Under this condition, there is concern for potential dilution of the boric acid in the RCS. The boron concentrations in the B SG and the RCS were checked before cooldown and depressurization began and at approximately half-hour intervals thereafter. The B SG samples indicated 1100 ppm boron. Because of the amount of boric acid injected into the RCS from the boric acid storage tanks and refueling water storage tank, there was never any potential for an inadvertent criticality (the boron concentration needed to maintain the required shutdown margin was approximately 700 ppm) because of boron dilution during this event.

At approximately 6:40 p.m., the B SG narrow-range water level indication was on-scale, and auxiliary feedwater was supplied for the first time since 9:32 a.m. This was done to assist in the cooldown of the B S/G and helped to degas it.

When the B SG was depressurized, a gas mixture was found that included hydrogen and gaseous fission products, such as xenon, both of which are normally found in the RCS. Some fission products are always found in PWRs. The presence of these non-condensable gases may have also contributed to the slow depressurization of the SG.

The RHR system was placed in service at about 7:00 a.m. on January 26, 1982. The plant staff chose to maintain system conditions without substantial RCS cooldown while the RCS was cleaned and degassed using the CVCS at a letdown rate of 50 to 60 gpm.

TABLE 4.6-1 TYPICAL SEQUENCE OF AUTOMATIC ACTIONS FOLLOWING A DOUBLE-ENDED SGTR

	TIME (sec)	
EVENT/SIGNAL	OFFSITE POWER	NO OFFSITE POWER
Tube Failure	0	0
Reactor Trip Signal	232	232
Loss of All A/C Power	—	232
Steam Dump Operation	233	—
Turbine Isolation	234	234
Safety Valve Operation	—	245
SI Signal	250	386
Main FW Isolation	257	393
AFW Actuation	310	446*

* AFW actuation may occur coincident with loss of offsite power. For a typical 4-loop plant, only the turbine-driven pump would start at that time. The motor-driven pumps would be loaded on the emergency diesels after SI actuation.

TABLE 4.6-2　GINNA System Parameters

Parameter	Value	Parameter	Value
General:		Auxiliary Feedwater:	
Licensed power	1520 MWt	Motor-driven	2
Plant capacity	490 MWe	capacity	200 gpm(ea)
Number of loops	2	start signals	lo-lo S/G level
Loop isolation valves	none		trip MF pumps
			SIS
Steam Generators:		Turbine-driven	1
Secondary water volume:		capacity	400 gpm
full load	1681 cu ft	start signals	lo-lo level (both
no load	2821 cu ft		S/G's)
Level at full load	52 %		Loss of Power
no load	39 %		(both 4kVbuses)
Secondary Steam Volume:			
full load	2898 cu ft	Standby AFW System	Manual
no load	1758 cu ft		
A S/G to MSIV	776 cu ft	MSIV Automatic Closure	
B S/G to MSIV	1055 cu ft	Modes All Lines:	
Steam Pressure at full load	755 psig	(1) High-high steam flow,	
no load	1055 psig	and SIS	3.6E6 lb/h
Primary water volume	944 cu ft	(2) High steam flow, low	
U-tubes per S/G	3260	Tavg and SIS	0.4E6 lb/h
Allowed leakage	0.1 gpm	(3) High Containment	
S/G safety valves	4	Pressure	18.0 psig
setpoints	1085 psig		
3 at	1140 psig	MSIV closure time	1.0 sec.
Flow rate each S/G	3.3E6 lb/h		
at 1100 psig	0.82E6 lb/h	Charging System:	
PORV's each S/G	1	Number of pumps	3
operation	auto at > 1050	Type	Pos. Disp.
	psig or manual	Design flow ea.	60 gpm
capacity	10 % power	Normal Charging Flow	30 gpm
		Normal Letdown Flow	40 gpm
Steam Dump Bypass:		Normal RCP seal supply	16 gpm
modes	T_{avg}-T_{ref}	Normal RCP seal return	6 gpm
	Steam Pressure	Automatic letdown isolation	Low Pzr Pressure
capacity	40 %	Automatic Trip	Safety Injection

TABLE 4.6-2 GINNA System Parameters (Continued)

Parameter	Value
Reactor Coolant System:	
Total Volume	6245 cu ft
Total RCS Flow	64.3E6 lb/h
RCP thermal output	30E6 btu/h
Tavg at full load	573°F
no load	547°F
Reactor vessel head temp.	590°F
Nominal system pressure	2200 psig
low pressure scram Setpoint	1873 psig
Pressurizer:	
Total Volume	800 cu ft
Water volume @ full load	480 cu ft
Total heater Capacity	800 kW
Spray nozzle ΔT Limit	320°F
Pressurizer PORV's	
Number	2
Set pressure	2335 psig
Flow rate	1.79E6 lb/h
Pressurizer Relief Tank	
Rupture Disc Design	100 psig
Capacity	800 cu ft
Pressurizer Safety Valves	
Number	2
Operating Pressure	2485 psig
Flow rate @ 2500 psig	0.228E6 lb/h
Pressurizer Level	
Full Load	47 %
No Load	22 %
Safety Injection Actuation Setpoints	
Low Pressurizer Pressure	1723 psig
High Containment Pressure	4 psig
Low Steamline Pressure	514 psig

Parameter	Value
High Pressure Safety Injection	
Number of pumps	2
Type	Centrifugal
Design flow	300 gpm
Shut-off pressure	1520 psig
Boron Injection with SIS	Initially from BAST then RWST
Accumulators	
Number	2
Pressure	700 psig
Refueling Water Storage Tank	
Capacity	3.38E5 gal
Boron concentration	>2000 ppm
Design Pressure	121 psig
Boric Acid Storage Tank	
Number	2
Capacity, ea	3600 gal
Boron concentration	20,000 ppm
Main Feedwater Pumps	
Number	2
Type	Centrifugal
Capacity, ea	50% of FP
Flow rate, ea	14,000 gpm
Operating pressure	853 psig
Shut-off head	1180 psig
Drives	Electric
Isolation Signals	
S/G high level	67 %
SIS	
Trips	
1. Loss of Offsite Power	
2. Overcurrent	
3. Thermal Reload	

TABLE 4.6-3	GINNA Event Chronology
Time and Event	Comment
January 25, 1982	
9:22 a.m.	
Initial conditions: plant power, 100%; indicated reactor coolant system (RCS) loop pressure, 2197 psig; indicated RCS loop average temperature, 572°F; indicated pressurizer pressure, 2235 psig; other primary secondary parameters normal; primary-to-secondary leak rate, 0 gpm.	The primary-to-secondary leak rate was last calculated based on air ejector monitor indications on January 7, 1982. Air ejector radiation monitor indications had been essentially constant since January 24, 1982. No known plant operations that would have caused or affected the event were in progress.
9:25 a.m.	
The following alarms were received in the control room: charging pump speed alarm; B steam generator level deviation alarm; B steam generator steam-flow/feed-flow mismatch alarm; pressurizer level and pressure deviation alarms; air ejector radiation monitor (R-15) alarm; pressurizer low pressure alarm (Setpoint, 2185 psig).	First indications of the tube rupture in B steam generator. One charging pump, which was in automatic pressurizer level control, was now at its maximum speed. The speed of a second charging pump, which had been on manual control, was increased by the operator. The third charging pump was not operating.
9:26 a.m.	
The Shift Supervisor ordered power reduction. One operator fast closed the turbine control valves; another operator commenced normal boration.	The Shift Supervisor was initially in his office which was located off the main operating area of the control room. He was called to the control room by an operator after the first alarm annunciated.
The following alarms were received in the control room: reactor coolant loop low pressure alarm (setpoint, 2064 psig); over temperature DT turbine runback because of decreasing pressurizer pressure; main steam dumps armed alarm.	The over temperature ΔT Setpoint is a computed value which is a function of pressurizer pressure and reactor coolant system average temperature.
9:27 a.m. (about)	
All eight main steam dump valves opened automatically.	Steam dump valves opened in automatic control in response to error signal derived from the difference between RCS coolant reference and average temperature.
The third charging pump was manually started by the operator.	All three charging pumps were running at this time. The RCS pressure and pressurizer level decreased as a result of flow through the rupture (break flow). The rate of indicated decrease was consistent with the break flow and the combined effects of high charging flow and the RCS swell from the turbine down-power transient.

TABLE 4.6-3	GINNA Event Chronology (continued)
Time and Event	Comment
The containment fan-cooler, service-water discharge radiation monitor (R-16) alarmed.	Alarm probably resulted from the proximity of the instrument to the B main steam line in the Intermediate Building.
9:28 a.m.	
Four main steam dump valves closed automatically.	
The following also occurred: pressurizer level low alarm (Setpoint, 10.5%); automatic reactor trip on low pressurizer pressure (Setpoint 1873 psig adjusted by a rate factor); automatic safety injection as a result of safety injection actuation; main turbine automatic trip on reactor trip; A and B steam generator low level alarms; automatic start of both A and B motor-driven auxiliary feed pumps on safety injection; main feedwater automatic isolation and main feedwater pump automatic trip on containment isolation.	The steam generator low levels resulted from the combined effects of the power reduction, reactor, main turbine and main feedwater pump trips. The RCS depressurization rate increased at this time. The break flow had not increased, but the effects of increasing RCS temperature due to the turbine load reduction were no longer present. Further, all charging pumps automatically tripped as a result of safety injection actuation. Letdown isolation valve LCV427 closed on low pressurizer level; the In-service orifice isolation valve closed on interlock with LCV472 controls. The reactor coolant pump (RCP) seal return line isolated on containment isolation. Leakage through the RCP seals pressurized the seal return piping. As shown by pressurizer relief tank (PRT) level indication, the seal return relief lifted. The contribution of this relief to PRT inventory was insignificant.
9:29 a.m.	
The main electrical generator output breakers automatically tripped.	
Both RCPs were manually tripped.	Ginna Emergency Procedures E-1.1 and E-1.4 require tripping RCPs at <1715 psig; Westinghouse Owners' Group guidance recommends a lower trip pressure. Licensee requires an RCP trip at a higher pressure because Ginna lacks an environmentally qualified pressure instrument capable of reading these lower pressures.
Pressurizer level indicated about 0%.	

TABLE 4.6-3	GINNA Event Chronology (continued)
Time and Event	Comment
9:29 a.m. (about)	
Both steam supply valves to the turbine-driven auxiliary feedwater pump opened automatically because of low-low lwvwl in bith steam generators.	
9:30 a.m.	
Four main steam dump valves closed automatically.	All steam dumps were now closed.
Initial RCS depressurization stopped at about 1200 psig.	Based on post-event data evaluation, the Task Force concluded a steam bubble may have formed in the reactor vessel upper head at this time. Termination of pressure drop was apparently due to the effects of the establishment of saturation conditions in the reactor vessel upper head along with safety injection.
9:32 a.m. (about)	
The B motor-driven auxiliary feedwater pump was secured manually.	
The B steam supply valve to the turbine-driven auxiliary feedwater pump was closed manually.	The turbine-driven auxiliary feedwater pump was now being supplied steam from the A steam generator only.
9:33 a.m.	
The Shift Supervisor notified the NRC Operations Center via the Emergency Notification System (ENS) phone. The Shift Supervisor reported a reactor trip from 100% power as a result of a steam generator tube rupture. The identity of the faulted steam generator and release information was not given at this time.	The Shift Supervisor made the ENS report using the ENS phone in his office. He suspected that the B steam generator contained the fault but chose to confirm the situation before identifying the faulted steam generator to the NRC. After the initial report, a licensed reactor operator, who was not part of the on-shift crew, manned the ENS in the control room.
The Shift Supervisor declared an Unusual Event.	The Shift Supervisor declared the Unusual Event during his discussion with the NRC Headquarters Duty Officer; the Plant Superintendent was unaware of this declaration. The declaration of an Unusual Event was made in accordance with the Ginna Emergency Plan Implementing Procedures.

TABLE 4.6-3	GINNA Event Chronology (continued)
Time and Event	Comment
9:38 a.m.	
Various main steam dump valves began to cycle open and closed.	Main steam dump valves were now being operated in the pressure-control mode. The operator was manually controlling these valves to cause a plant cooldown as required by the steam generator tube rupture procedure.
9:40 a.m.	
The B main steam isolation valve (MSIV) was manually closed and the B steam generator was isolated as required by the steam generator tube rupture (SGTR) procedure. Plant cooldown was being maintained by dumping steam from A steam generator to the main condenser.	Along with closing the MSIV, B steam generator isolation included automatic closure of the feedwater supply, blow down and sample valves on containment isolation, manual closure of its auxiliary feedwater supply, and manual closure of the steam supply valve from B steam generator to the turbine-driven auxiliary feedwater pump. RCS pressure and reactor vessel upper head temperature data indicated that the steam bubble in the reactor vessel upper head had been essentially collapsed by safety injection flow.
The licensee declared an Alert.	
9:46 a.m.	
The A steam supply valve to the turbine-driven auxiliary feedwater pump was closed manually.	The turbine-driven auxiliary feedwater pump was now secured.
9:48 a.m.	
The A motor-driven auxiliary feedwater pump was manually stopped to control A steam generator level.	No feedwater pumps were operating at this time.
9:50 a.m.	
The steam generator blow down radiation monitor (R-19) alarmed.	R-19 monitors radiation levels on a section of the blow down system piping common to both A and B steam generators. The alarm at this time may have been caused by activity from the B steam generator spreading through the system because of steam generator sample valves that the licensee indicated had a history of leaking.

TABLE 4.6-3	GINNA Event Chronology (continued)
Time and Event	Comment
9:53 a.m. The B steam generator power-operated relief valve (PORV) was manually isolated by an auxiliary operator closing a local, upstream, manual valve.	Operators stated that they manually isolated the B steam generator atmospheric PORV to minimize the potential for a release that would result from high steam generator pressure lifting the PORV. The control room operators interpreted the step in the tube rupture procedure which directed them to place the PORV in the manual closed position to mean that the local manual PORV isolation valve should be closed. Closing this isolation valve made the PORV unavailable for use in reducing B steam generator pressure and resulted in five challenges to an unisolable steam generator safety valve.
9:55 a.m. B steam generator narrow-range level indicated off-scale high even though all feedwater supplies to the B steam generator had been isolated earlier in the event.	
9:57 a.m. Safety injection initiation circuitry was manually reset; containment isolation was then reset.	Safety injection was reset to permit resetting of the containment isolation signal. Containment isolation was reset to permit restoration of instrument air to the containment. Instrument air would be required to operate various valves inside containment, including the pressurizer power-operated relief valves.
9:59 a.m. (about) Instrument air was restored to containment.	Because letdown isolation valve LCV427 fails open on loss of instrument air pressure, it could have opened subsequent to containment isolation. If LCV427 had opened, restoration of instrument air would have caused it to close at this time.
10:00 a.m. A and C condensate pumps were manually stopped.	The B condensate pump was still running.
10:03 a.m. All main steam dump valves were now closed.	
10:04 a.m. One charging pump was manually restarted.	
10:07 a.m. As directed by the SGTR procedure, pressurizer PORV PCV430 controls were manually cycled open and closed twice from the control room. RCS pressure, PRT pressure, level and temperature and PORV valve position indication in the control room demonstrated the valve successfully operated.	Shortly after the PORV was operated, pressurizer level increased above the letdown isolation Setpoint. Letdown isolation valve LCV427 and the selected letdown orifice isolation valve then opened. This resulting in lifting the letdown relief valve and adding water to the PRT. The Task Force determined the letdown relief valve was the major contributor to the PRT water level increase

TABLE 4.6-3	GINNA Event Chronology (continued)
<u>Time and Event</u>	<u>Comment</u>
10:08 a.m.	
Pressurizer PORV PCV430 controls were manually cycled again from the control room and the valve successfully operated.	
10:09 a.m.	
Pressurizer PORV PCV430 controls were manually cycled again. The valve opened as desired. After the operator placed the controls in the closed position, the valve started to close but then reopened and stuck open.	The rapid rise in pressurizer level exceeded that attributable to safety injection and charging flow and was the first clear indication to the control room staff that a steam bubble had formed in the reactor vessel upper head. This was, in fact, the second time a steam bubble had formed in the upper head region. The bubble grew as RCS pressure dropped.
The operator placed the PORV block valve control switch in the closed position. RCS pressure dropped to about 900 psig; pressurizer level increased rapidly.	
The pressurizer relief tank (PRT) high-pressure alarm was received in the control room.	
10:10 a.m.	
The PRT high-temperature alarm was received in the control room.	
10:11 a.m.	
PORV block valve PCV516 indicated fully closed; pressurizer level indicated off-scale high; safety injection increased RCS pressure.	Operator also closed block valve PCV515 to isolate the other pressurizer PORV, PCV431C.
10:17 a.m.	
The A motor-driven auxiliary feedwater pump was manually started to feed the A steam generator.	

TABLE 4.6-3	GINNA Event Chronology (continued)
Time and Event	Comment
10:19 a.m. (about)	
One B steam generator safety valve lifted and closed.	Safety injection and charging flow maintained RCS pressure greater than B steam generator pressure, resulting in continued RCS in-leakage into the faulted steam generator. RCS pressure exceeded the lowest Setpoint of the B steam generator safety valves (nominally, 1085 psig).
10:26 a.m.	
The PRT high level alarm was received in the control room.	The B steam generator safety valve may have closed and then started to leak steam after this first opening.
10:28 a.m. (about)	
One B steam generator safety valve lifted and closed.	The B steam generator safety valve position recorder failed to indicate this or subsequent safety valve lifts. The operators heard these lifts from the control room and estimated their duration based on aural information.
10:29 a.m.	
The A motor-driven auxiliary feedwater pump was manually stopped.	
10:38 a.m. (about)	
One B steam generator safety valve lifted and closed.	
Safety injection was terminated by the operators to prevent further release through the B steam generator safety valve.	Charging flow was maintained.
10:40 a.m.	
The B condensate pump and the condensate system were secured; the air ejector secured automatically following loss of condensate flow.	The licensee secured the condensate system to minimize the spread of radioactive contamination to the condensate storage tanks (CSTs) and the condensate demineralizer system. Securing the condensate system made the main
The A steam generator PORV was manually throttled open to continue the plant cooldown by relieving the A steam generator to atmosphere.	
10:42 a.m. (about)	
A second charging pump was started.	
The pressurizer heaters were re-energized to establish a steam bubble in the pressurizer.	The pressurizer heaters tripped on low pressurizer level during the initial depressurization.

TABLE 4.6-3	GINNA Event Chronology (continued)
Time and Event	Comment
10.44 a.m.	
The licensee declared a Site Area Emergency and executed a site evacuation.	Nonessential personnel were evacuated to the licensee's training center which was downwind of the plant and within the path of the release plume.
10:52 a.m. (about)	
The PRT rupture disc ruptured, releasing water to the A containment sump.	The disc ruptured primarily because of the letdown relief flow; pressurizer PORV openings and RCP seal return relief were minor contributors to the PRT level transient which finally caused the disc rupture.
10:59 a.m.	
The A motor-driven auxiliary feedwater pump was manually started to feed the A steam generator.	From this time in the event, until the plant was cooling down on the residual heat removal system, the A motor-driven auxiliary feedwater pump was run intermittently to control A steam generator water level.
11:07 a.m. (about)	
One safety injection pump was manually restarted from the control room. The safety injection pump discharge valve was locally throttled to prevent B steam generator safety valve lifts.	The safety injection pump was started in anticipation of an RCS pressure drop that might result from restarting an RCP. This action was not required by the SGTR procedure but was taken as a direct result of the inability to reestablish normal pressurizer pressure control.
11:19 a.m. (about)	
One B steam generator safety valve lifted and closed.	
The process computer failed. It remained out of service until about 11:35 a.m.	The licensee manually read reactor vessel upper head and core exist thermocouples to verify adequate core cooling and to determine subcooling in the core and reactor vessel upper head. Any remaining steam bubble in the reactor vessel upper head region, at this time, would have had a volume of less than 300 ft3.
11:21 a.m. (about)	
The A RCP was restarted; reactor vessel upper head thermocouple temperatures approached core exit temperatures; pressurizer level indications remained off-scale high. One charging pump was stopped.	A steam bubble in the reactor vessel upper head region would have been condensed by the cooler loop water now forced into this region. Since the pressurizer level instruments were calibrated for operating conditions, the actual pressurizer level would have to drop below 80% before indicated level would respond. The pressurizer volume above 80% actual level is approximately 200 ft3.

TABLE 4.6-3	GINNA Event Chronology (continued)
Time and Event	Comment
11:37 a.m. (about)	
One B steam generator safety valve lifted and closed; the safety injection pump was stopped.	Based on the indicated pressure differential between the RCS and the B steam generator, and on an RCS inventory balance calculation, the Task Force determined the safety valve failed to fully reseat. It remained partially open until about 12:25 p.m., leaking water at a rate estimated to be about 100 gpm.
11:43 a.m. (about)	
The plant vent particulate radiation monitor (R-13) and the plant iodine monitor (R-10B) alarmed.	The licensee stated that the R-13 and R-10B monitor alarms were probably caused either by increased background radiation in the vicinity of these monitors or by the Auxiliary Building ventilation system drawing outside air into the building after the steam generator safety valve lifts. It should be noted that no plant noble gas radiation monitor (r-14) alarm was received at this time. The reason this alarm did not occur has not been determined.
11:52 a.m.	
Pressurizer level indications returned on scale; a steam bubble had been reestablished in the pressurizer.	The maximum rate of change of pressurizer level indication, which occurred about 12:10 p.m., agreed well with that predicted by analysis of the effects of the existing cooldown, charging and letdown rates and the break flow predicted by the Task Force model.
12:02 p.m.	
Normal letdown was restored.	
12:12 p.m. (about)	
One safety injection pump was started from the control room.	The safety injection was restarted to terminate the rapid decrease in pressurizer level. The pump was operated intermittently over the next 23 minutes to control pressurizer level.
12:27 p.m.	
The RCS and B steam generator indicated pressures equalized.	The B steam generator pressure trend indicated that the B steam generator safety valve reseated completely just
12:34 p.m. (about)	
The RCP seal water return isolation valve was manually opened.	RCP seal return relief reseated at this time.

TABLE 4.6-2	GINNA Event Chronology (continued)
Time and Event	Comment
12:35 p.m. (about) Intermittent operation of the safety injection pump was stopped.	
1:16 p.m. The A MSIV was manually closed.	
2:00 p.m. The licensee reported containment sump A level as 9.3 feet (approx. 8000 gallons); PRT level at 92%.	Containment sump A has two channels of level indication. Channel 1 indicated 5.3 feet (1,900 gallons); channel 2 indicated 9.3 feet (8,000 gallons). Later, it was discovered that channel 2 was in error.
6:40 p.m. (about) Narrow-range water level indication for the B steam generator returned to the indicating range. Plant cooldown continued via the A steam generator PORV with the A RCP providing flow through the A loop and back flow through the B loop. The operators maintained indicated RCS pressure 25 psi below B steam generator pressure. The B steam generator was being cooled by intermittently feeding it with auxiliary feedwater while bleeding it via the ruptured tube to the RCS.	The plant staff was concerned that water in the B main steam line might flash to steam if the steam generator was cooled and depressurized too quickly. Flashing in the main steam lines could have caused a water hammer, which could have over stressed the main steam line hangers. Therefore, the plant staff decided to pin these hangers and to conduct a slow cooldown. Because of an instrument calibration error in the RCS loop pressure instrument, the actual RCS-to-B steam generator pressure differential was about 3 psi and very little steam generator-to-RCS flow existed. To provide warning of excessive boron dilution in the RCS as a result of the B steam generator feed-and-bleed process, the plant staff sampled the RCS for boron concentration at half-hour intervals. The feed-and-bleed cooldown process caused the level in the CVCS Holdup Tanks to increase and the plant staff discussed the consequences of these tanks filling. The capacity of these tanks was not approached.
7:04 p.m. An operator again attempted to shut pressurizer PORV PCV430; the valve remained open.	
7:17 p.m. The licensee downgraded the Site Area Emergency to an Alert.	

TABLE 4.6-2	GINNA Event Chronology (continued)
Time and Event	Comment
January 26, 1982	
7:00 a.m. (about)	
The residual heat removal (RHR) system was placed in service to continue the plant cooldown. The A RCP remained in operation.	The RCP remained in operation to assist in RCS degasification and cleanup in preparation for opening the primary-side man-way on B steam generator. At low steam pressures in the A steam generator, the capacity of the A steam generator PORV had limited the plant cooldown rate.
10:45 a.m.	
The licensee downgraded the Alert to the Recovery Phase.	

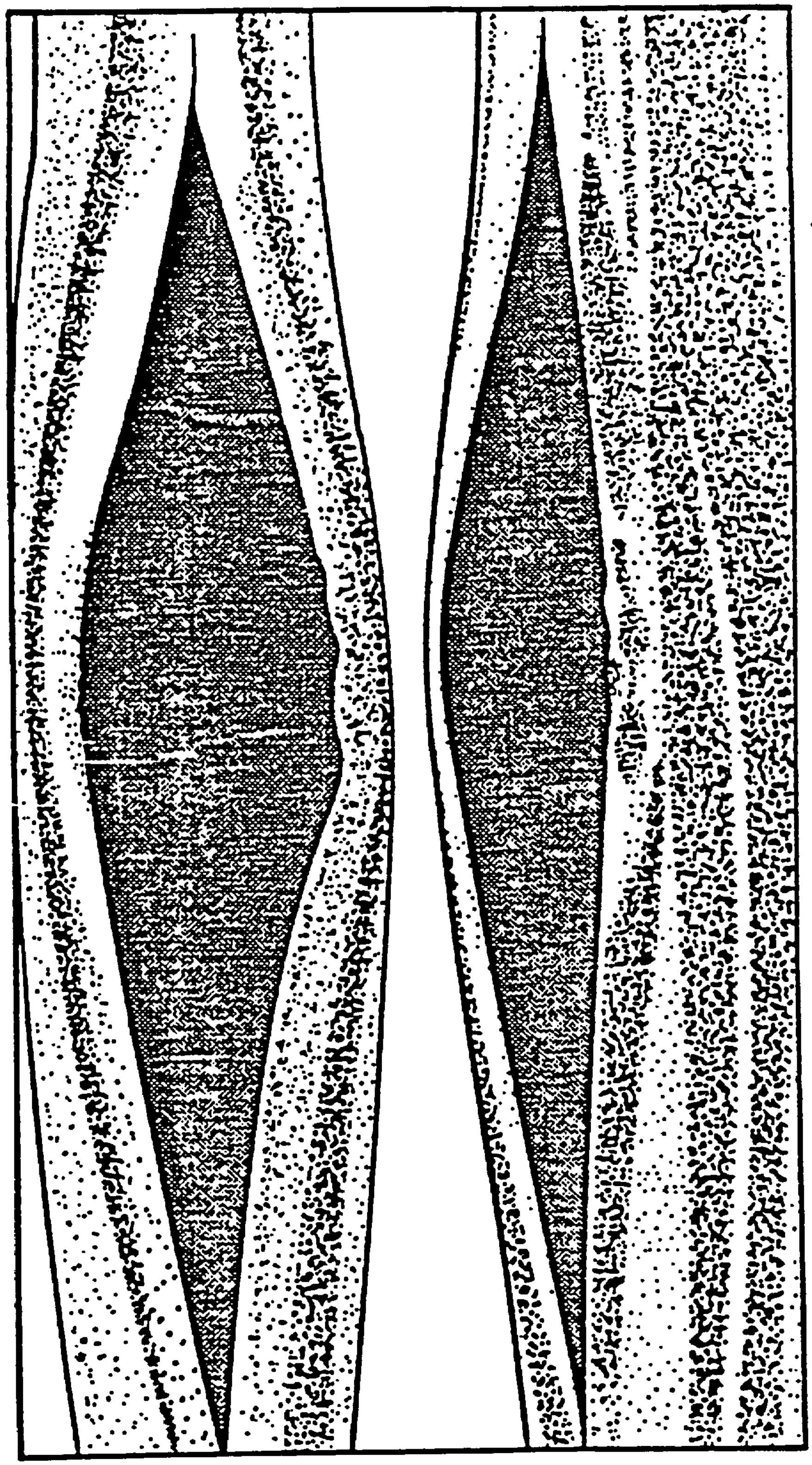
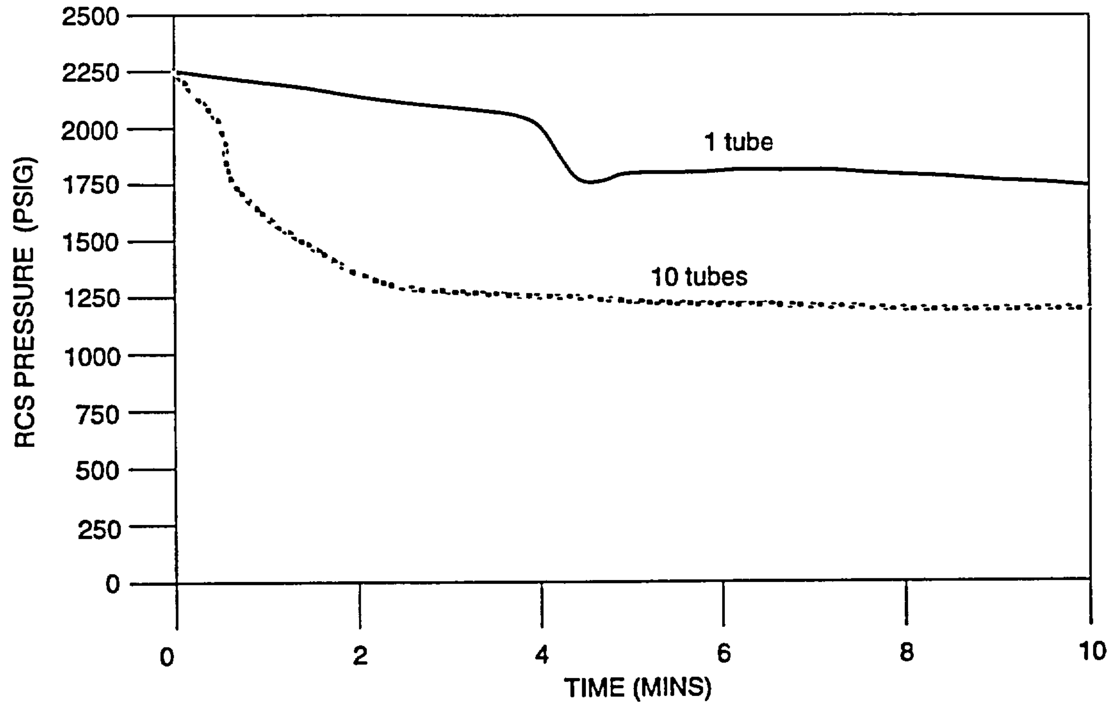


Figure 4.6-1 Closeup View of SGTR



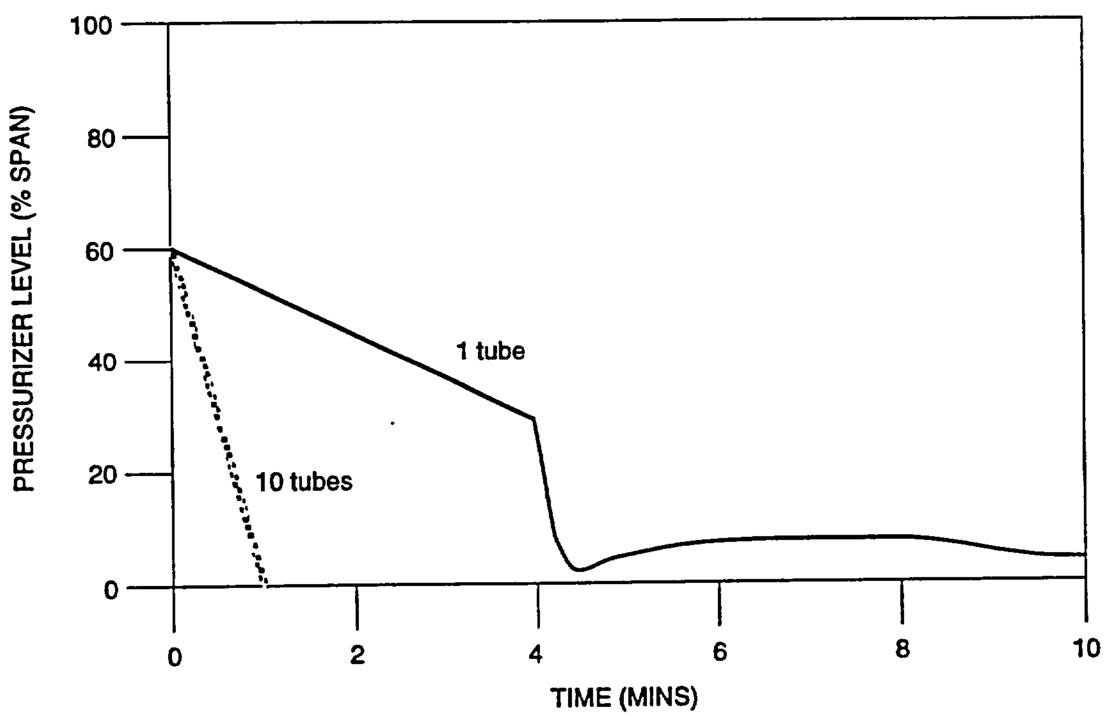


Figure 4.6-2 Initial Pressurizer Pressure and Level Response

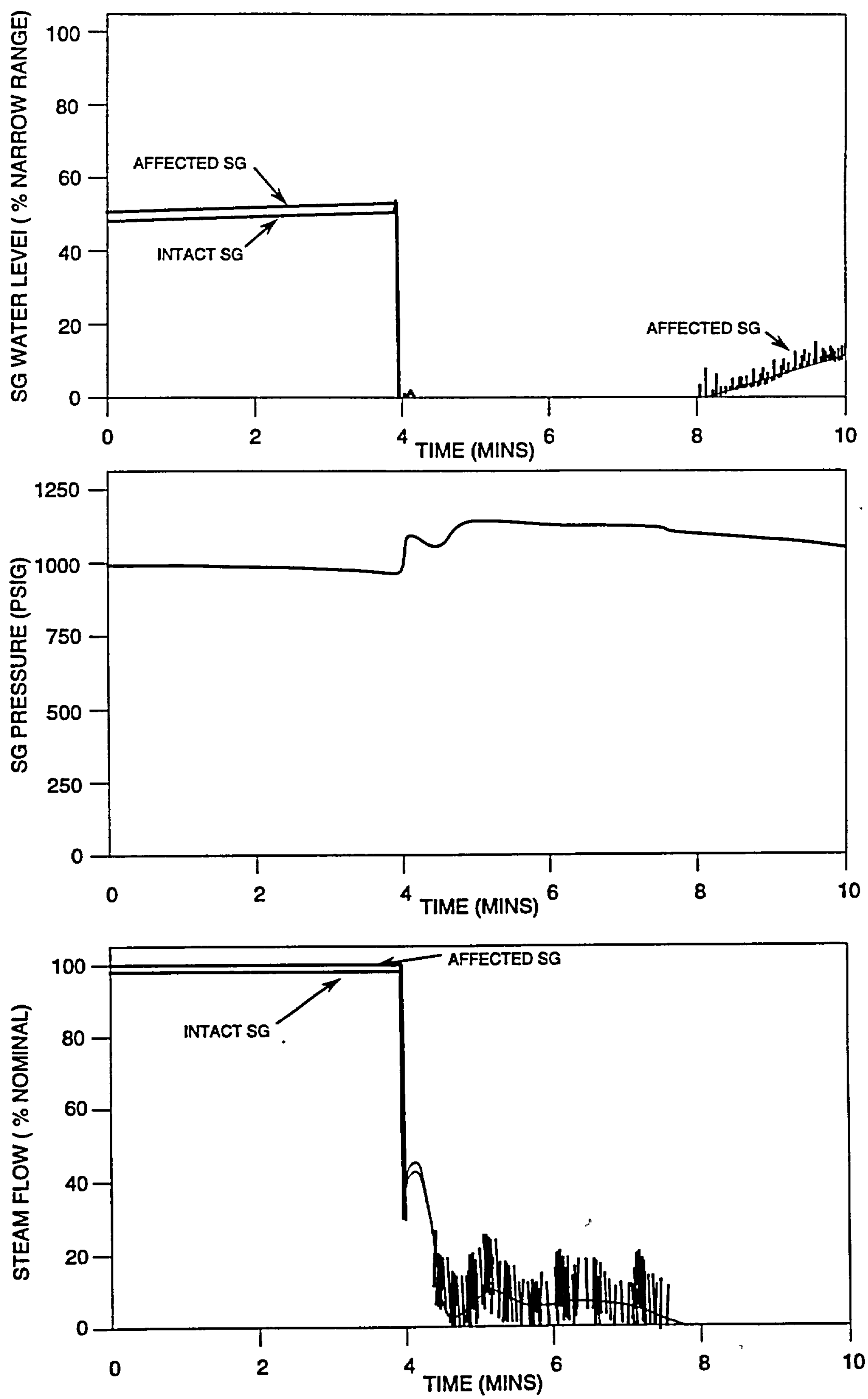


Figure 4.6-4 Steam Generator Response Following Reactor Trip

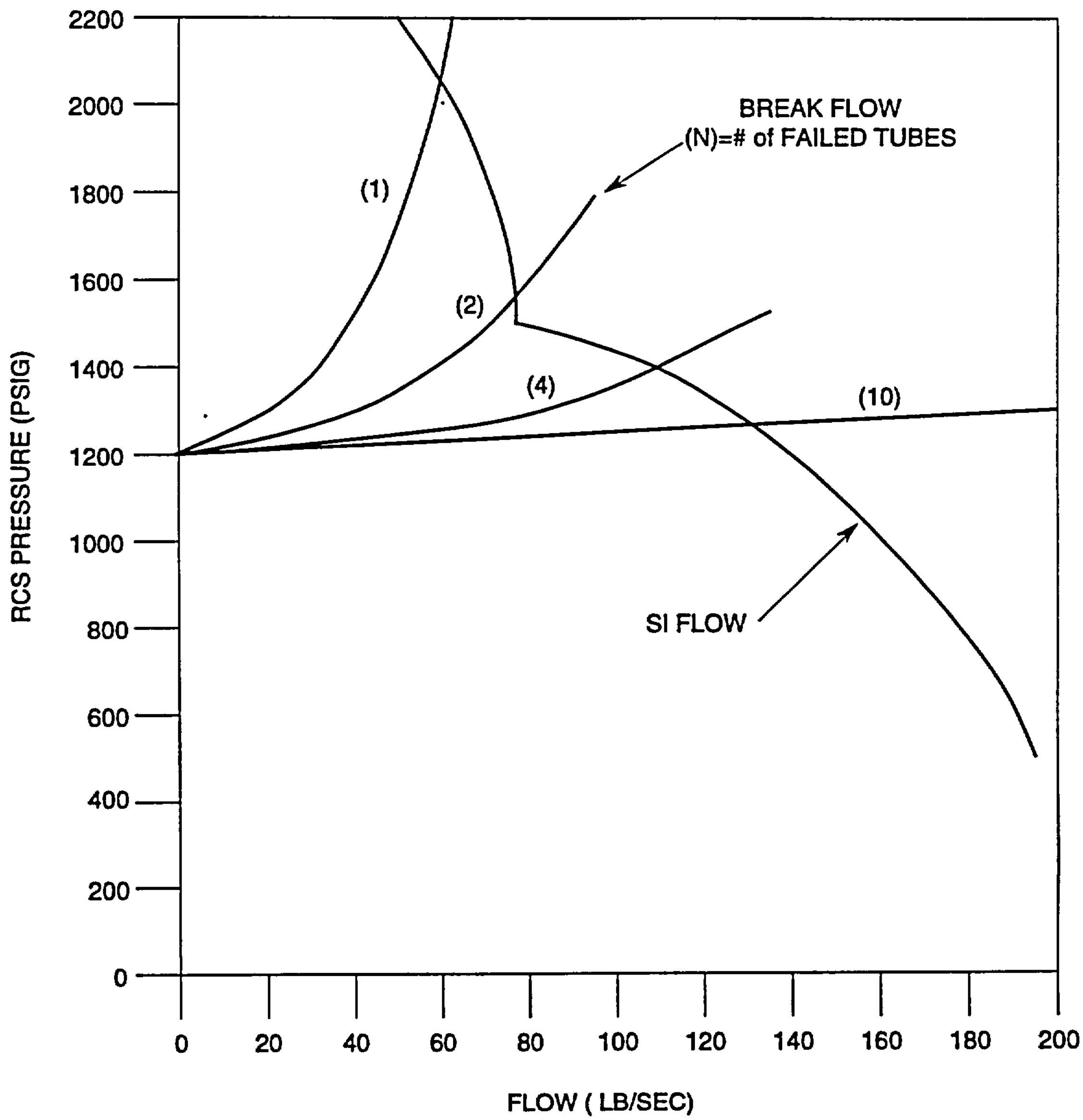
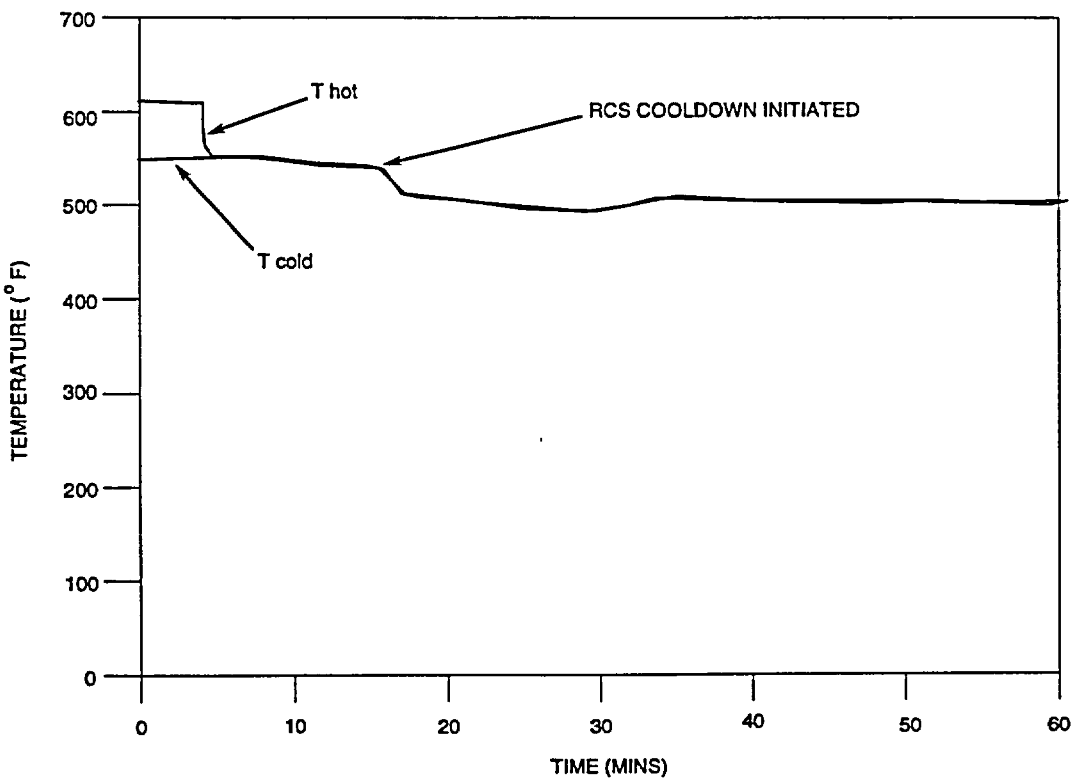


Figure 4.6-5 Equilibrium Break Flow



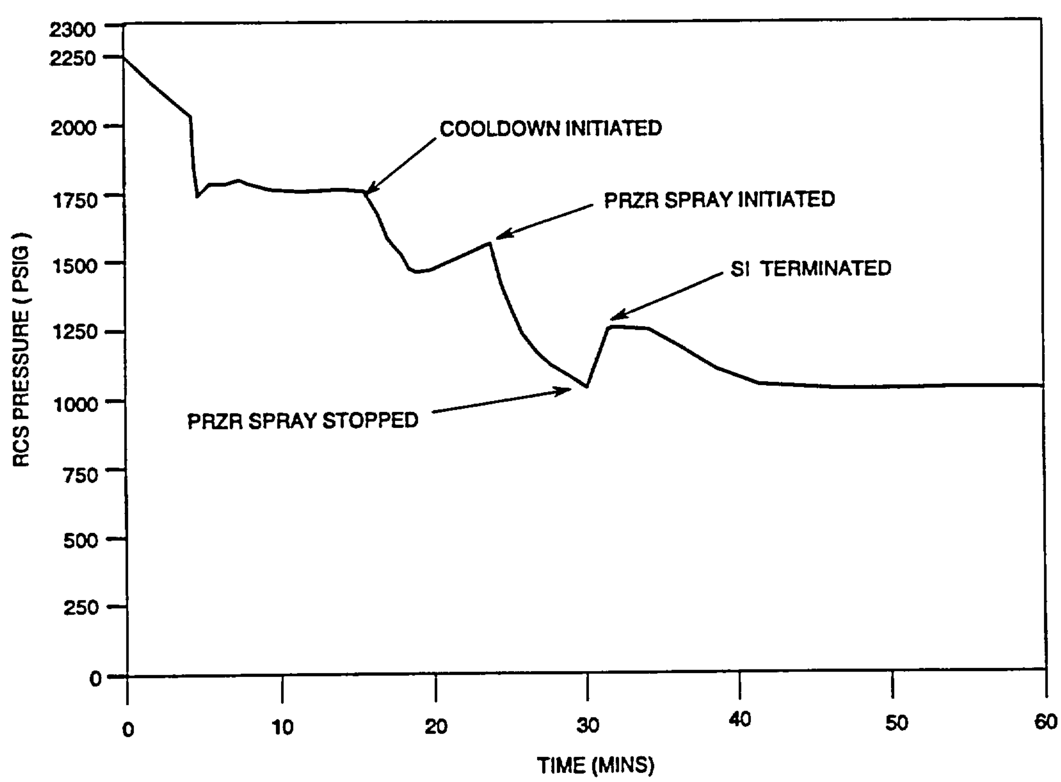


Figure 4.6-6 RCS Response - Offsite Power Available

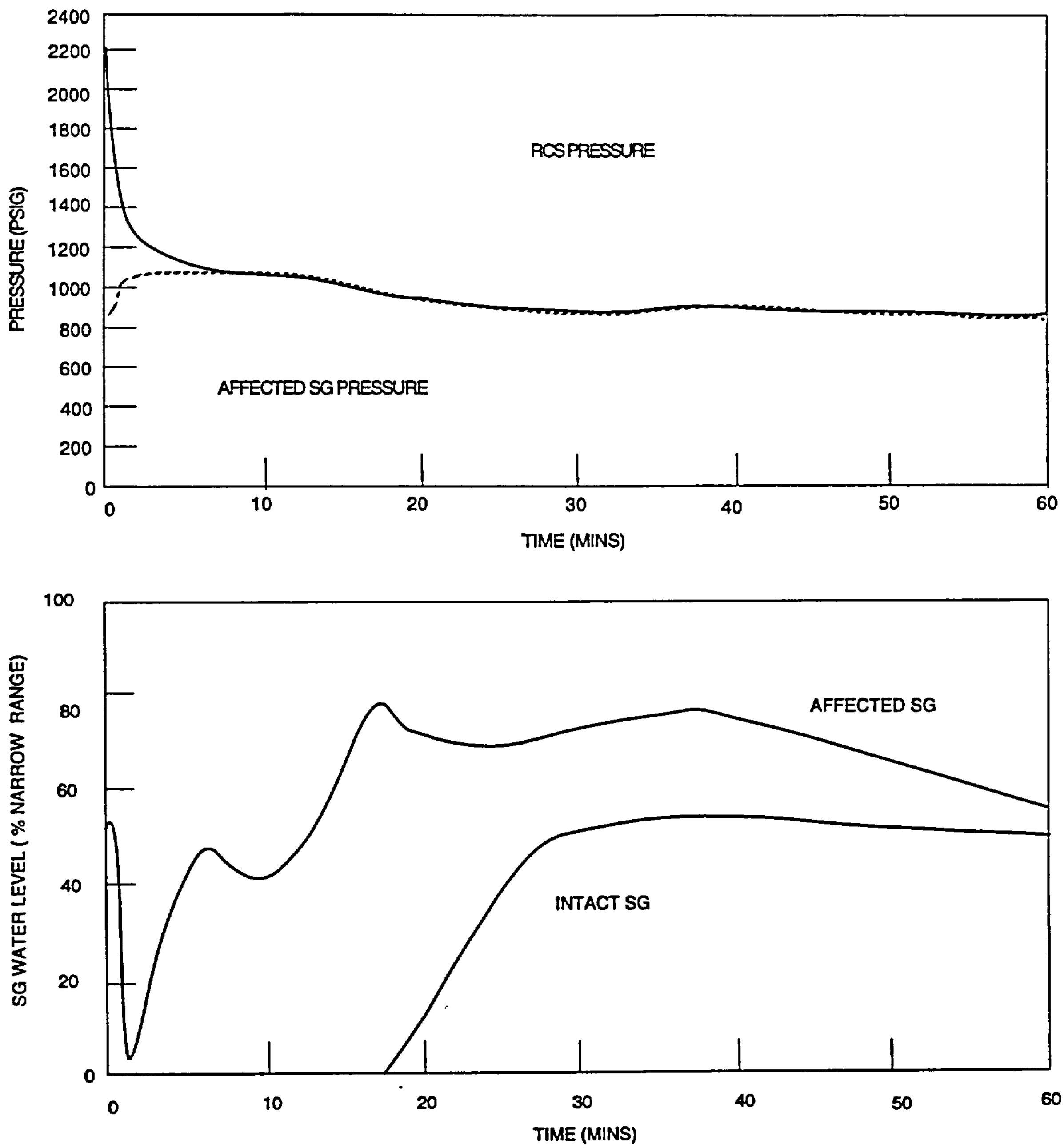


Figure 4.6-7 Multiple Tube Failure Response

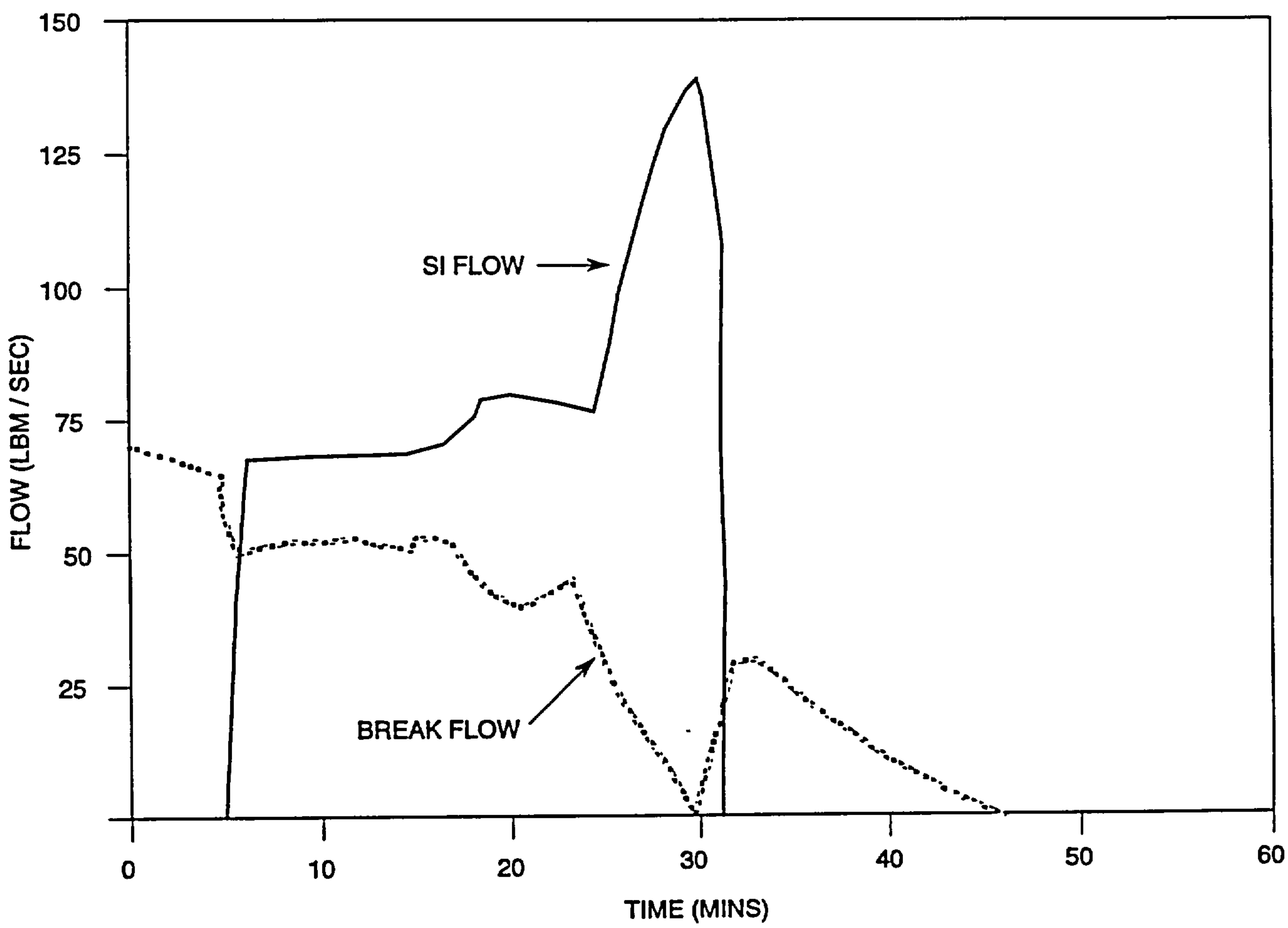


Figure 4.6-8 SI Flow and Break Flow

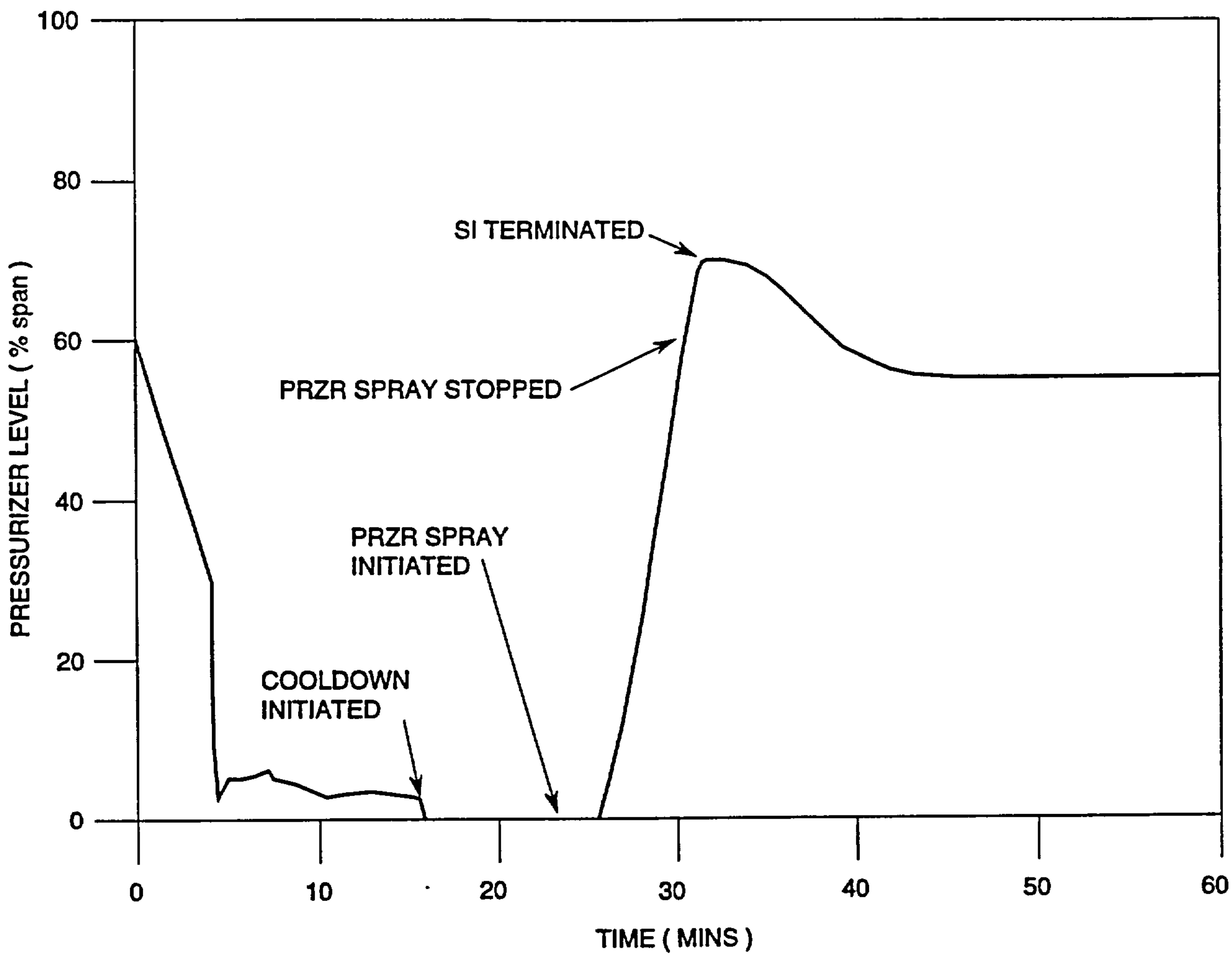


Figure 4.6-9 Pressurizer Level Response - Offsite Power Avaliable

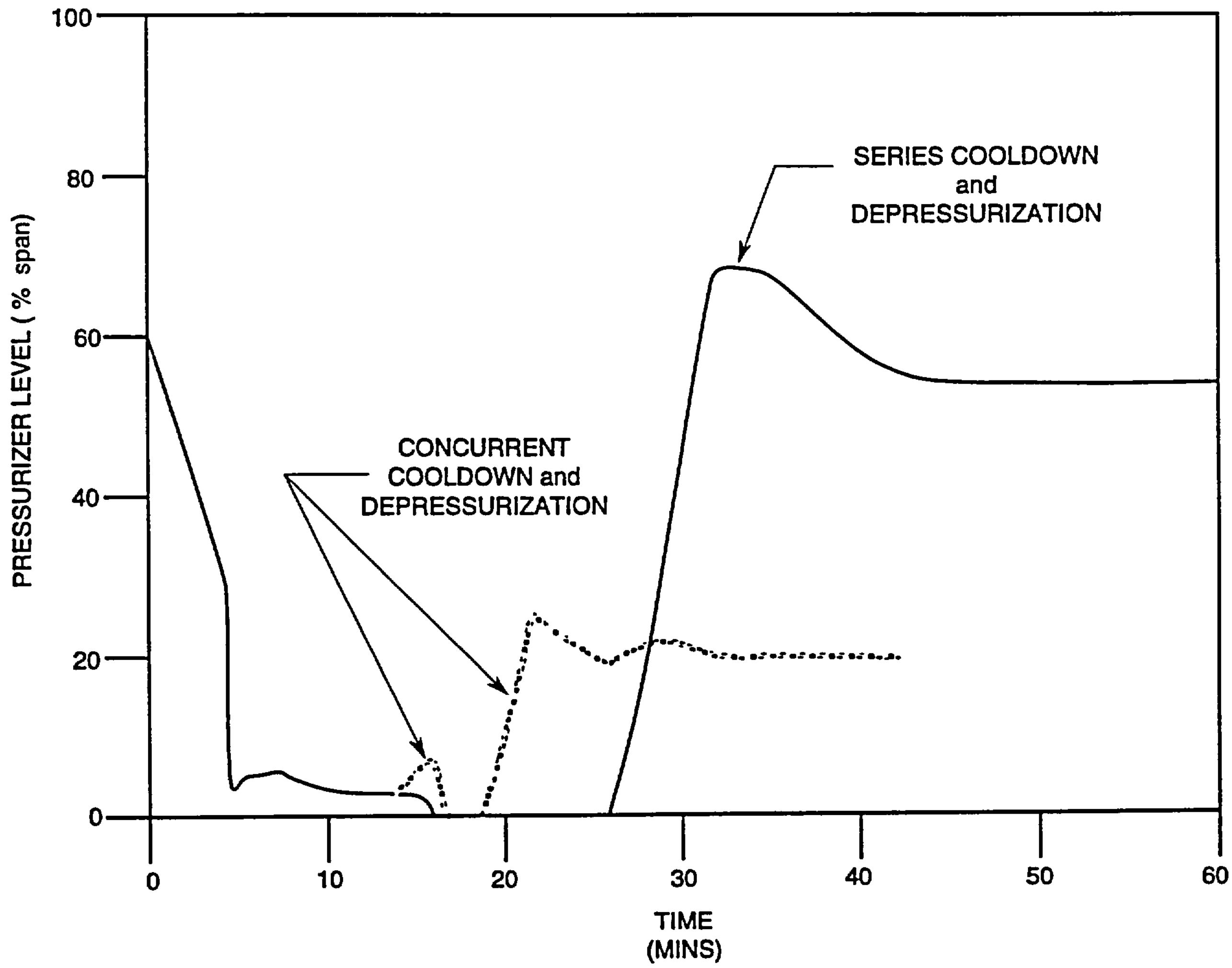


Figure 4.6-10 Pressurizer Level Response - RCS Cooldown and Depressurization

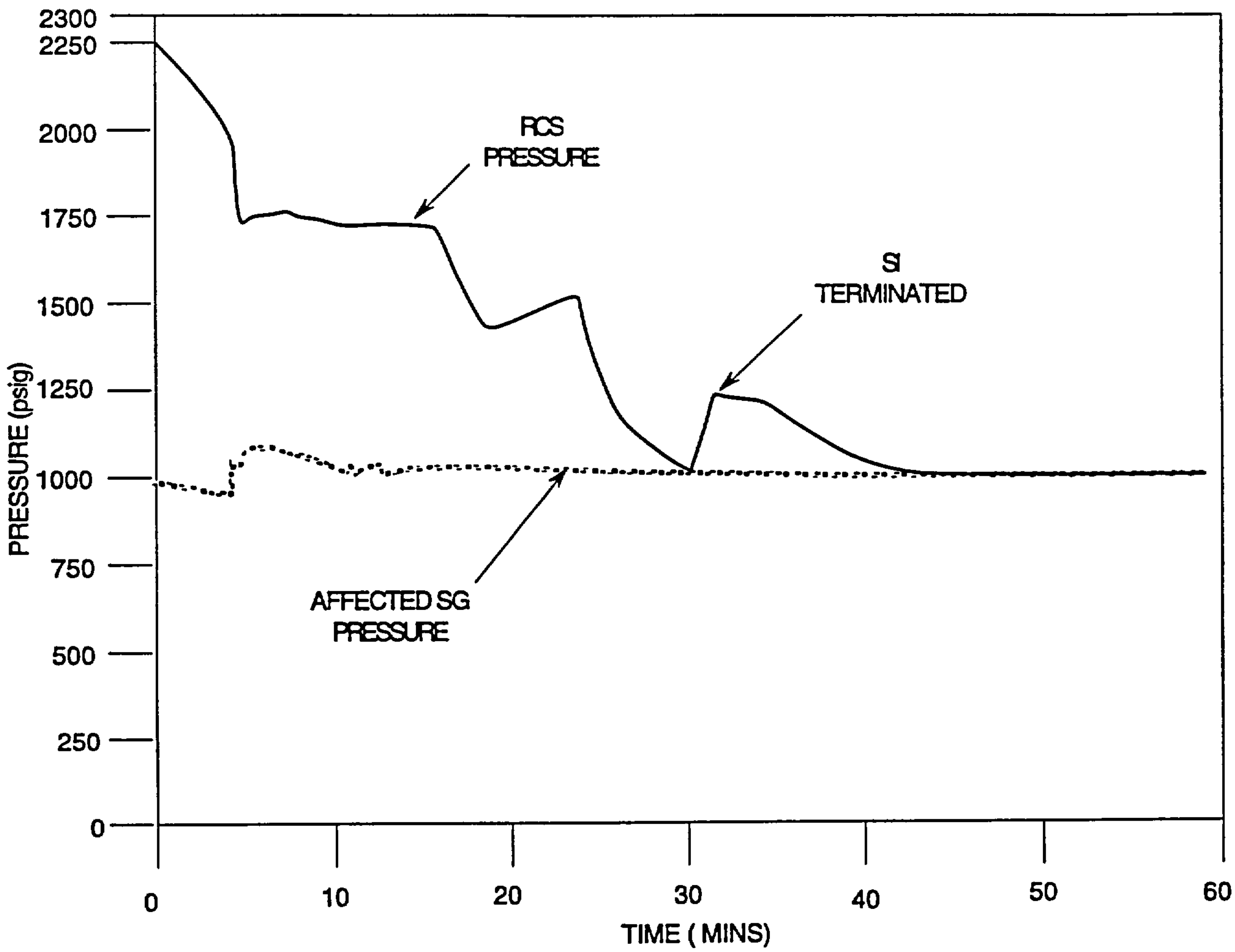


Figure 4.6-11 RCS and Ruptured SG Pressure Following SI Termination

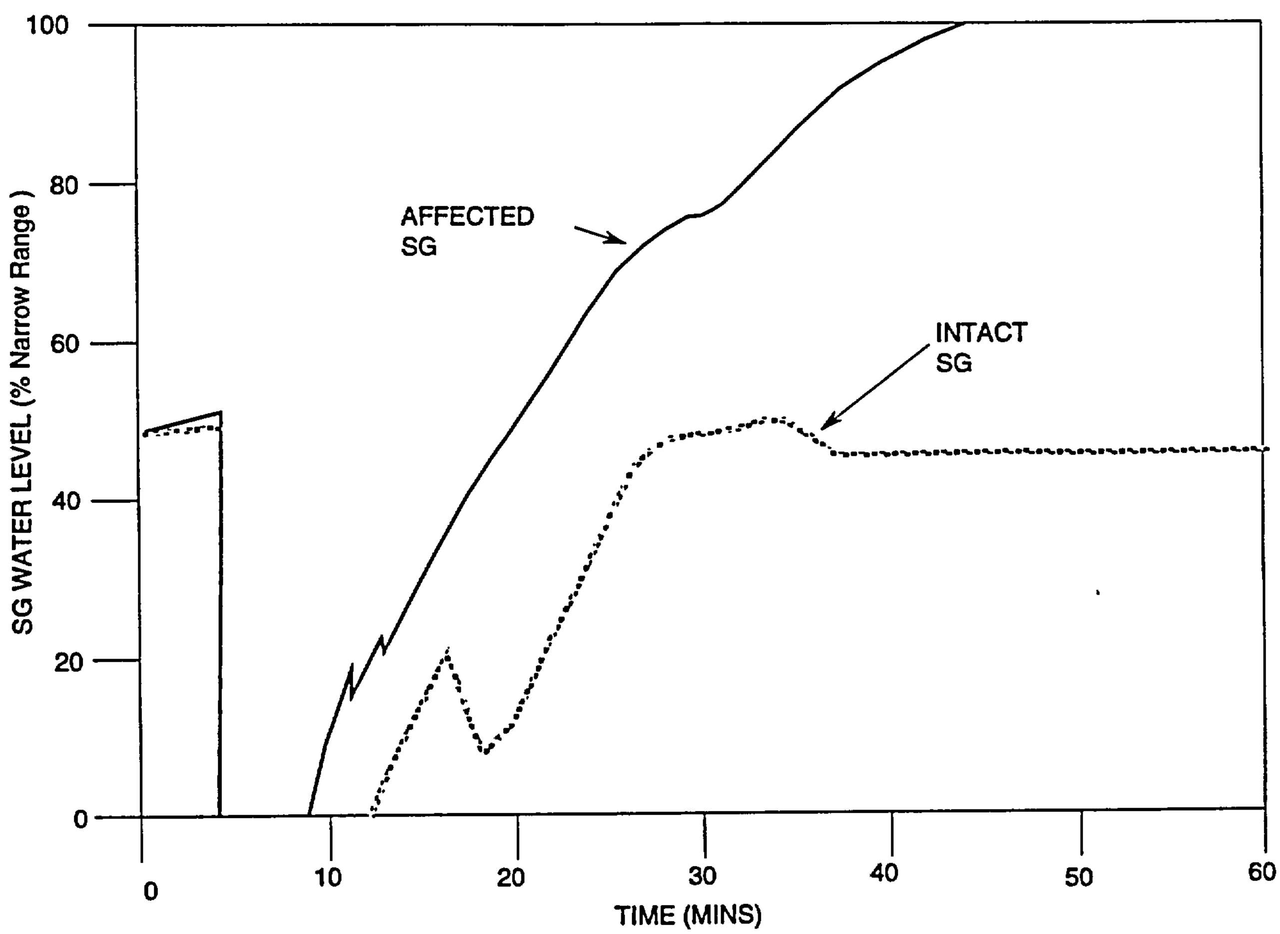


Figure 4.6-12 Steam Generator Levels

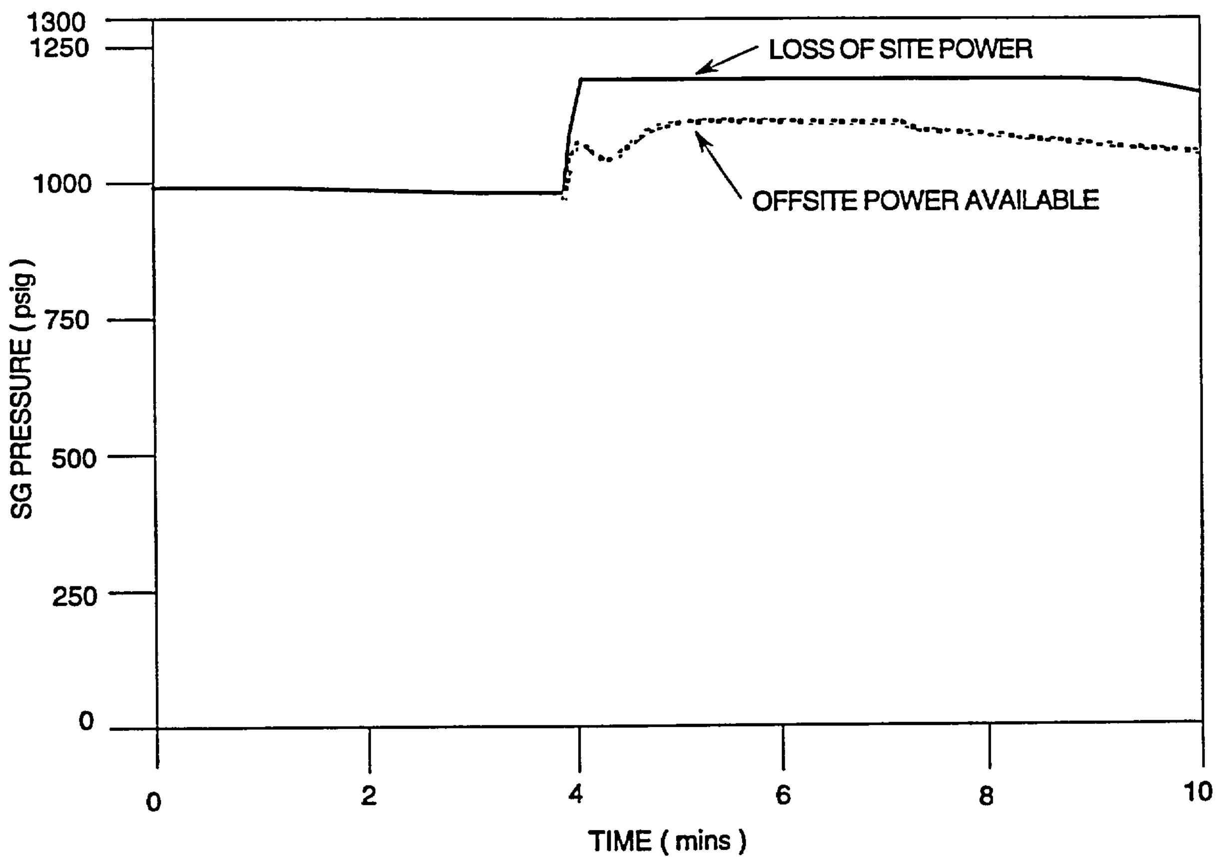


Figure 4.6-13 Steam Generator Pressure Following Reactor Trip With and Without Offsite Power

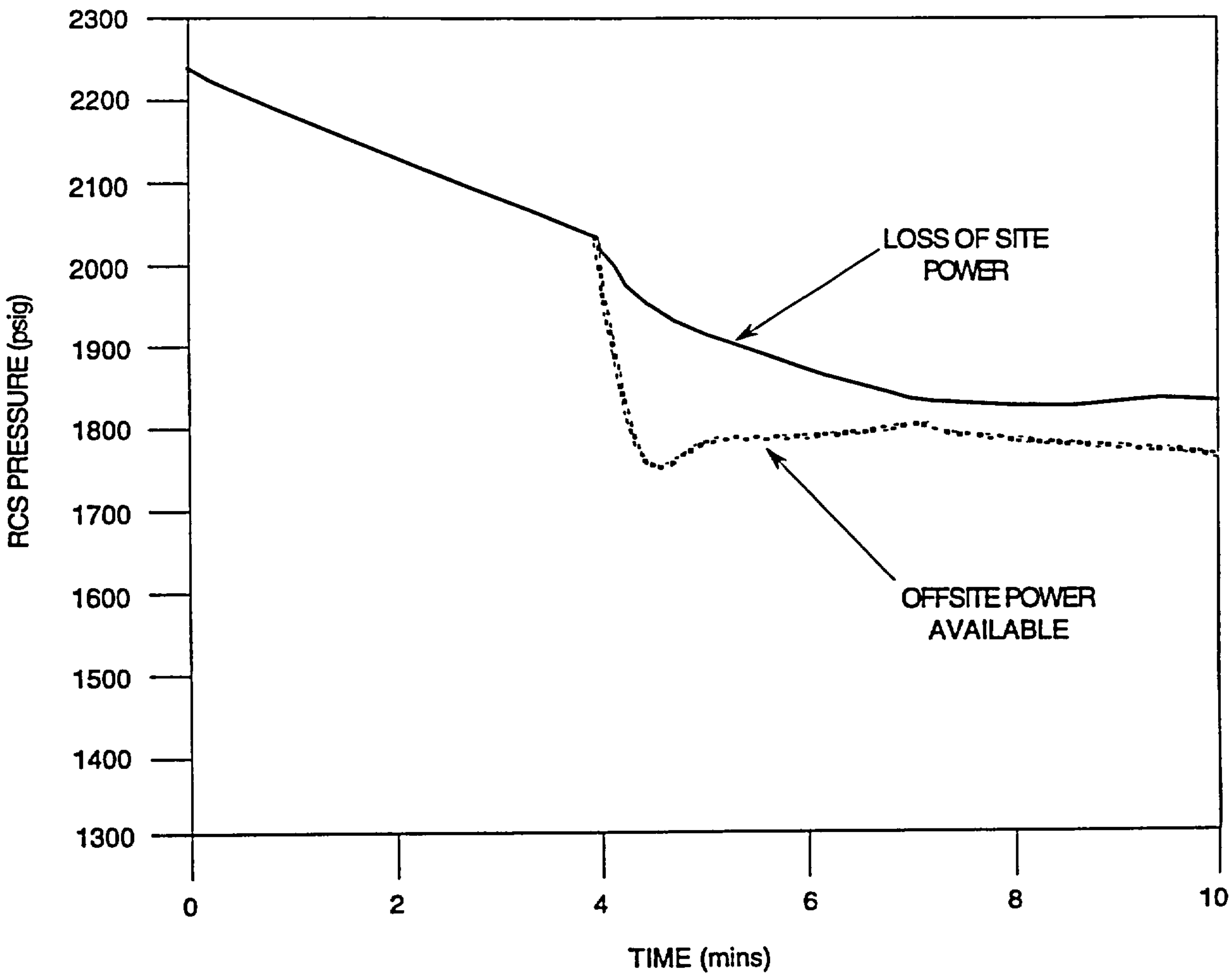


Figure 4.6-14 RCS Pressure Following Reactor Trip With and Without Offsite Power

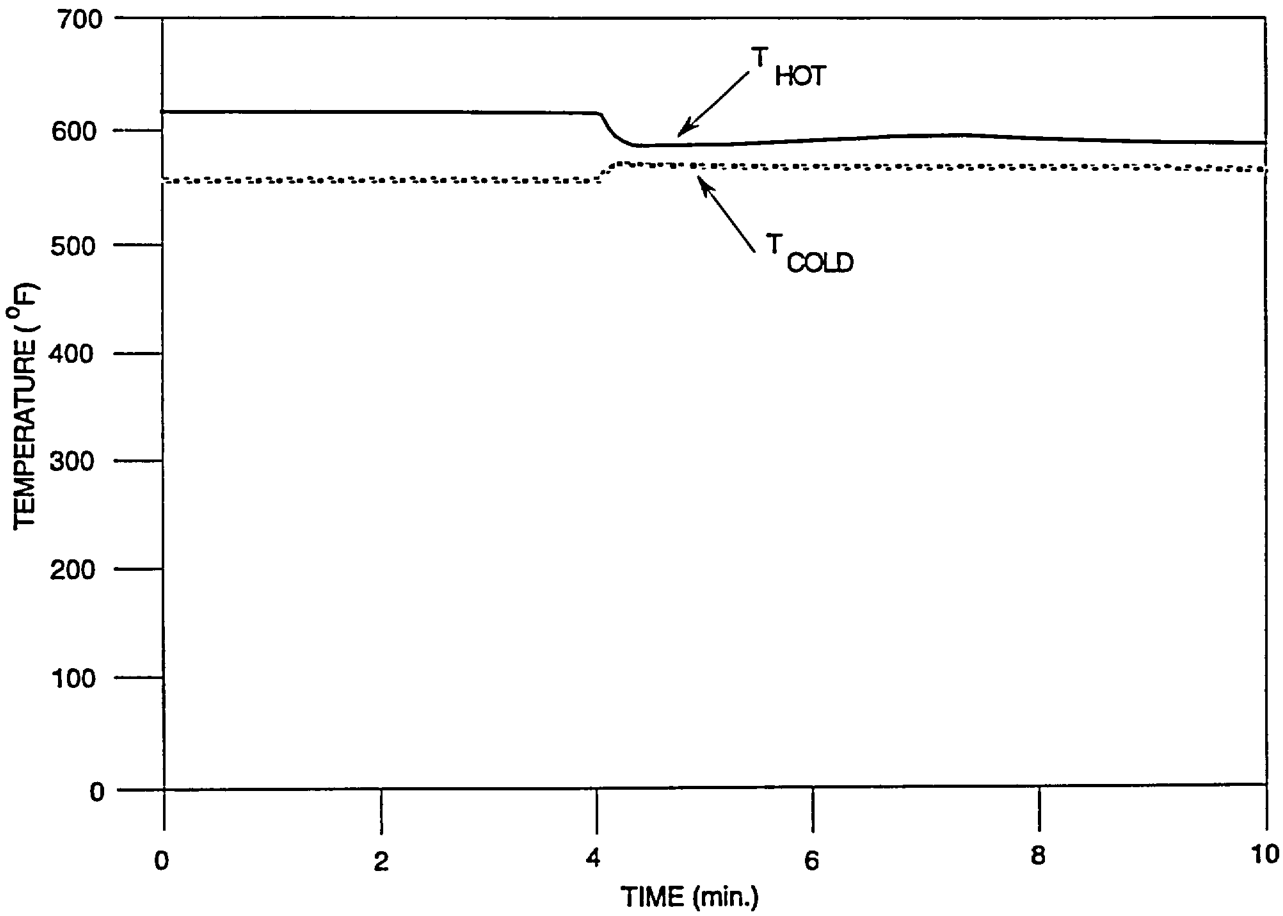


Figure 4.6-15 RCS Temperature Following Reactor Trip
Without Offsite Power

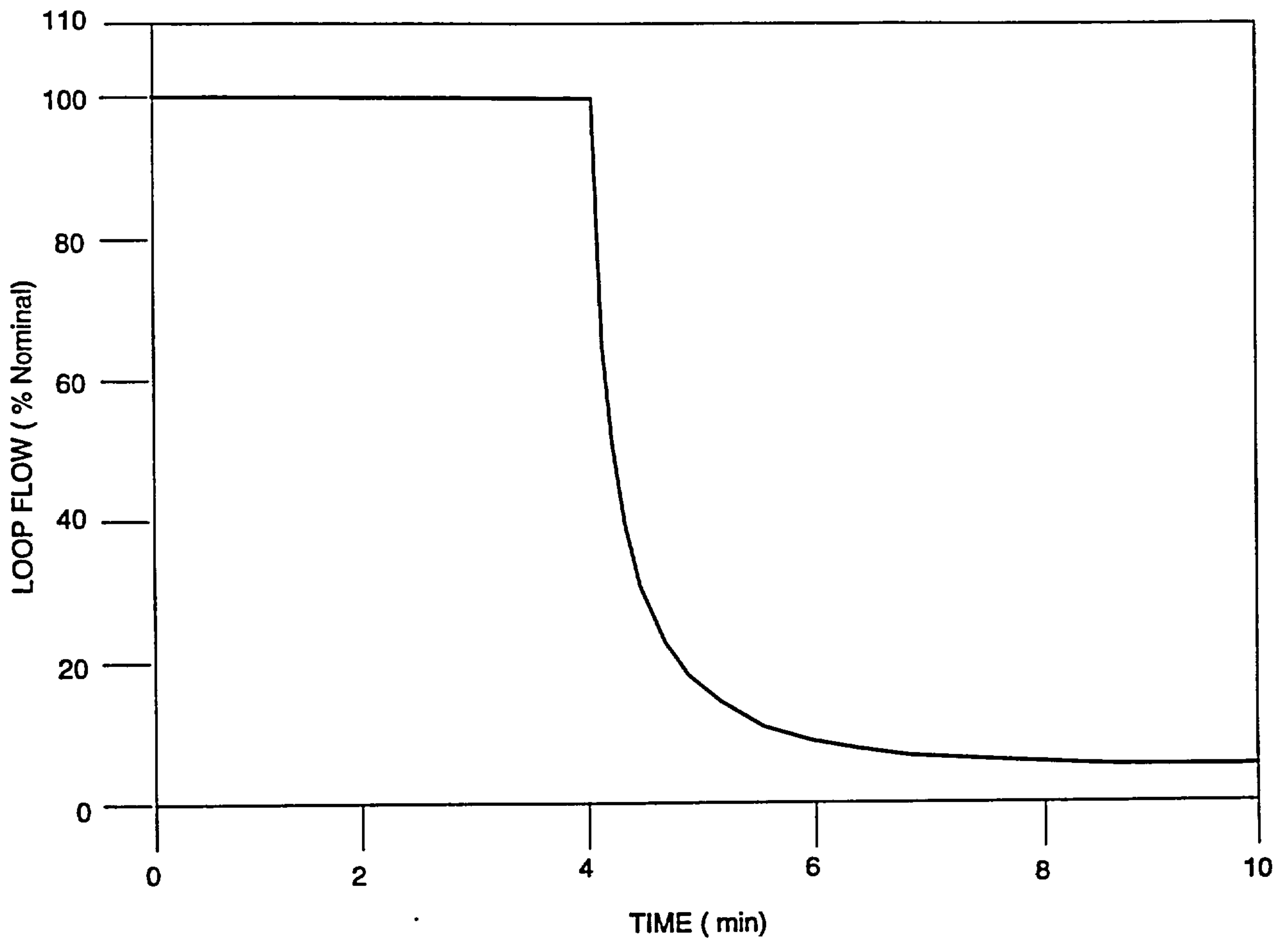


Figure 4.6-16 Natural Circulation Flow Following Loss of Offsite Power

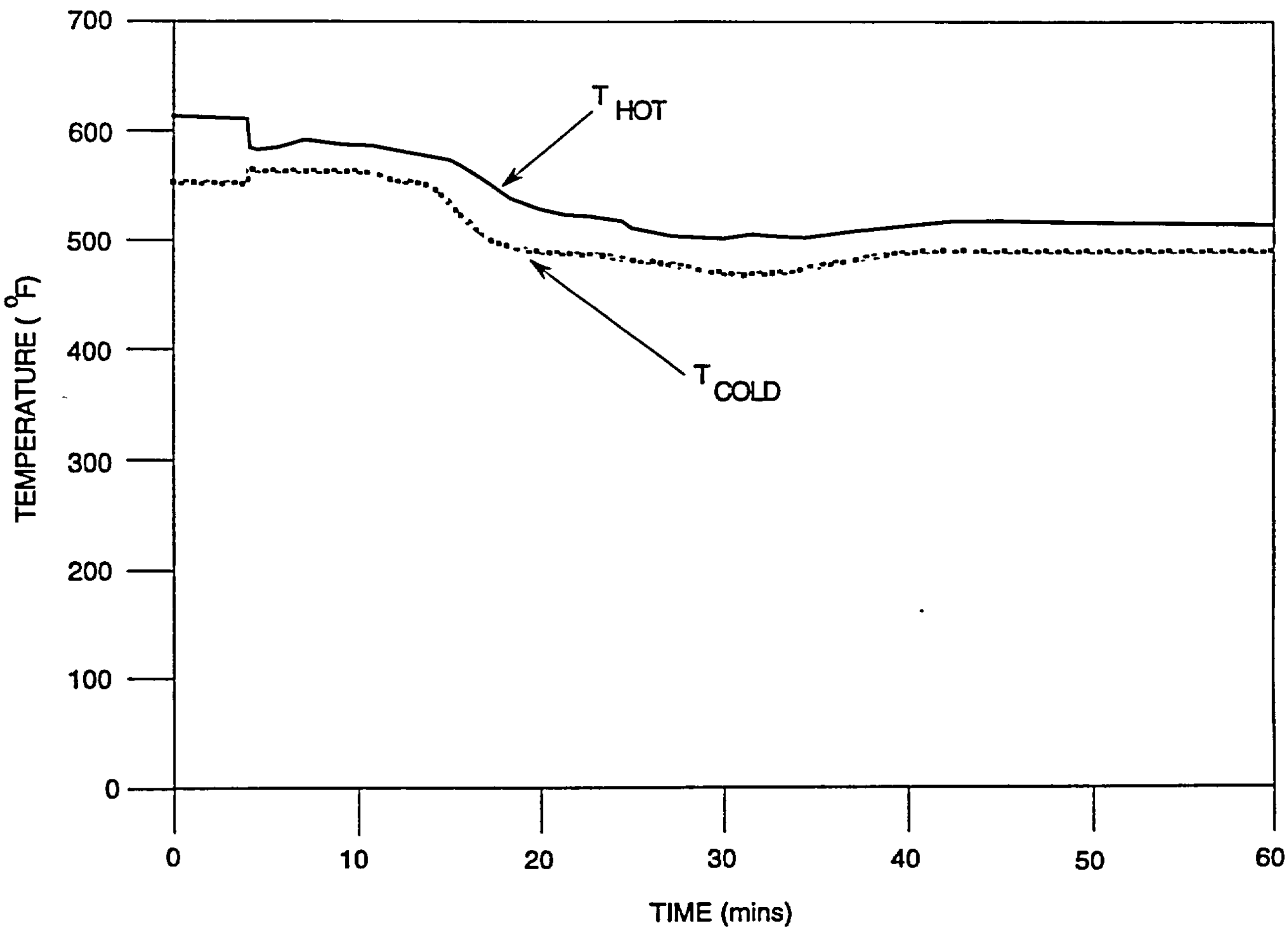


Figure 4.6-17 Intact RCS Temperature, Without Offsite Power

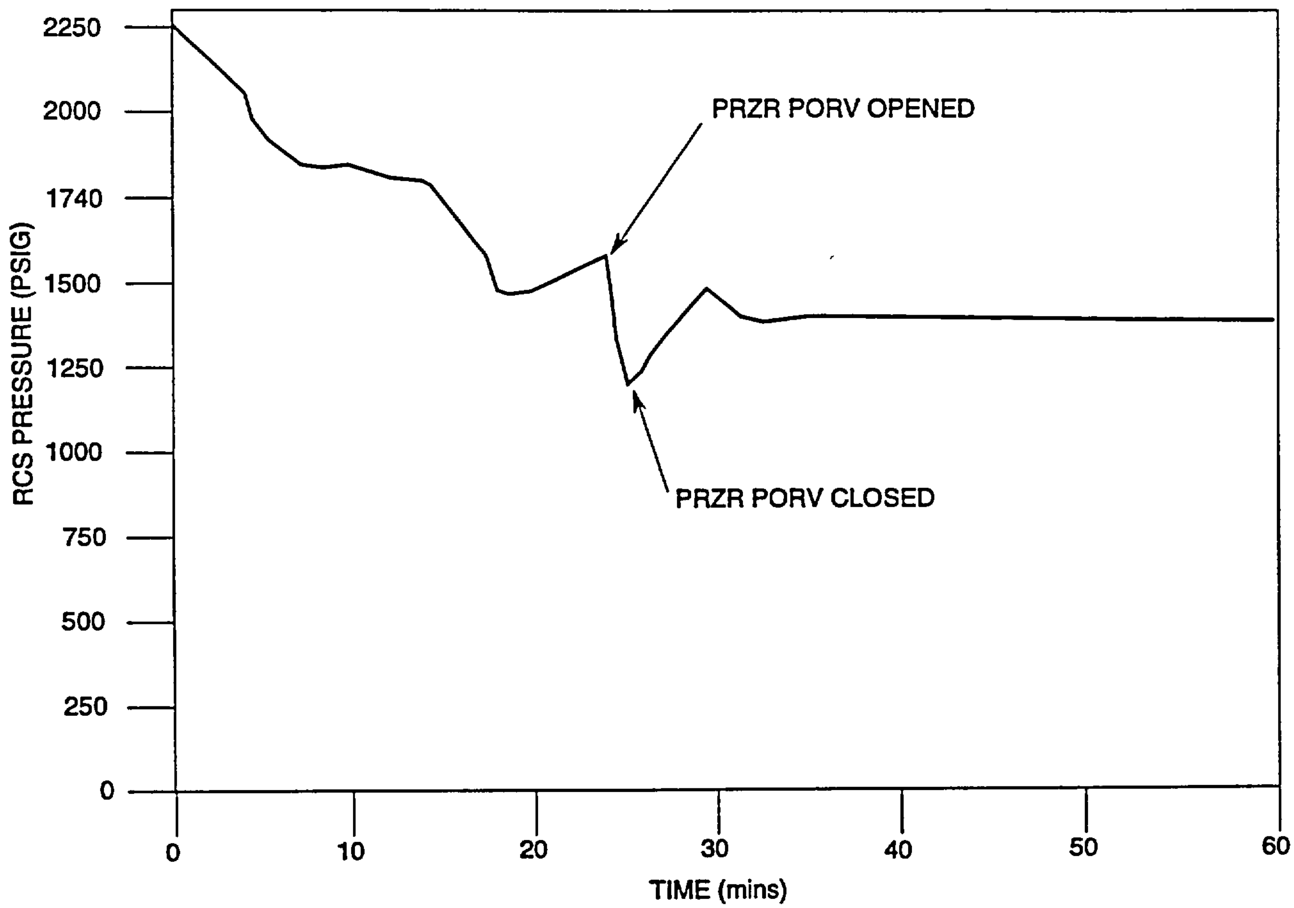


Figure 4.6-18 RCS Pressure Response, Without Offsite Power

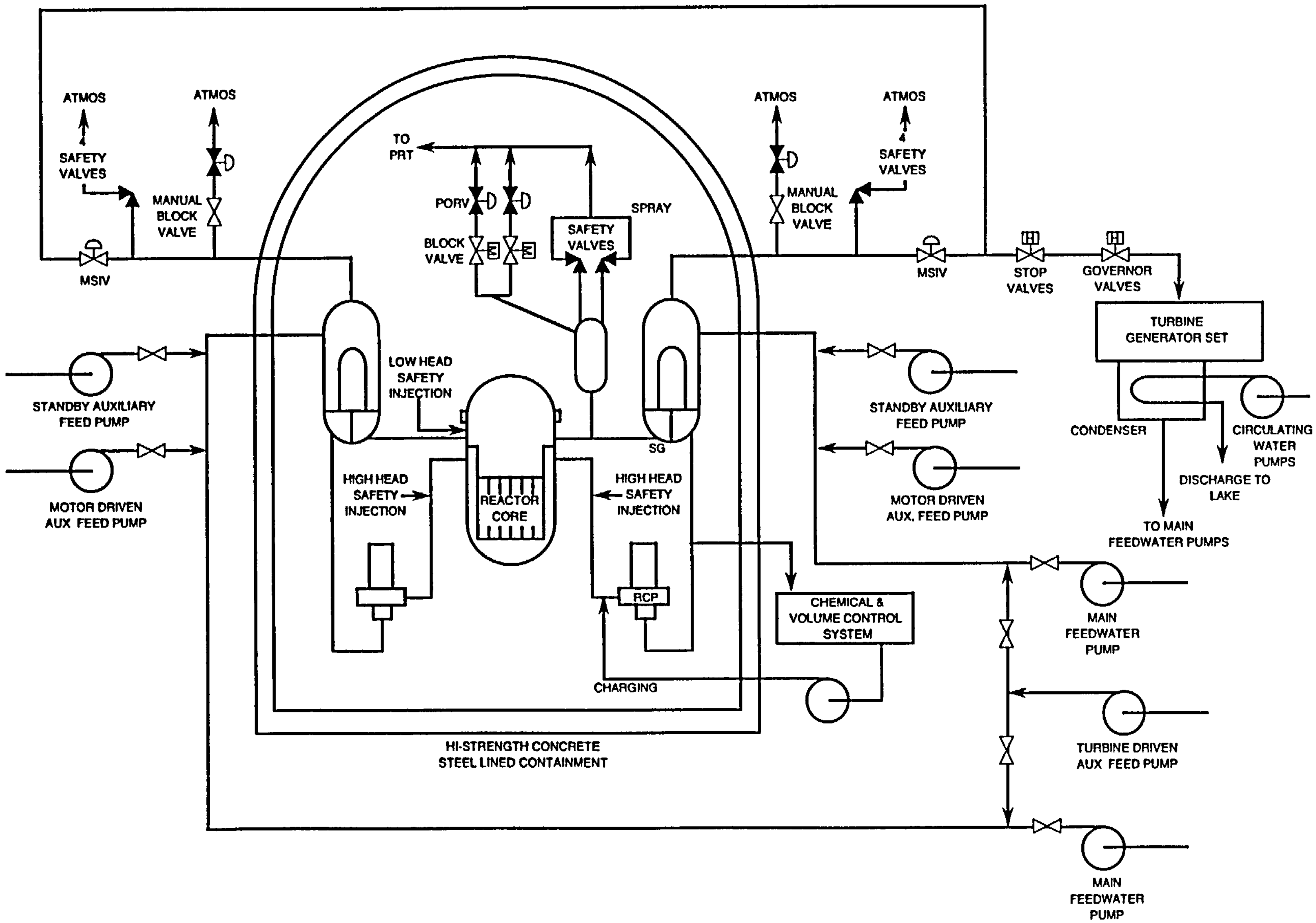


Figure 4.6-19 Schematic Diagram of Ginna NSSS

0191

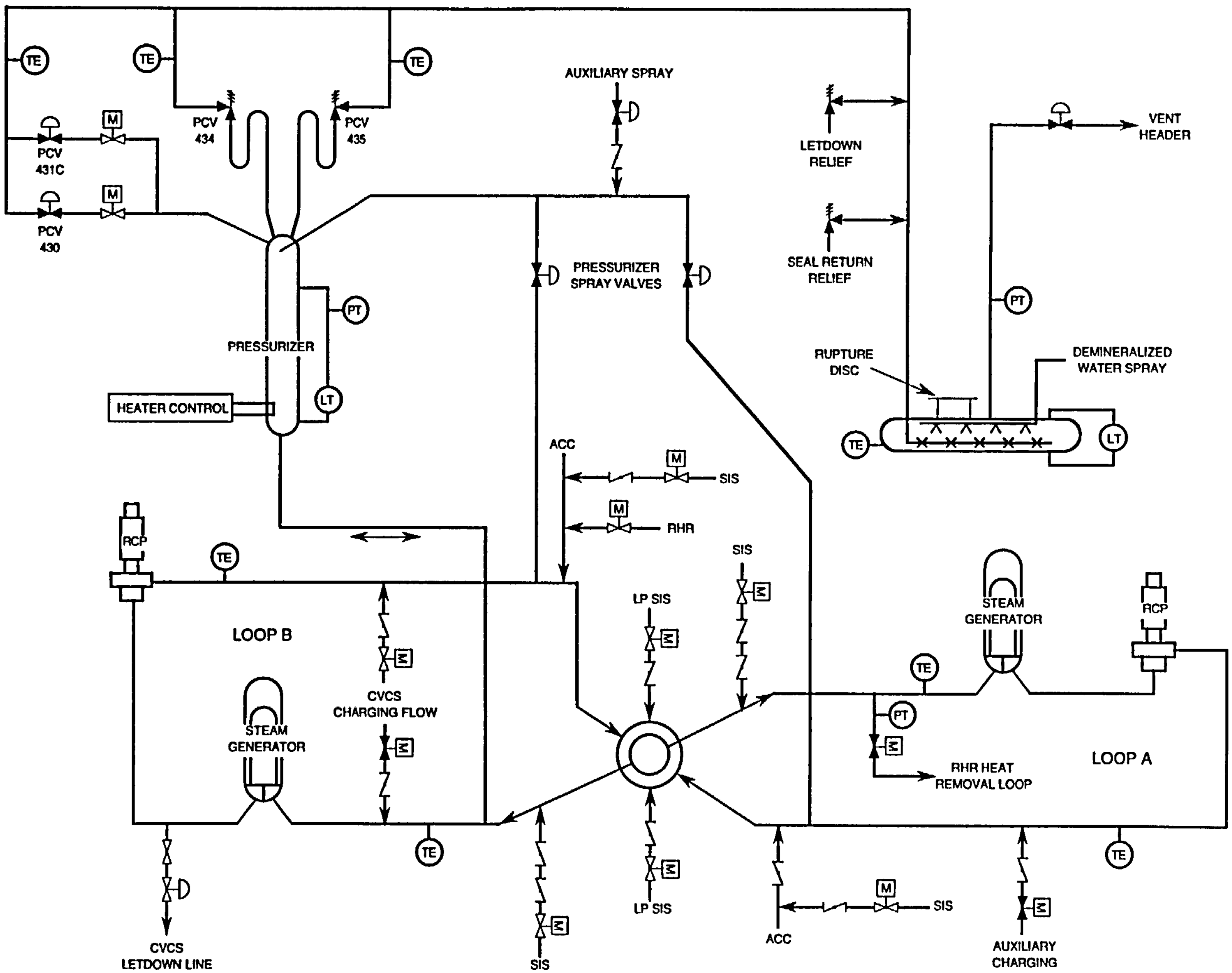


Figure 4.6-20 Ginna RCS Piping and Instrumentation Diagram

0191

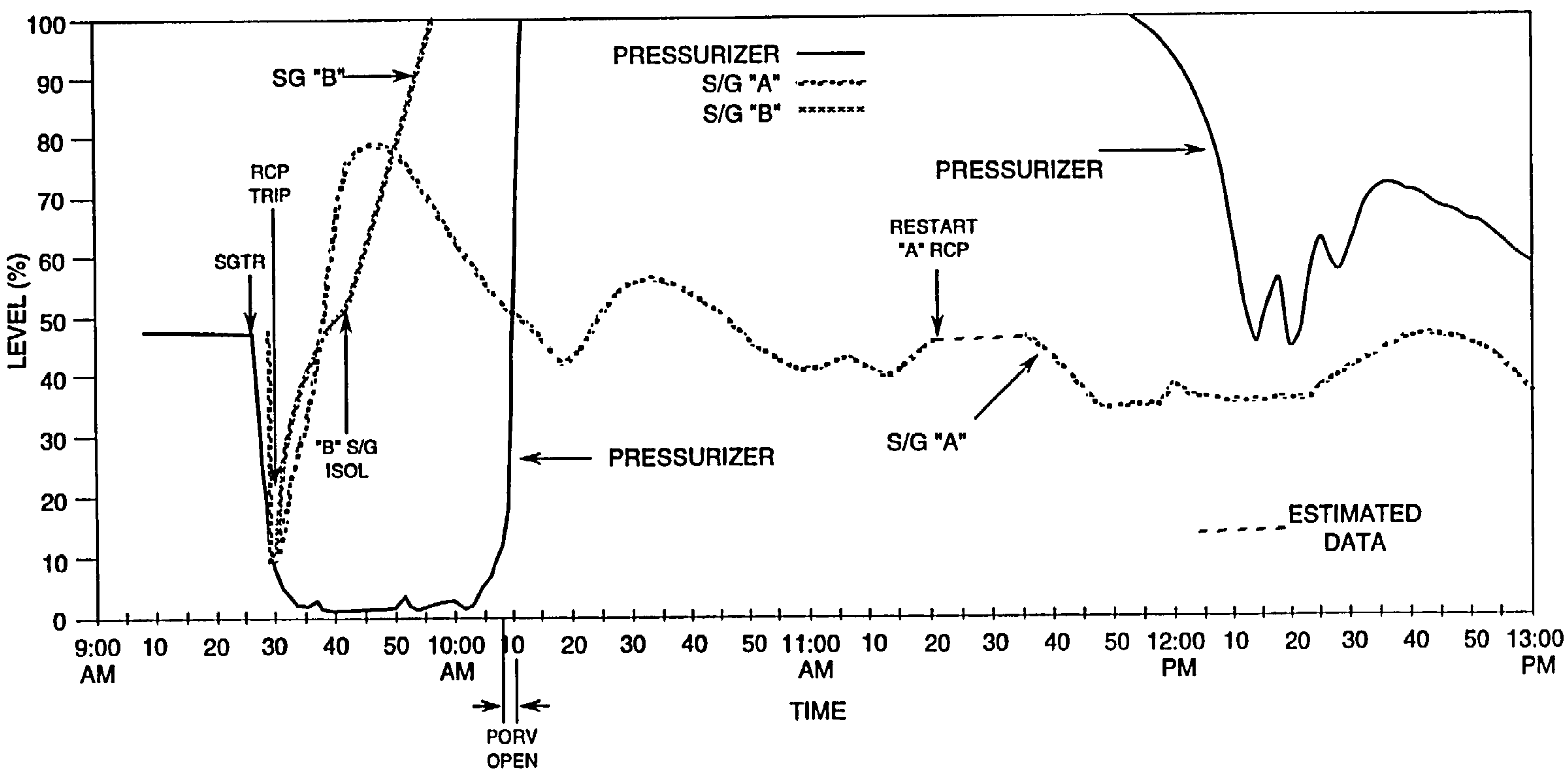


Figure 4.6-21 Ginna SGTR - Pressurizer and Steam Generator Level Response

0191

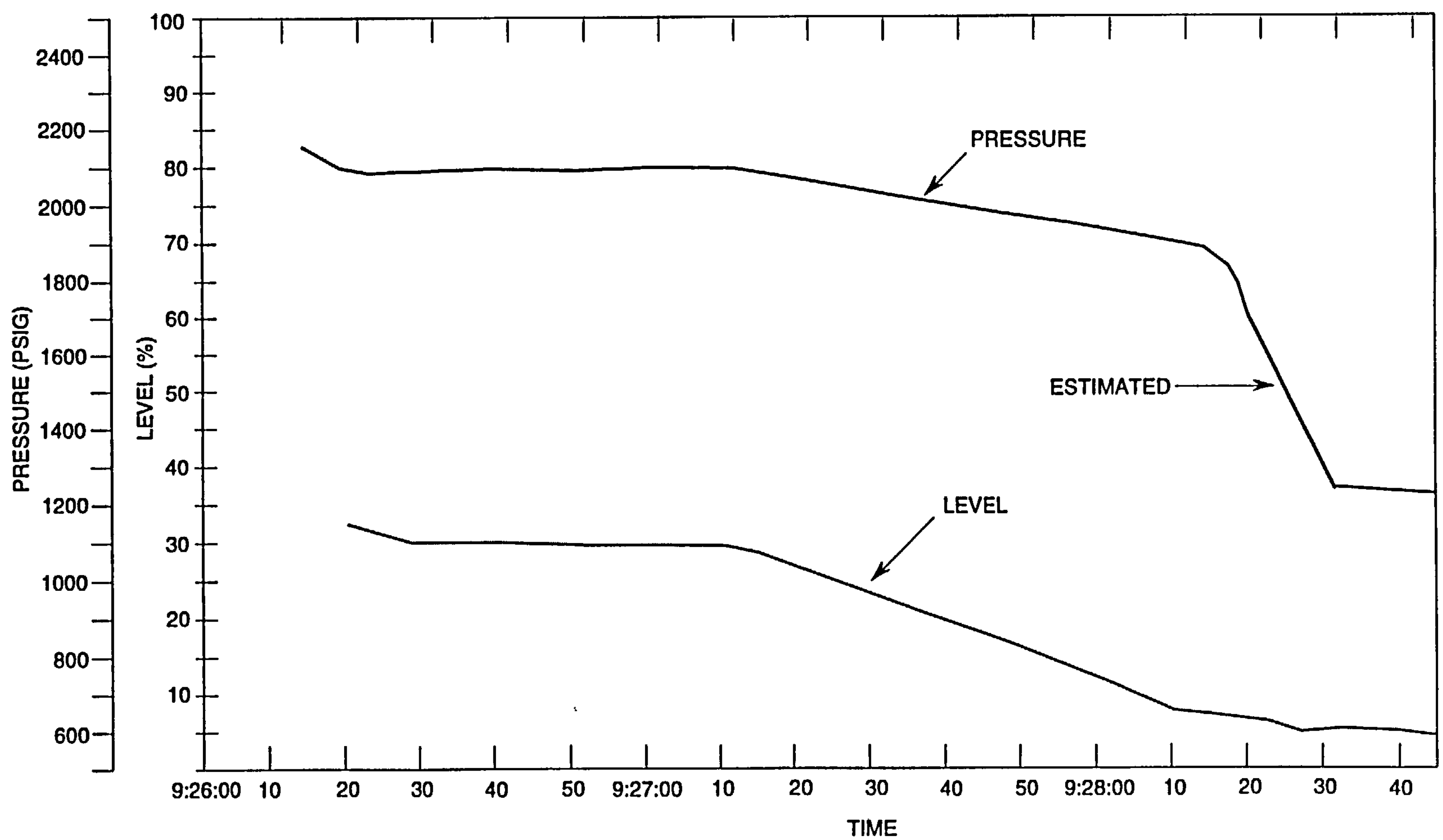


Figure 4.6-22 Ginna SGTR - Initial Pressurizer Pressure and Level Response

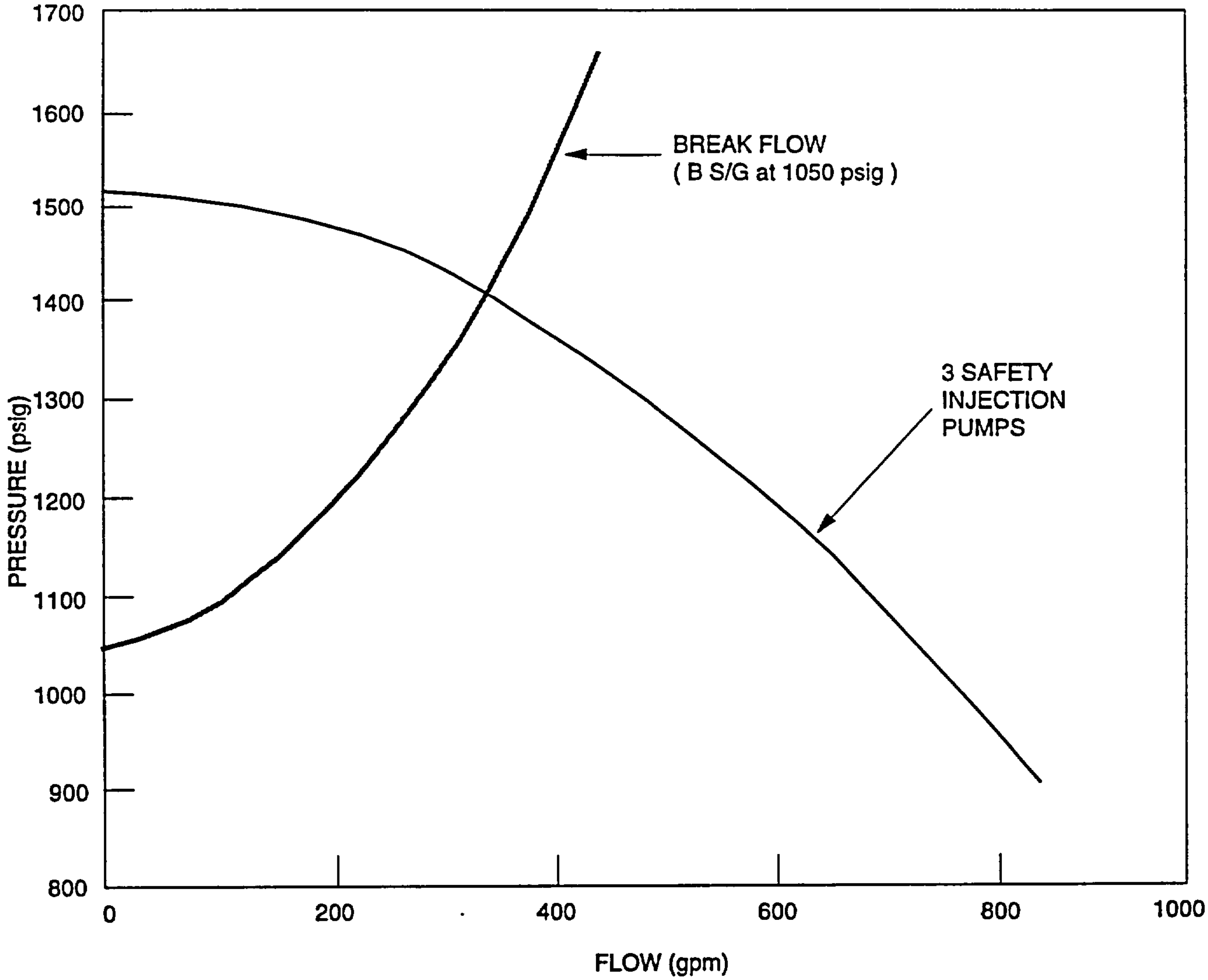


Figure 4.6-23 Ginna SGTR - SI and Break Flow

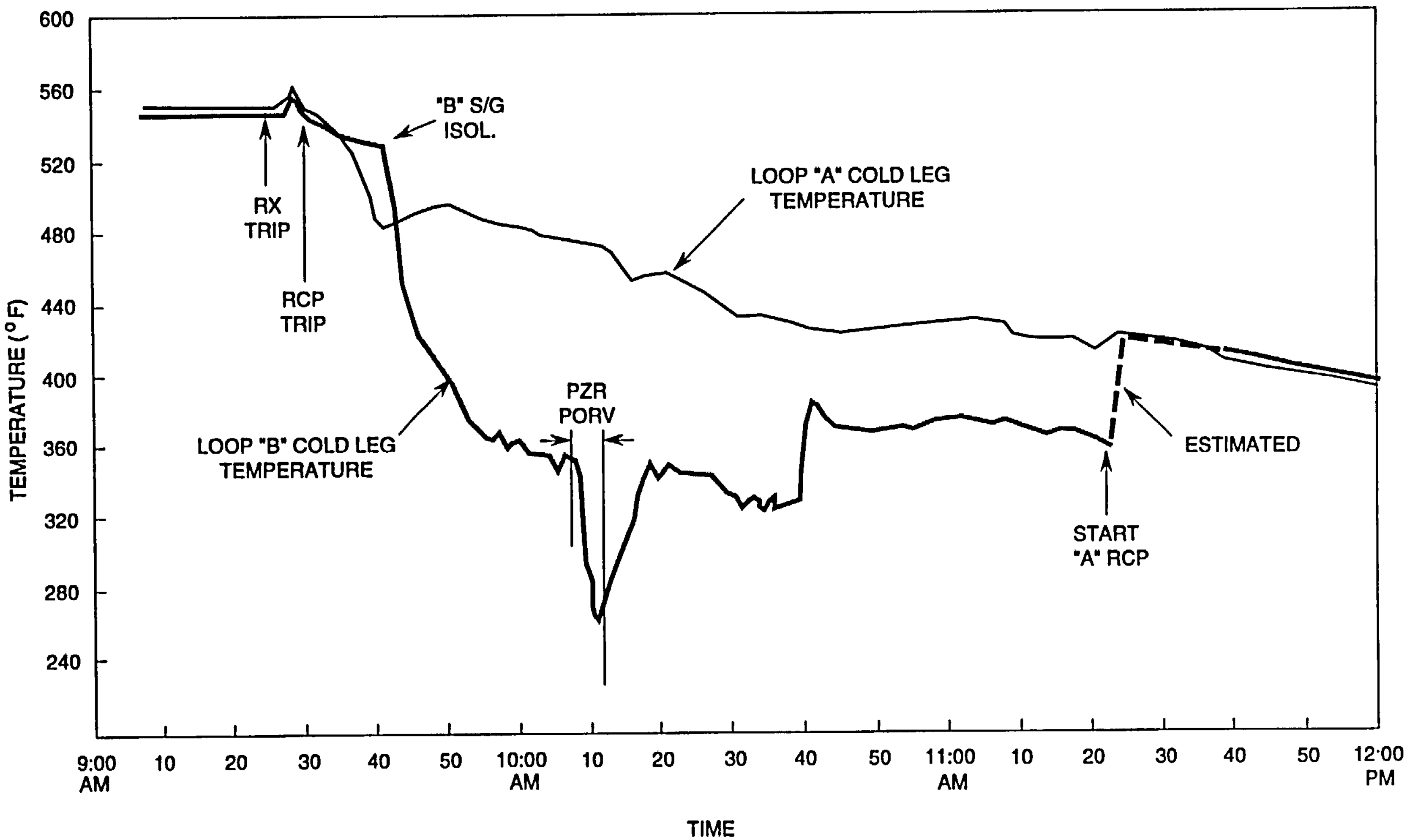


Figure 4.6-24 Ginna SGTR - Cold-Leg Temperature

0191

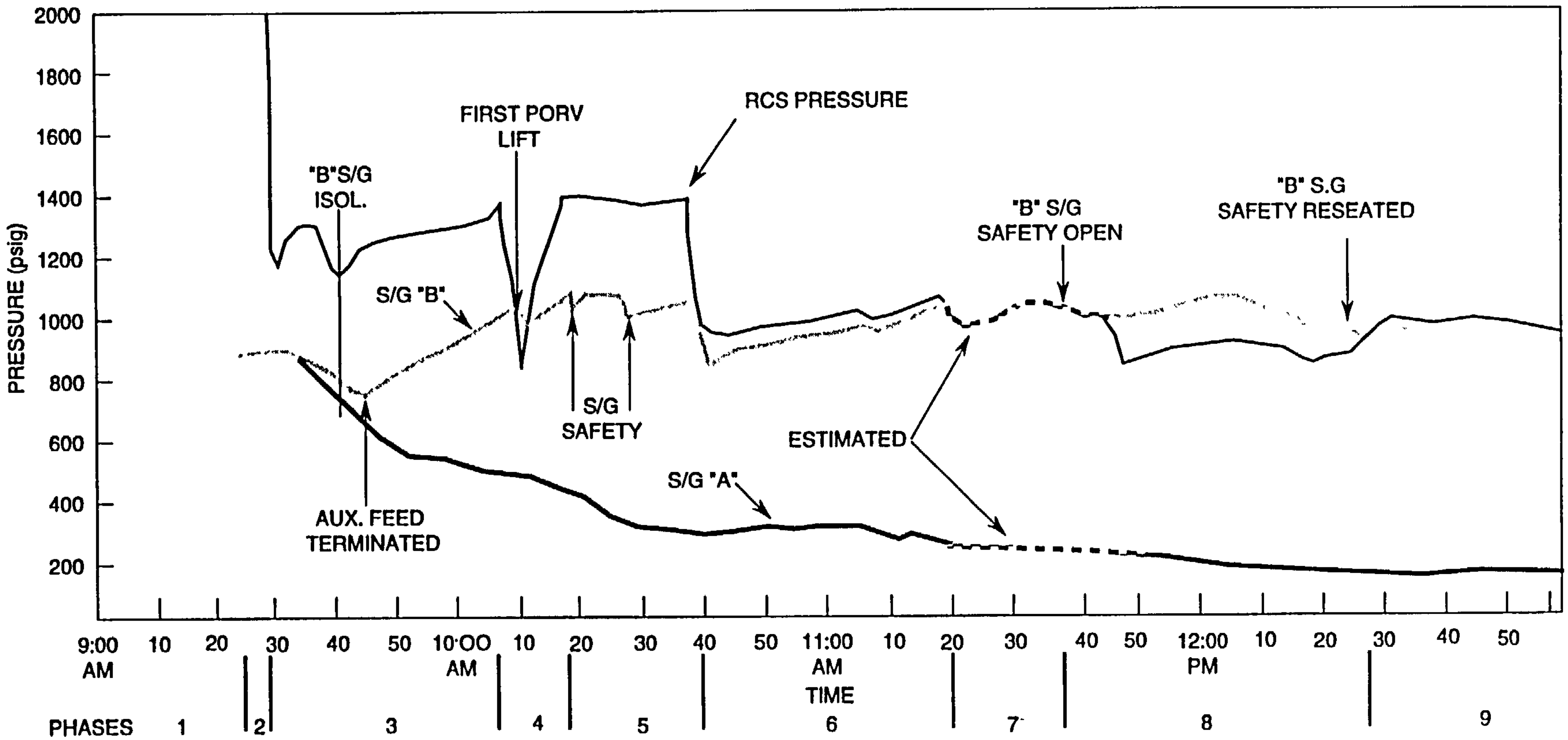


Figure 4.6-25 Ginna SGTR - RCS and SG Pressure

0191

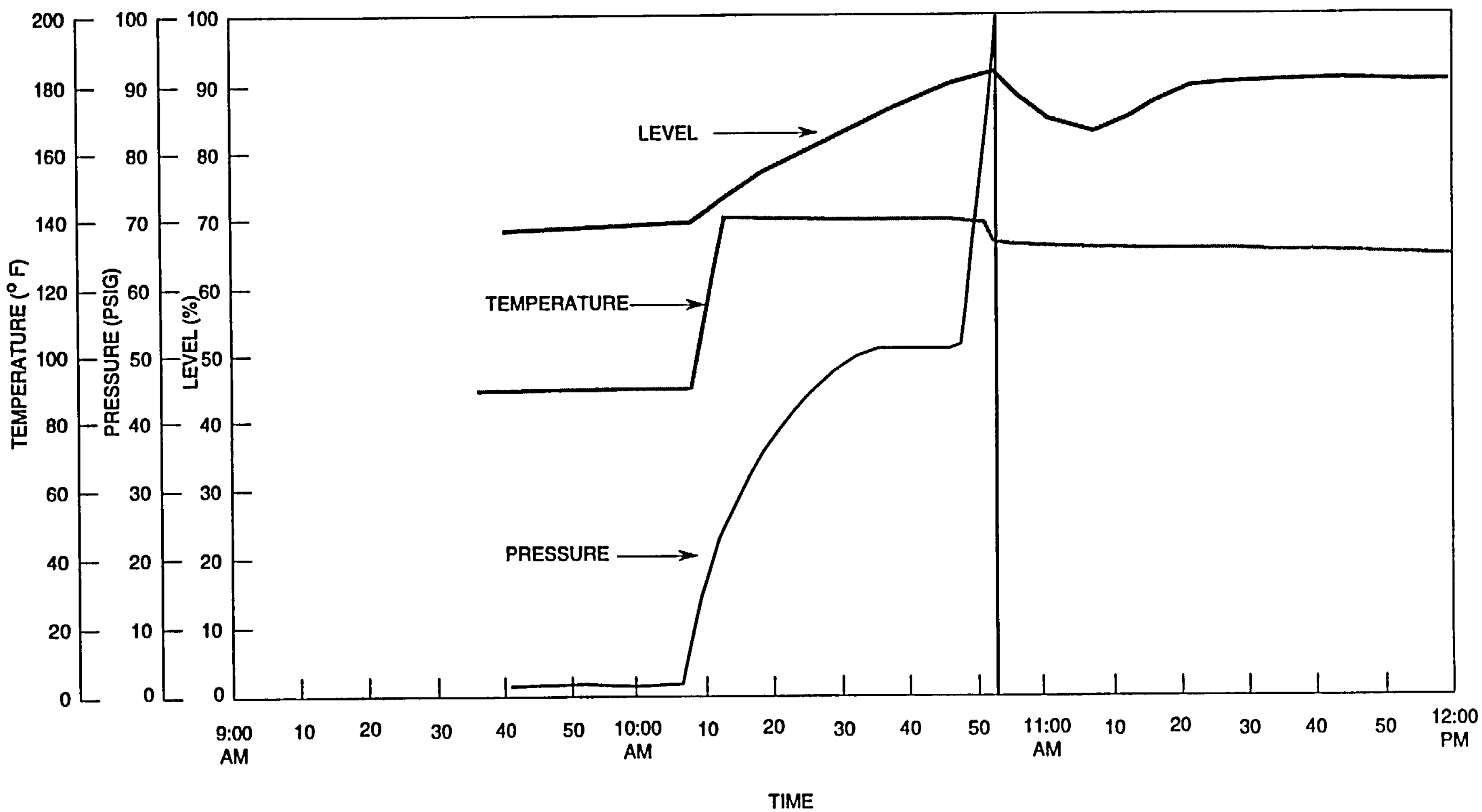


Figure 4.6-26 Ginna SGTR - PRT Parameters

0191

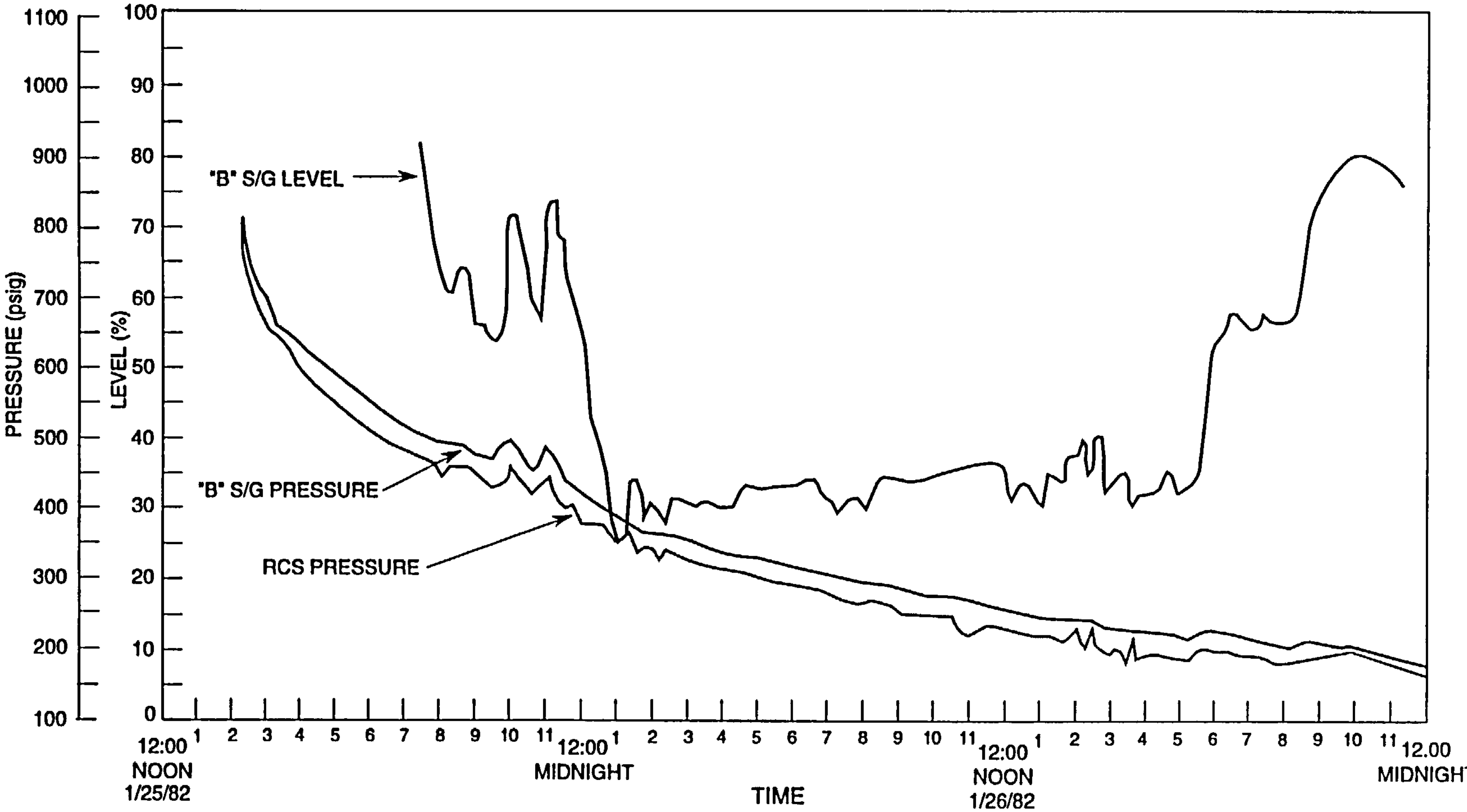


Figure 4.6-27 Ginna SGTR - Long-Term Cooldown and Depressurization

Westinghouse Technology Advanced Manual

Section 4.7

Anticipated Transient Without Scram (ATWS)

TABLE OF CONTENTS

LIST OF FIGURES

4.7 ANTICIPATED TRANSIENT WITHOUT SCRAM (ATWS)

Learning Objectives:

1. Define the term "anticipated transient without scram" (ATWS).

2. Describe the limiting (most severe) ATWS case for a pressurized water reactor (PWR).

3. List three parameters or components that affect a plant's sensitivity to an ATWS event.

4. Describe the modification made to Westinghouse reactor trip breakers after the Salem ATWS.

5. State the functions of the ATWS mitigation system.

6. List three event tree considerations (headings) used in estimating the conditional core damage probability of ATWS sequences.

4.7.1 Introduction

The definition for the term "anticipated transient without scram" can be found in 10CFR50.62, commonly known as the "ATWS rule." An ATWS is defined as an anticipated operational occurrence as defined in 10CFR50, Appendix A, followed by the failure of the reactor trip portion of the protection system specified in General Design Criterion 20 of Appendix A.

The term "transient" applies to any significant deviation from normal values of any of the key operating parameters. A transient may occur as a result of equipment failure or malfunction, or as the result of an operator error. Anticipated operational occurrences are further classified as Condition I and II events in ANSI 18.2. These events are expected to occur one or more times during the life of the plant.

Many transients are handled by various reactor control systems, which return the reactor to its normal operating condition. However, the more severe transients require that the reactor be shut down by the reactor protection system (RPS). As stated in the technical specification basis for reactor trip system instrumentation, the reactor trip avoids damage to the reactor fuel and cladding or to the reactor coolant system pressure boundary.

4.7.2 Reactor Protection System Design

The Westinghouse reactor protection system is shown in Figure 4.7-1. As shown, power to the control rod drive mechanisms (CRDMs) is supplied by motor generator sets through two series reactor trip circuit breakers. The opening of either reactor trip breaker de-energizes all CRDMs, and the reactor trips. This trip scheme is an example of one-out-of-two logic; it requires the actuation of only one protection train and the opening of only one reactor trip circuit breaker, at a minimum, to trip the reactor.

While this logic provides redundant means of generating a reactor trip, the testing of a reactor trip circuit breaker would result in a reactor trip without some compensating measure. Since testing is required, the RPS design includes bypass breakers that are manually installed during testing. For example, if a test of the A reactor trip breaker is required, a bypass breaker is racked in to provide a circuit path parallel to that of the A trip breaker to ensure continuity of power when the trip breaker is opened. The A bypass breaker is opened by the B protection train; therefore, during testing the reactor protection system is reduced to one-out-of-one logic.

The protection system consists of a number of analog channels. The analog section receives input signals from transmitters that sense process parameters. Each process signal is compared to a setpoint in a bistable. If the monitored parameter's input signal is equal to or exceeds the setpoint, a trip signal is generated by the bistable. The bistable trip signal is sent to redundant logic cabinets, where the reactor trip actuation signals are generated.

Each reactor trip function has a coincidence network; only one such network is shown in each protection cabinet of Figure 4.7-1. This coincidence is two-out-of-four logic. Assume that the instrument transmitters are supplying pressurizer pressure signals. If instrument transmitter 1 senses a high pressure condition (greater than the high pressure trip setpoint), its associated bistable trips. Both logic cabinets receive this signal and open the contacts associated with this channel. If no other contacts are open in this logic matrix, the undervoltage coils remain energized, and no trip occurs. If another transmitter also indicates a high pressure condition, its associated bistable trips, and now the necessary two-out-of-four logic is satisfied. When this occurs, vital power is interrupted to the undervoltage coils, allowing the reactor trip breakers to open.

4.7.3 ATWS Historical Background

The ATWS event became a possible source of concern for nuclear power plants in 1968 during discussions between the Advisory Committee on Reactor Safety (ACRS), the regulatory staff, and reactor instrument designers. There were various concerns, one of which was the possibility of interactions between control and protection functions in the instrumentation systems. After considerable discussion and some design changes, it was determined that separation of control and protection functions was being achieved to a reasonable degree, either by physical separation or electrical isolation.

The focus of interest with regard to instrumentation systems then shifted to the ability of the shutdown systems to function with the needed reliability considering common-mode failures. Common-mode failures are failures due to design deficiencies or maintenance errors that could render inoperable redundant components or portions of a safety system. At the time, it was difficult to determine whether a common-mode failure was adequately accounted for partially because the techniques to analyze such failures were not fully developed.

In 1969, the efforts to evaluate the safety concerns of the ATWS events were divided into two areas. One area was concerned with attempting to evaluate the likelihood of common-mode failures or any other failure of the reactor protection system. The second area was to analyze the consequences of various postulated ATWS events.

The ATWS event was analyzed in combination with different initiating conditions. The results showed that the worst-case ATWS initiating event for a pressurized water reactor is a loss of main feedwater.

A loss of main feedwater normally results in a reactor trip to prevent a loss of heat sink. The signal input to the reactor protection system to indicate that a loss of heat sink has occurred is a low-low level in one or more of the steam generators. However, the ATWS analysis assumes that a common-mode failure occurs which prevents the proper operation of the reactor protection system, and the reactor does not automatically trip.

With the loss of heat removal by the steam generators and the lack of a reactor trip, energy from the reactor causes a rapid increase in the reactor coolant temperature. The resultant coolant expansion causes an insurge into the pressurizer, which compresses the pressurizer steam volume. The compression of the pressurizer steam space causes the pressure in the reactor coolant system to rapidly increase. Since systems such as the rod control and pressurizer pressure control systems are not safety-grade, no credit is taken for their action. Therefore, as the temperature continues to increase, the pressure in the reactor coolant system also continues to increase.

As the primary temperature increases, the steam generator pressure increases. The increased secondary pressure causes the steam line code safety valves to open. Even though the auxiliary feedwater system is discharging to the steam generators, the feed rate is insufficient to match the rate of mass loss through the safety valves. The result of the steam generators drying out is that the reactor coolant system temperature increases at a faster rate.

For a reactor with a negative moderator temperature coefficient (MTC), the increasing reactor coolant system temperature adds negative reactivity, which decreases reactor power. Unfortunately, the decrease in reactor power and resultant tempering of the coolant temperature increase are not enough to prevent the pressurizer from filling. When the pressurizer is completely filled, or becomes water solid, an increasing reactor coolant temperature results in a very high reactor coolant system pressure. For all PWR analyses, pressures in excess of 3000 psia are reached. Since this pressure is in excess of the design pressure (2500 psia) of the reactor coolant system, there is a concern about possible system damage and degradation of the emergency core cooling system interfaces.

The severity of an ATWS (peak pressure reached) initiated by a loss of feedwater is affected by the following parameters:

1. The value of the moderator temperature coefficient,
2. The size of the pressurizer,
3. The size of the pressurizer safety valves,
4. The secondary inventory, and
5. The main turbine status (operating or tripped) during the transient.

The value of the moderator temperature coefficient determines whether and how much negative reactivity is added (and the resultant reactor power decrease) as the reactor coolant temperature increases. Therefore, the worst case for the transient is at the beginning of core life (especially for high burnup cores), when the moderator temperature coefficient can be positive, or negative with a small magnitude.

The pressurizer volume is important from the standpoint of the time required to reach the solid-water condition. The size of the code safety valves determines the amount of coolant outflow when the system becomes solid. If the capacity of the code safety valves is small, then the ultimate pressure reached in the reactor coolant system will be higher.

The amount of mass in the secondary side of the steam generators determines the dry-out time of the steam generators. As previously discussed, after the steam generators dry out, the heat sink for the reactor coolant system is lost, and reactor coolant system pressure rapidly increases.

The severity of the accident is also affected by whether the main turbine is operating. It would appear that the loss of feedwater transient would be less severe if the main turbine remains in service, so that additional heat is removed from the reactor coolant system. However, this heat removal path results in a loss of steam generator inventory and decreases the time required to dry out the steam generators. A shorter dry-out time increases the pressure reached in the reactor coolant system during the loss of feedwater transient.

Intuitively, it would appear that the possibility of reaching these high reactor coolant system pressures during a loss of main feedwater is extremely small. After all, the loss of main feedwater transient and some common-mode reactor protection system failure must occur simultaneously. Electric Power Research Institute report NP-2230 (1982) calculated a frequency of 0.15/yr for total loss of main feedwater events, based on from 36 operating PWRs. The error in this data is not known, because all loss of feedwater events are not reported. The failure of the reactor trip circuit breakers, the interrupting device of the reactor protection system, has occurred many times at operating plants. Data from NUREG-1000, "Generic Implications of ATWS Events at the Salem Nuclear Power Plant" (1983), show that out of 16,000 breaker demands at pressurized water reactor plants, a total of 53 failures had occurred.

4.7.4 Operational Occurrences

4.7.4.1 Salem ATWS

Simultaneous failures of the reactor trip breakers occurred at the Salem nuclear plant on February 22, 1983. The unit was operating at 20% power with one main feed pump in service. The second main feed pump was at minimum speed in preparation for continued power escalation. The operators were in the process of transferring loads from offsite power to the unit generator. During the transfer, a limit switch failed, causing the loss of one of the nonvital buses. Immediate equipment losses included one reactor coolant pump, control power to the operating main feedwater pump, control room lighting, and a 125-Vac miscellaneous distribution panel.

The loss of the distribution panel caused a loss of nonvital indications in the control room, which included the main feedwater pump indications and the steam generator panel (feed flows and steam flows). However, steam generator water level indications were still available.

The loss of main feedwater resulted in decreasing steam generator levels, and the low-low level trip setpoint was reached. This resulted in a trip signal being generated by the reactor protection system. However, the two series reactor trip circuit breakers failed to open. After evaluating the deteriorating plant conditions, the operator manually tripped the plant. The operator took action 3.5 seconds after the trip signal generated by the reactor protection system, thereby masking the failure of the trip breakers to open automatically. Since the reactor tripped when the operator actuated the manual trip switch, plant personnel did not suspect a problem with the reactor trip system, and, therefore, the ATWS went unnoticed until February 25, 1983.

On February 25, 1983, Salem was operating at 12% reactor power with the feedwater system in manual control. Difficulty in controlling steam generator levels was experienced, and the level in one of the four steam generators dropped to the low-low level reactor trip setpoint. Again, the reactor trip circuit breakers failed to open. The operator, after observing the first-out annunciator, announced on the plant paging system that a plant trip had occurred.

Another operator in the control room noticed that the reactor had not tripped, as indicated by the unlit rod bottom lights. In addition, the turbine had not tripped as expected. The shift supervisor monitored the steam generator levels at this time and noticed that they were at the low-low level trip setpoint (18%). He then directed the reactor operator to manually trip the plant. The operator tripped the plant 23 seconds after the original trip signal was generated.

The shift supervisor was concerned that a failure of the first-out annunciator system or of the reactor protection system had occurred. The instrumentation department was called to perform tests to determine the apparent problem with the indications described above. After the steam generator level bistables and the protection system were verified to be operating properly, tests were performed on the reactor trip breakers. When the trip breakers failed to open when demanded by the protection system, it was determined that an ATWS had occurred.

4.7.4.2 Breaker Malfunction

In both events at Salem, the reactor trip circuit breakers failed to function as designed. Figure 4.7-2 shows the reactor trip circuit breaker design at the time of the events. During normal operations, the circuit breakers are closed, supplying power to the control rod drive mechanisms. Each circuit breaker's undervoltage coil is energized and holds the main trip shaft in position as shown. The power keeping the undervoltage coil energized is controlled by the RPS.

When a trip signal is generated through the appropriate logic (two out of three or two out of four), the RPS de-energizes the undervoltage coil, which releases the main trip shaft. The spring shown directly above the undervoltage coil pulls on the arm it is attached to, causing the main trip shaft to rotate in the counterclockwise direction. When this shaft rotates, it allows the trip spring to pull the top portion of the trip bar to the left, which opens the reactor trip breaker.

Opening the reactor trip circuit breakers removes power from the power cabinets, de-energizing the stationary and movable grippers, and allowing the rods to fall into the core. The undervoltage coil provides a fail-safe feature of the reactor protection system: if a loss of power to the reactor protection system should occur, the undervoltage coils would de-energize, and the reactor trip breakers would open as described above. In the Salem ATWS, the undervoltage coils operated properly, but because of mechanical interference, the reactor trip circuit breakers failed to open as designed.

In addition to the undervoltage coil, each reactor trip breaker has an associated shunt trip coil. The shunt trip coil is normally de-energized when the breaker is closed. To open the breaker with the shunt trip coil, it must be energized. Energizing the coil pulls the shunt trip lever down. As this lever moves down, it comes in contact with the main trip shaft, which is forced to rotate in the counterclockwise direction. As explained above, this starts the chain of events which causes a reactor trip.

In the original Westinghouse design, the remote reactor trip switch opens the reactor trip circuit breaker by energizing the shunt trip coil, while simultaneously de-energizing the undervoltage coil. This manual trip feature allowed the operator to trip the reactor from the control room during both ATWS events at Salem.

The incident that occurred at Salem resulted in increased surveillances of reactor trip breakers to ensure operability. During surveillance testing at McGuire in July of 1987, one reactor trip breaker failed to open when tripped from the control room. It was found to have a defective weld on the trip shaft, which resulted in the mechanical binding of the trip shaft. This prevented the breaker from opening.

Upon further investigation, the other trip breakers at the McGuire station were found to have defective welds on their trip shafts. NRC Bulletin 88-01 was issued on February 5, 1988, to alert utilities using Westinghouse DS model trip breakers that a potential problem existed with this design.

4.7.5 Plant Modifications

4.7.5.1 Reactor Trip Breakers

As shown in Figure 4.7-2, the original Westinghouse design provided only one means by which the RPS would automatically open the reactor trip breakers: the de-energizing of the undervoltage coils. In the aftermath of the Salem events, trip breaker operation was modified to provide redundant means of automatically opening the breakers. With the modification, shown in Figure 4.7-3, the reactor protection system both energizes the shunt trip coil and de-energizes the undervoltage coil for each breaker when trip logic is satisfied.

4.7.5.2 ATWS Rule Requirements

10CFR50.62, published in 1984 and commonly referred to as "the ATWS rule," imposed new equipment requirements for all PWRs, as discussed in the following paragraphs.

Diverse Trip System

Combustion Engineering (CE) and Babcock and Wilcox (B&W) designed pressurized water reactors are required to have a second, diverse trip system. The system is required to be independent of the RPS from the sensor outputs to the CRDM power supplies. The diverse trip system has been imposed as a defense-in-depth measure for CE and B&W plants because of the relatively high percentage of fuel cycle time those plants are expected to operate with positive or slightly negative MTCs (in accordance with analyses performed by the reactor plant designers at the time of the ATWS rule). If an ATWS occurs when the MTC is positive or insufficiently negative to limit the reactor power and the associated increase in reactor coolant pressure, ATWS mitigation systems are likely to be ineffective. Westinghouse designed plants have been excluded from this requirement because of their larger pressurizer safety valves and relatively smaller expected percentage of fuel cycle time with positive or only slightly negative MTCs. (Refer to the discussion in section 4.7.3 of this chapter regarding the impacts of MTC and pressurizer relief valve capacity on the severity of an ATWS.)

A typical B&W diverse trip system interrupts power to the CRDMs when a very high reactor coolant system pressure setpoint has been reached. The very high pressure setpoint reflects the coolant expansion and high pressure expected during an ATWS event.

ATWS Mitigation System

Paragraph (c) of 10CFR50.62 requires each pressurized water reactor to have "equipment from sensor to final actuation device, that is diverse from the reactor trip system, to automatically initiate the auxiliary (or emergency) feedwater system and initiate a turbine trip under conditions indicative of an ATWS. This equipment must be designed to perform its function in a reliable manner and be independent (from sensor output to the final actuation device) from the existing reactor trip system."

In response to the ATWS rule, an ATWS mitigation system has been installed in each PWR to provide a backup to the reactor trip system and the engineered safety features actuation system for initiating a turbine trip and actuating the auxiliary feedwater system in the event of an ATWS. The system is typically non-safety-related, powered by non-Class 1E source, and microprocessor based. Various signals, such as high reactor coolant system pressure and low steam generator level, can be used as indications of an ATWS event. Two examples of ATWS mitigation systems are described below.

The Trojan ATWS mitigation system actuating circuitry (AMSAC), shown in Figure 4.7-4, starts the turbine-driven and diesel-driven auxiliary feedwater pumps and trips the main turbine if the narrow-range steam generator levels drop below the low-low level setpoint (11.5%) for at least 25 seconds in three of the four steam generators within the first 6 minutes after the turbine load has exceeded 40%.

The Indian Point Unit 3 AMSAC (see Figure 4.7-5) performs the same functions as the system described above. However, instead of steam generator narrow-range levels, main feedwater flows are supplied as inputs. If main feedwater flows drop below 21% in three out of four channels for a preset length of time (depending on power level), and power has been greater than 40% as indicated by turbine impulse pressure, the turbine is tripped, the auxiliary feedwater system is actuated, and the steam generator blowdown and sample lines are isolated. The signal is maintained for 40 seconds or for as long as the activation criteria are met. The 40-second timer maintains the AMSAC initiation signal to ensure that the necessary actions occur under changing conditions of power and feedwater flow.

Because the design of the ATWS mitigation system utilizes application software and intelligent automation controllers, problems have been encountered with the system that are unlike others traditionally experienced at nuclear plants. For example, in December of 1992, the Indian Point Unit 3 AMSAC was found to be inoperable since July of 1992 because of a software problem resulting from significant deficiencies in maintenance, testing, and quality assurance of the system. The configuration for the system is maintained on a hard drive, and it automatically loads into memory upon boot-up. The hard drive failed to reboot during a surveillance test in May of 1992. The utility reinstalled the repaired hard drive after it was returned from the vendor. The configuration files had to be rebuilt from an uncontrolled copy of the files kept by a vendor technician, because the utility had not maintained a controlled copy. During performance of post-maintenance testing on the system, the automatic reboot function was tested. However, the AMSAC developed a faulty trip signal and failed the test. Subsequent to software manipulations made by the vendor to address the faulty signal, only the reboot function was tested. During the next scheduled surveillance test in December of 1992, it was discovered that the AMSAC auxiliary feedwater initiation was inoperable due to inadvertent misplacement of the the 40-second timer in the system software during the software manipulations that had been conducted during the previous July. The system software was corrected, and the AMSAC was returned to an operable status in January of 1993.

4.7.6 PRA Insights

4.7.6.1 Historical

The NRC staff evaluation of ATWS in NUREG-460, "Anticipated Transients Without Scram for Light Water Reactors" (1980), was one of the first applications of PRA techniques to an unresolved safety issue. The evaluation highlighted the relative frequency of severe ATWS events associated with various reactor types and estimated the expected reduction in frequency for various postulated plant modifications. The study also proposed quantitative goals for resolving this issue. Other notable examples of PRA applications to the ATWS issue are the NRC sponsored survey and critique of reactor protection systems (SAI, 1982), and the ATWS Task Force report summarized in SECY-83-293.

The RPS survey reviewed 16 reliability studies, most of them published PRAs, to compare the predicted failure probability per unit demand, the anticipated transient frequency, and the primary influences on RPS unavailability. There was a surprising degree of agreement among the 16 studies. A second study quantified the relative improvement to be gained by implementing a set of recommendations proposed by a utility consortium in an ATWS petition to the NRC. A third study, a value-impact evaluation of the risk reduction of generic plant classes, provided the basis for the final rule on ATWS (SECY-83-293).

A recently prepared draft NRC Office of Nuclear Regulatory Research report assesses whether the ATWS rule and other relevant Commission recommendations issued with the ATWS rule have been effective in achieving the desired outcomes. The report concludes that the ATWS rule and associated recommendations have been effective in having the required plant modifications installed, in reducing core damage frequency associated with ATWS, and in limiting the costs to licensees. Specifically:

- Hardware modifications required by the ATWS rule have been implemented at all PWRs, typically between 1986 and 1990, including the diverse means of tripping the turbine and initiating auxiliary feedwater at all plants and the diverse scram system at CE and B&W plants. The report notes that changes in fuel design to achieve longer operating cycles will result in less negative MTCs for a larger fraction of the cycle time, during which ATWS mitigation functions may be rendered ineffective. Fuel cycle changes that significantly increase the ATWS risk due to longer exposure to such MTCs may require compensatory measures consistent with the ATWS rule for Westinghouse plants.

- SECY-83-293 set a goal of 1.0E-05/RY for the core damage frequency associated with an unmitigated ATWS (referred to as P(ATWS)). This goal has been exceeded for all plant types; the average Westinghouse plant value is 6.4E-07/RY. The reduction in P(ATWS) has been greatly affected by the large decrease in the frequency of automatic trips (the initiating events for ATWSs) since the ATWS rule was invoked. Also, better than expected improvements in RPS reliability have been achieved for all reactor plant types.

- RPS reliability is related to reactor trip breaker reliability. As evidenced by NRC generic communications and industry group activities, circuit breaker problems continue to occur. Industry programs to maintain RPS reliability continue to be useful in limiting risk from ATWSs.

- However, RPS reliability estimates are subject to large uncertainties. RPS reliability requirements are so high and ATWS events are so rare that many more years of operating experience are needed to generate sufficient system demands to reduce current estimates of the uncertainty. The current uncertainty associated with RPS reliability argues for the continued application of the requirements of the ATWS rule.

- Costs associated with implementing the ATWS rule have been less than expected ($166M actual vs. $354M expected), largely due to fewer than expected spurious trips caused by ATWS mitigation equipment.

NUREG-1560, "Individual Plant Examination Program: Perspectives on Reactor Safety and Plant Performance" (1997), concludes that ATWS is not an important contributor to the total core damage frequency for almost all Westinghouse plants. The core damage frequency attributable to ATWS events is small in absolute terms for almost all plants, and constitutes a significant contribution to total core damage frequency (greater than 10%) for just two plants. Each of these plants, Beaver Valley 1 and Indian Point 3, operates with some or all of its power-operated relief valve block valves closed, thereby reducing the relief capacity of the reactor coolant system during the early stages of an ATWS and thus increasing the potential peak pressure reached.

4.7.6.2 Plant Event

On June 3, 1991, a low flow reactor trip signal was generated during the calibration of a reactor coolant system flow instrument at Harris Unit 1 (LER 400/91-010). The B reactor trip breaker opened as required, but the A trip breaker failed to respond. The failure was due to a failed circuit board (a result of previous improper maintenance). The board failure prevented the occurrence of the automatic undervoltage and automatic shunt trips of the associated reactor trip breaker. A manual trip was still available.

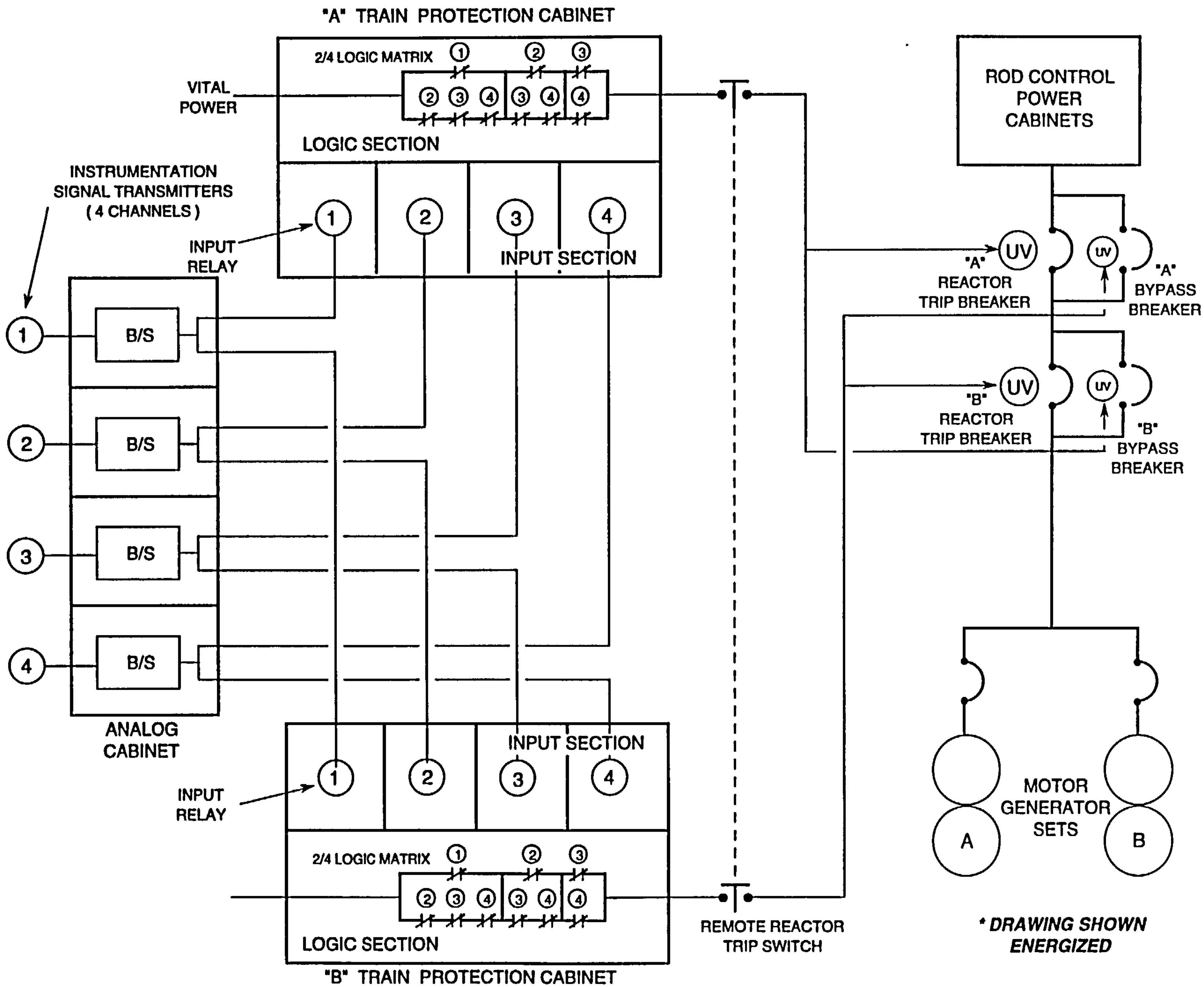
Assuming that both reactor trip breakers had failed to open, the conditional probability of subsequent core damage was estimated at 6.6E-06 for this event. Figure 4.7-6(a) shows the relative significance of this event compared to other postulated events at Harris Unit 1.

The model used to estimate the conditional core damage probability is shown in Figure 4.7-6(b). Assuming that an ATWS occurs with no manual trip (the operator does not perform the actions as directed by the emergency procedures), four sequences have end states of core damage. The dominant sequence for core damage is sequence 2, which assumes an ATWS, no operator action to insert the control rods, that primary pressure is limited, that the auxiliary feedwater system operates, but that emergency boration is not initiated.

4.7.7 Summary

The ATWS event is an analyzed plant transient that requires the automatic shutdown of the plant, combined with the failure of the reactor protection system to respond as designed. The Code of Federal Regulations requires that each pressurized water reactor must have equipment, that is diverse from the reactor trip system, that will initiate the auxiliary feedwater system and trip the turbine under conditions indicative of an ATWS. Therefore, utilities have installed ATWS mitigation systems that perform those functions.

As a result of the Salem ATWS, Westinghouse units added the automatic energizing of the shunt trip coil by the RPS. This modification provides a redundant means of opening the reactor trip breakers and potentially reduces the probability that a common-mode failure would prevent their opening.



4.7-1 Solid State Protection System

0791-59 A-1

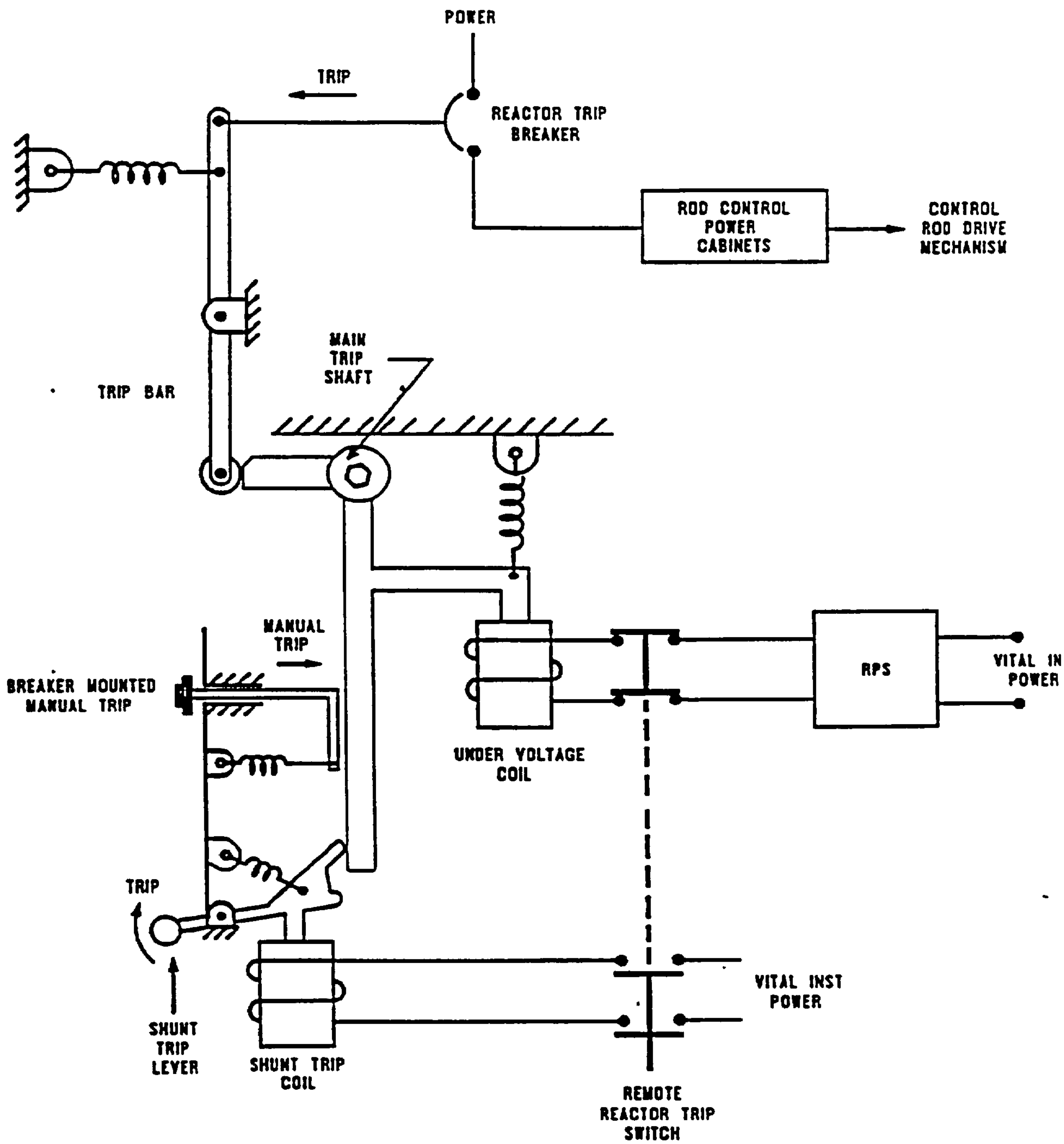


Figure 4.7-2 Reactor Trip Breaker

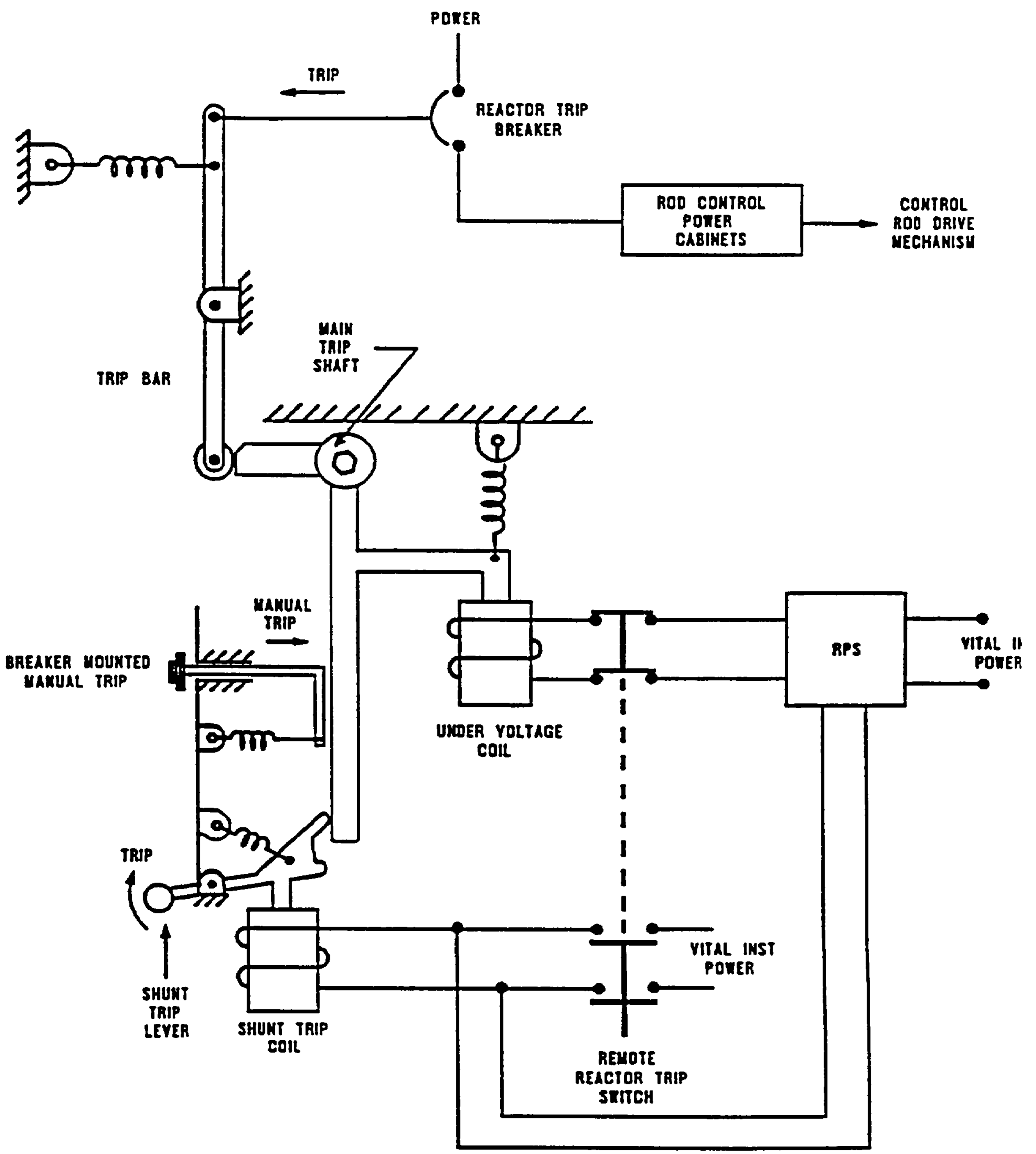


Figure 4.7-3 Reactor Trip Breaker Modification

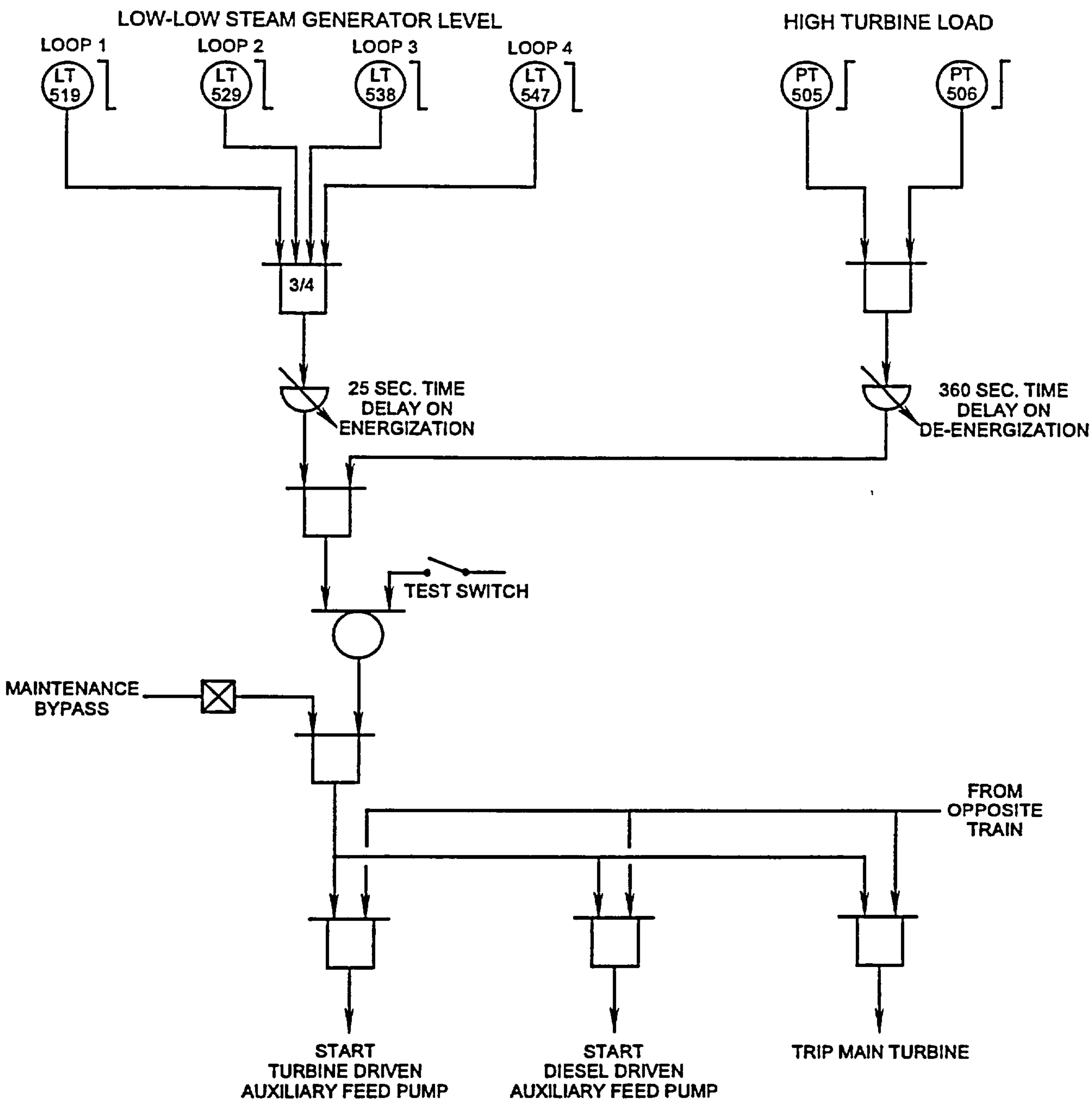


Figure 4.7-4 Trojan AMSAC Trip Circuit

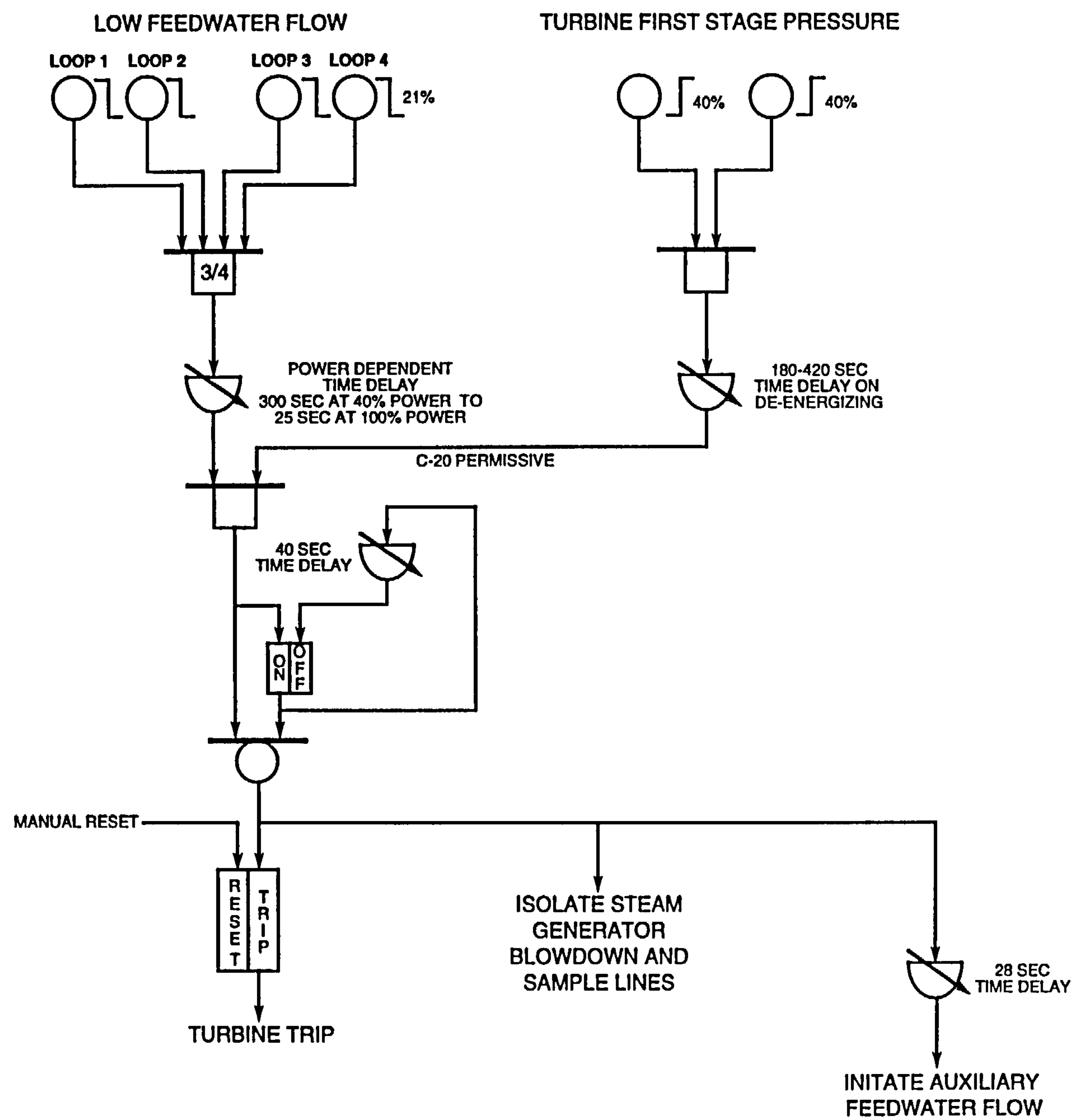


Figure 4.7-5 Indian Point Unit 3 AMSAC

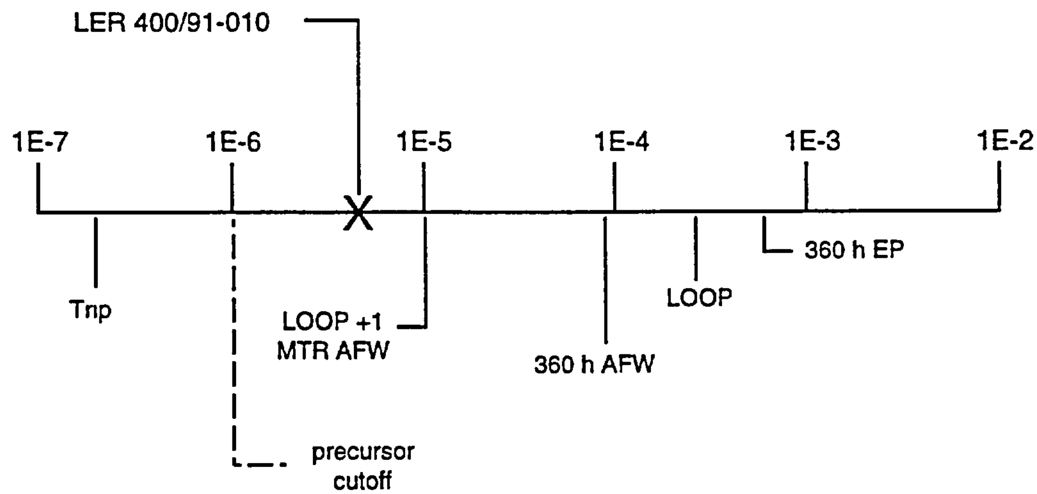


Figure 4.7-6(a) Relative Significance of Event Compared to Other Postulated Events at Harris 1

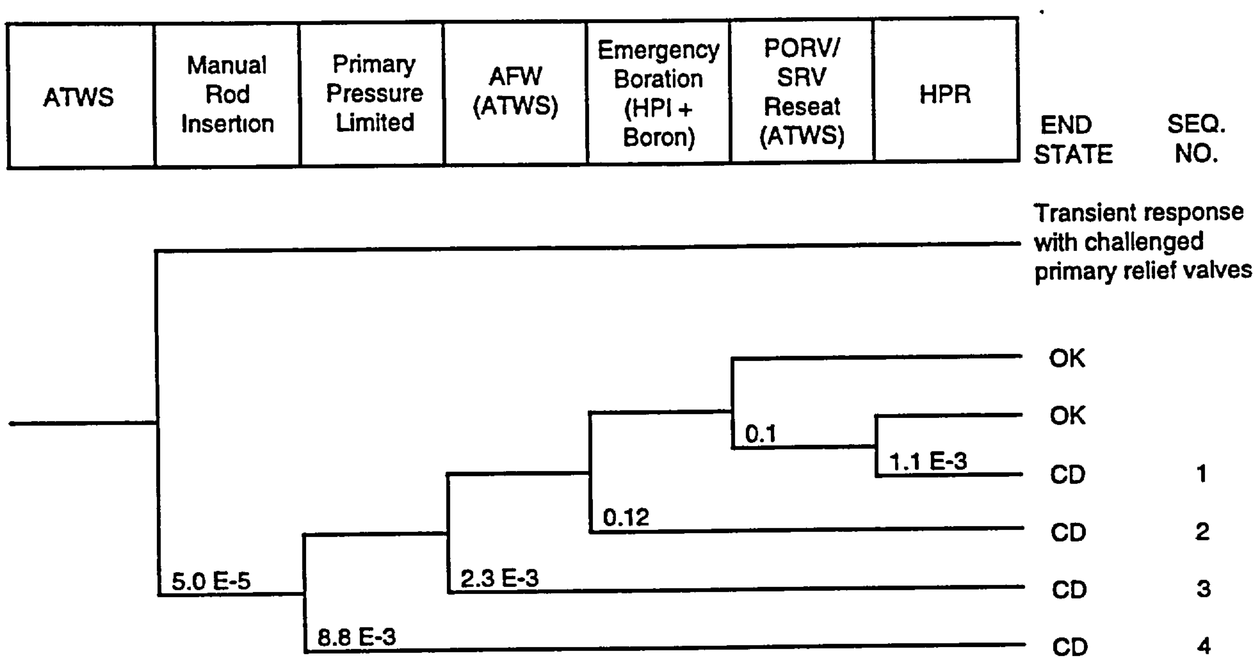


Figure 4.7-6(b) Model Used to Estimate the Conditional Core Damage Probability

Westinghouse Technology Advanced Manual

Section 4.8

Loss of All AC Power (Station Blackout)

TABLE OF CONTENTS

LIST OF FIGURES

4.8 LOSS OF ALL AC POWER (STATION BLACKOUT)

Learning Objectives:

1. Define the term "station blackout."
2. Describe the interim response by the NRC to the station blackout concern.
3. Describe the plant response necessary to mitigate the consequences of a station blackout using existing equipment.
4. Describe the regulatory requirements addressing the station blackout concern.
5. Describe the accident sequence that makes the loss of all alternating current (ac) power a major contributor to the total core damage frequency at some reactor plants.

4.8.1 Background and Basic Electrical Distribution Design

The General Design Criteria (GDC) in Appendix A of 10CFR50 establish the necessary design, fabrication, construction, testing and performance requirements for structures, systems, and components important to safety; these are the structures, systems and components that provide reasonable assurance that the facility can be operated without undue risk to the health and safety of the public. GDC 17, "Electric Power Systems," requires that onsite and offsite electric power systems be provided to permit the functioning of structures, systems and components important to safety. These structures, systems, and components are required to remain functional to ensure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences, and that the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents. GDC 17 specifies additional requirements for both the onsite and offsite electrical power distribution systems to ensure both their availability and reliability.

Figure 4.8-1 shows a typical offsite power system associated with a nuclear plant. During plant operation, power is supplied to the Class 1E (onsite) distribution system by the main generator. In the event of a unit trip, the preferred source of power to the onsite distribution system would be the offsite grid. If offsite power is available, an automatic transfer to the preferred power source ensures a continuous supply of ac power to equipment required to maintain the plant in hot standby and to remove decay heat from the core. If offsite power is not available due to external causes such as severe weather or equipment failure, the undervoltage condition sensed in the onsite distribution system initiates a transfer to the onsite (standby) power source. Figure 4.8-2 shows a typical onsite ac power distribution system. In the event that an undervoltage condition is sensed on the emergency buses following a unit trip, the system is designed to ensure the opening of all supply breakers to the buses, the disconnection of all unnecessary loads, the starting of the emergency diesel generators, and, when the machines have reached normal speed and voltage, the reconnection of all loads necessary to maintain the plant in a stable hot shutdown condition. If the onsite power sources are not available to re-energize the onsite distribution system, a station blackout (SBO) has occurred.

An electrical distribution system in conformance with GDC 17 was once considered sufficient to ensure that a commercial nuclear power plant would be operated without undue risk to the health and safety of the public. The simultaneous loss of both the offsite and onsite sources of ac power (a station blackout) was considered incredible and therefore did not have to be considered in plant design or accident analysis.

4.8.2 Plant Response

A station blackout is defined as "the complete loss of alternating current (ac) electric power to the essential and nonessential switchgear buses in a nuclear power plant (i.e., loss of the offsite electric power system concurrent with turbine trip and unavailability of the onsite emergency ac power system). Station blackout does not include the loss of available ac power to buses fed by station batteries through inverters or by alternate ac sources..., nor does it assume a concurrent single failure or design basis accident" (10CFR50.2). Because many safety systems required for reactor core cooling, decay heat removal, and containment heat removal depend on ac power, the consequences of a station blackout could be severe.

The immediate consequences of an SBO are not severe if it is not complicated by an accident such as a loss of reactor coolant, steam generator tube rupture, or loss of secondary coolant. If the SBO continues for a prolonged period, the potential consequences for the plant and public health and safety can be serious. The combination of core damage and containment overpressurization could lead to significant releases of fission products offsite. Any design basis accident in conjunction with an SBO would reduce the time to core damage and radioactive release.

The severity of an SBO for a pressurized water reactor (PWR) depends primarily on the combination of the duration of the power outage and the response of the reactor coolant pump (RCP) shaft seals (see Figure 4.8-3). During an SBO, the seals undergo the simultaneous loss of high pressure seal injection and of cooling water to the RCP thermal barriers. With no seal injection, due to the loss of power to the charging pumps, reactor coolant leaks up the RCP shafts. Because the charging pumps are unavailable, this leakage cannot be replaced. The loss of cooling to the RCP thermal barriers, due to the loss of power to the component cooling water pumps, means that the leaking coolant is at very high temperatures. The high temperature leakage can result in degradation of the seals, which might increase reactor coolant leakage up to several hundred gallons per minute. Without systems designed to operate independently of ac power, the only way to mitigate the consequences of an SBO is to minimize the loss of reactor coolant system (RCS) inventory and to quickly restore power to replenish the lost inventory. This will ensure the ability to remove decay heat from the core and to prevent fuel damage.

The severity of an SBO can be mitigated through a controlled cooldown of the RCS. This evolution is covered in the Westinghouse emergency response guidelines (ECA 0.0, "Loss of all AC Power"). The RCS pressure reduction that results from coolant contraction and inventory loss through the RCP seals significantly reduces seal leakage. The cooldown can be maintained as long as natural circulation (or reflux boiling once the system becomes saturated) in the RCS transfers decay heat from the core to the steam generators. The steam generators are available as a heat sink, as long as the power-operated relief valves and steam-driven auxiliary feed pump are available. Manual or local operation of these components may be required to different degrees, depending on specific plant designs. As the RCS pressure is reduced below the pressure of the cold-leg accumulators, they inject borated water to replenish lost inventory. Care must be taken not to let the RCS pressure decrease to the point that nitrogen from the accumulators enters the system. Nitrogen in the RCS could block the flow of water or steam through the steam generator tubes. Another problem associated with the RCS cooldown worthy of consideration is that, as the temperature is reduced, positive reactivity is added to the core due to the moderator temperature coefficient (MTC). Without ac power there is no means to add boric acid to the RCS to ensure an adequate shutdown margin until the accumulators are able to inject, and the potential exists for the core to return to criticality. This concern is most significant at the end of core life, when the MTC is most negative. In addition, the hot reactor coolant leaking from the RCS raises the temperature and pressure of the containment. Without ac power, there is no way to reduce containment temperature, and eventually containment integrity would be lost due to high pressure.

If a cooldown of the plant is not initiated, the loss of inventory through the RCP seals would continue at a high rate, which could even increase due to seal degradation, and eventually result in inadequate core cooling and damage. In either case, core uncovery and loss of containment integrity are inevitable unless ac power can be restored to permit RCS inventory control and containment heat removal.

4.8.3 Regulatory Developments

In 1975, WASH-1400, "Reactor Safety Study," determined that station blackout could be an important contributor to the total risk associated with nuclear power plant core damage initiators. This fact, combined with the increasing indications that onsite emergency power sources (diesel generators [DGs] in most cases) were experiencing higher than expected failure rates, led the NRC to designate the station blackout concern as an unresolved safety issue (USI). By designating the issue as a USI, it would receive priority in terms of study and resolution. USI A-44 was established in 1979, and the task action plan that followed focused on analyzing the frequency and duration of losses of offsite power and the probability of failure of onsite (emergency) ac power sources. Other areas of interest included the availability and reliability of decay heat removal systems independent of ac power and the ability to restore offsite power before normal decay heat removal equipment (equipment that relies on ac power) fails due to a harsh environment. The conclusions of the study would be used as a basis for further rule making and required design changes, if necessary to protect the public health and safety. The results of the station blackout study were published in NUREG-1032, "Evaluation of Station Blackout at Nuclear Power Plants" (June 1988).

Analysis of the reliability and availability of onsite power sources, primarily diesel generators, received the highest priority, because their relative unreliability probably was the deciding factor in designating the issue as a USI. It was felt that, if safety improvements were indeed necessary, it would be more feasible to identify and initiate improvements for onsite power sources than for either offsite power sources or onsite equipment that requires ac power to function. Offsite power source reliability is dependent on several factors, such as regional grid stability, the potential for severe weather conditions, and utility capabilities to restore power, which are difficult to control. Ultimately, the ability of a plant to withstand an SBO depends on the decay heat removal systems, components, instruments, and controls that are independent of ac power.

The SBO concern intensified in 1980 following license hearings for the operation of St. Lucie Unit 2 in southern Florida. The concern was that, with the plant location subject to periodic severe weather conditions (hurricanes) and questionable grid stability, the frequency of losses of offsite power would be much higher than for other plants. The Atomic Safety and Licensing Appeal Board (ASLAB) concluded that a station blackout should be considered a design-basis event for St. Lucie Unit 2. Since the task action plan for USI A-44 provided a considerable amount of time for studying the SBO concern, the ASLAB recommended that plants with station blackout likelihoods comparable to that of St. Lucie be required to ensure that they were equipped and their operators properly trained to cope with the event. NRR changed the construction permit for St. Lucie Unit 2 to include the station blackout in the design basis and required a modification to the Unit 1 design even though preliminary studies showed that the probability of a station blackout at St. Lucie was not significantly different than that for any other plant. Interim steps were taken by NRR to ensure that other operating plants were equipped to cope with an SBO until final recommendations were formulated regarding the USI.

Improvements to the auxiliary feedwater (AFW) system were already being initiated at PWRs, based on the lessons learned from the accident at Three Mile Island. A reliable AFW system with equipment that can operate independent of ac power is very important to the capability for coping with an SBO and for maintaining the plant in a safe shutdown condition.

Recommendations for improvements to emergency diesel generators had already been established, based on studies of DG reliability (NUREG/CR-0660), and were being implemented through licensing requirements for new plants and through technical specification improvements for licensed plants. It was recognized that improving DG reliability was the most controllable factor affecting the likelihood of an SBO and would serve to reduce the probability of occurrence.

Generic Letter 81-04 required licensees to verify the adequacy of or to develop emergency procedures and operator training to better enable plants to cope with an SBO, utilizing existing equipment and expedited restoration of power from either onsite or offsite sources.

4.8.4 French Design

In France, Electricite de France began to study the SBO problem as early as 1977 and has developed plant equipment and emergency procedures to bring a plant to safe shutdown conditions following the loss of all ac power. The 1300-MWe series of plants was originally designed for an SBO; and the 900-MWe series has been improved to meet the more stringent design requirements. Design features that the French have incorporated are shown in Figure 4.8-4. They include multiple turbine-driven emergency feedwater pumps to supply water to the steam generators and a turbine-driven electrical generator that starts automatically and supplies power to vital loads, such as a dedicated RCP seal injection pump to ensure seal integrity and to prevent the loss of RCS inventory. Other loads supplied from the emergency turbine generator include the instrumentation, controls, and lighting necessary to maintain the plant in a safe shutdown condition. The French emergency procedures allow the operators to identify the problem quickly, to maintain the plant in a safe shutdown condition, and to restore power to the unit from either offsite or another unit at the same site as soon as possible.

4.8.5 Station Blackout Rule

Based on the conclusions of the station blackout study published in NUREG-1032, 10CFR50.63, the "station blackout rule," was added to the Code of Federal Regulations in 1988. This rule requires that each nuclear power plant be able to withstand for a specified duration and to recover from an SBO. The specified duration is to be based on the redundancy and reliability of onsite emergency ac power sources, the expected frequency of losses of offsite power, and the probable time needed to restore offsite power. The rule further requires that each plant's systems and equipment be capable of maintaining core cooling and containment integrity in the event of an SBO for the specified duration. The capability for coping with an SBO was to be determined by an appropriate coping analysis.

To comply with 10CFR50.63, each licensee was required to submit to NRR the proposed SBO duration for its plant and the justification for its selection, a description of the procedures to be implemented for SBOs, and a list of proposed modifications to equipment and procedures necessary to assure the plant's capability to cope with an SBO for the specified duration.

The station blackout rule also allows a licensee to take credit for an alternate ac source. 10CFR50.2 defines an alternate ac source as an ac "power source that is available to and located at or nearby a nuclear power plant and meets the following requirements:

(1) Is connectable to but not normally connected to the offsite or onsite emergency ac power systems;

(2) Has minimum potential for common mode failure with offsite power or the onsite emergency ac power sources;

(3) Is available in a timely manner after the onset of station blackout; and

(4) Has sufficient capacity and reliability for operation of all systems for coping with station blackout and for the time required to bring and maintain the plant in safe shutdown...."

The station blackout rule states that an alternate ac source constitutes acceptable capability to withstand an SBO provided that the licensee performs an analysis which demonstrates that the plant has this capability, that the licensee demonstrates by test the time required to start and align the source, and that the alternate ac source meets certain capacity requirements. If the alternate ac source meets those requirements and can be demonstrated to be available to power the shutdown buses within 10 minutes of the onset of an SBO, then no coping analysis is required.

Regulatory Guide 1.155, "Station Blackout," also issued in 1988, provides guidance for meeting the requirements of 10CFR50.63. The guide contains guidance on:

- Maintaining an individual emergency diesel generator target reliability of 0.95 or 0.975 per demand and assumes that, as long as the unavailability of DGs due to maintenance and testing is not excessive, the maximum DG failure rate would result in overall reliability for the emergency power system;
- Establishing a DG reliability program with test, maintenance, data collection, and management oversight elements to maintain the selected DG target reliability;

- Developing procedures and training to cope with an SBO;
- Selecting a plant-specific minimum acceptable blackout duration capability of 2, 4, 8, or 16 hours based on the reliability and redundancy of onsite emergency ac power sources, the expected frequency of losses of offsite power based on the independence of offsite power sources and the plant's susceptibility to severe weather, and the probable time needed to restore offsite power;
- Evaluating a plant's capability to cope with a blackout based on the selected duration capability; and
- Completing modifications as necessary to cope with a blackout.

The guidance is structured so that the lower emergency diesel generator target reliability (0.95) is selected at plants where the DGs are demonstrated to be relatively unreliable, and that longer blackout coping durations are selected at plants with relatively unreliable DGs and at plants that are more susceptible to losses of offsite power.

All licensees have completed actions to comply with the station blackout rule. As a result of the rule, all plants have established blackout coping and recovery procedures, completed training in accordance with these procedures, established emergency diesel generator reliability programs which have improved DG reliability, ensured a four- or eight-hour coping capability, and implemented modifications as necessary to cope with an SBO. Modifications include additional DGs (some as onsite emergency ac power sources and some as alternate ac sources); modifications to existing DGs and DG auxiliaries; the addition of or modifications to gas turbine generators, added cross-ties between buses, units, and power sources; and changes to dc load-shed procedures.

In accordance with the regulatory assessment requirement of the station blackout rule, the NRC has completed safety evaluations of licensee compliance actions for all plants. In addition, the NRC completed eight pilot inspections prior to 1995 to verify the adequacy of licensee programs, procedures, training, equipment and systems, and supporting documentation in implementing the station blackout rule. Because these inspections found only minor problems, the NRC staff concluded that additional inspections to verify adequate implementation of the rule were unnecessary.

4.8.6 PRA Insights

4.8.6.1 Historical

Because of the dependence on electrical power by most of the systems involved in the mitigation of accidents, the electrical distribution system can be a major contributor to core damage frequency. This was first made evident in WASH-1400. SBO sequences account for greater than 10% of overall plant core damage frequency for 45 of 69 operating pressurized water reactors. According to NUREG-1560, "Individual Plant Examination Program: Perspectives on Reactor Safety and Plant Performance" (1997), the most influential factors on SBO-attributable core damage frequency for Westinghouse plants are the number of emergency ac power sources, battery depletion time, how coolant losses due to RCP seal failure are modeled, and whether modifications such as RCP seals with high-temperature o-rings or the provision of alternative seal cooling have been made.

A major accident sequence has a station blackout as the initiator, followed by RCP seal failure, leading to a small-break loss of coolant accident. This sequence leads to core damage because of the unavailability of the high pressure injection system for replenishing the reactor coolant inventory.

Other sequences involving electrical power problems as initiators involve the failure of the auxiliary feedwater system, the failure of a pressurizer power-operated relief valve (PORV) to shut, and the failure of a PORV to open to enable bleeding and feeding. Causes of loss of power initiators include:

1. The failure of DGs to start,
2. The failure of DGs to run after starting,
3. The failure to recover ac power,
4. The unavailability of DGs due to testing or maintenance, and
5. A local inverter fault which fails the automatic actuation of the auxiliary feedwater system.

A report prepared by the NRC Office of Nuclear Regulatory Research, "Final Report: Regulatory Effectiveness of the Station Blackout Rule" (2000), assesses whether the station blackout rule has been effective in achieving the desired outcomes. The report concludes that, although there are opportunities to clarify SBO-related regulatory documents, the rule is effective, and industry and NRC costs to implement the rule were reasonable. The report provides the following detailed conclusions:

- The reduction in the mean SBO-attributable core damage frequency was approximately 3.2E-05/RY, slightly better than the expected 2.6E-05/RY. As a result of improvements made to address the station blackout rule, more plants achieved a lower SBO-attributable core damage frequency than expected, and the plants with the greatest numbers of losses of offsite power from plant events and extremely severe weather conditions made the largest improvements, most by providing access to alternate ac power supplies. In addition, with some exceptions, the observed DG reliability performance exceeds the mean DG reliability assumptions of probabilistic risk assessments and individual plant examinations, indicating that SBO-attributable core damage frequencies are smaller than those stated in those risk assessments. As the blackout rule risk reduction objectives have been exceeded, further investigation of strategies for reducing SBO frequencies may not be needed.

- Before the blackout rule was issued, only 11 of 78 plants surveyed had a formal emergency DG reliability program, 11 of 78 plants had a unit average DG reliability of less than 0.95, and 2 of 78 had a unit average DG reliability of less than 0.90. Since the blackout rule was issued, all plants have established DG reliability programs which have improved DG reliability. Only 3 of 102 operating plants have a unit average DG reliability of less than 0.95, considering actual performance on demand and unavailability due to maintenance and testing with the reactor at power. However, unavailability due to maintenance and testing at power is greater than expected and explains why licensees appear to be having difficulty meeting the 0.975 target reliability. Decreased DG reliabilities and/or increased maintenance and testing unavailabilities erode the risk benefits obtained from implementing the blackout rule.

- Operating experience indicates that modifications implemented in response to the blackout rule have increased defense in depth against power interruptions. Turkey Point's ability to ride out Hurricane Andrew in 1992 illustrates this point; there is some likelihood that the plants would have lost all ac power during a 2.5-hour interval a few days after the storm without two emergency DGs added to address the blackout rule. Blackout-rule modifications also provide defense in depth to compensate for potential degradation of offsite ac power sources that may result from deregulation of the electric power industry or longer-than-expected times for recovery of offsite power following extremely severe weather.

- A value-impact analysis indicates that the rule's outcome was within the expected range of reductions in public dose per dollar of cost. Not expected was the addition of 19 power supplies at a cost of $174M. However, the addition of power supplies has resulted in significant plant-specific reductions in core damage frequency and has provided significant monetary benefits associated with greater operating flexibility resulting from longer allowed outage times for DGs.

4.8.6.2 Plant Event

In March of 1990, Vogtle Unit 1 experienced a loss of all ac power for a period of approximately 36 minutes. The blackout was caused by a combination of human errors and equipment failures.

Prior to the loss of power, the plant was shutdown with the reactor vessel head installed, but with the head bolts de-tensioned. The reactor coolant system was drained to mid-loop for maintenance. Train A of the residual heat removal system was maintaining primary temperature. The B diesel generator was disassembled for maintenance, and the B reserve auxiliary transformer (RAT) was tagged out for maintenance. Offsite power was being supplied by the A RAT.

At approximately 9:20 a.m., a truck toppled a tower onto the A RAT, causing a loss of offsite power to Unit 1. The A diesel generator started but did not continue to run. The diesel trip signals were bypassed, and the diesel was emergency started at 9:56. During the period when ac power was not available, the reactor coolant system temperature increased by 46°F (an equivalent heatup rate of 1.3°F/min). After power was restored, the A train of the residual heat removal system was restarted to reduce the primary temperature.

The Vogtle station blackout occurred after the plant had been shut down for a period of time, so the decay heat level was very low. Had the blackout initiated with a larger decay heat load, the rate of temperature increase would have been much faster. In this case the shutdown plant conditions and the short duration of the blackout minimized the consequences of the event (RCP seals were not threatened). Nevertheless, the Vogtle Unit 1 blackout was very similar to core damage sequences which appear in plant PRAs, and more severe initial conditions or a longer blackout duration could have resulted in core damage.

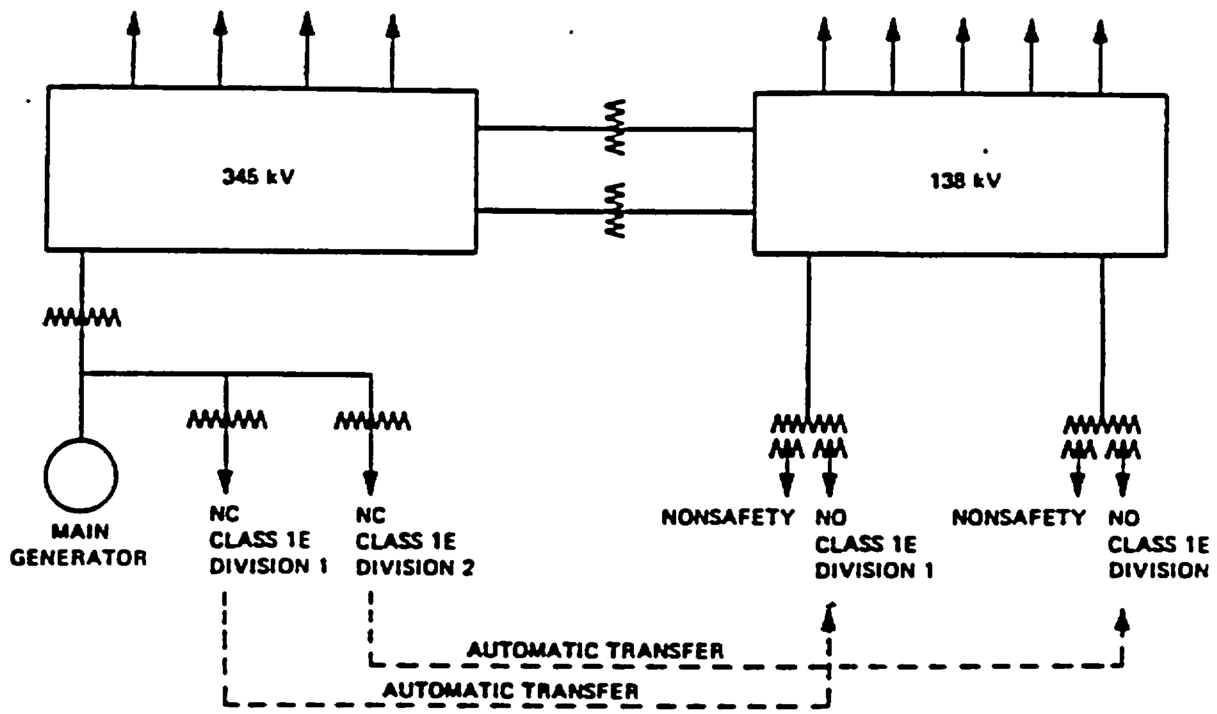


Figure 4.8-1 Typical Offsite AC Distribution

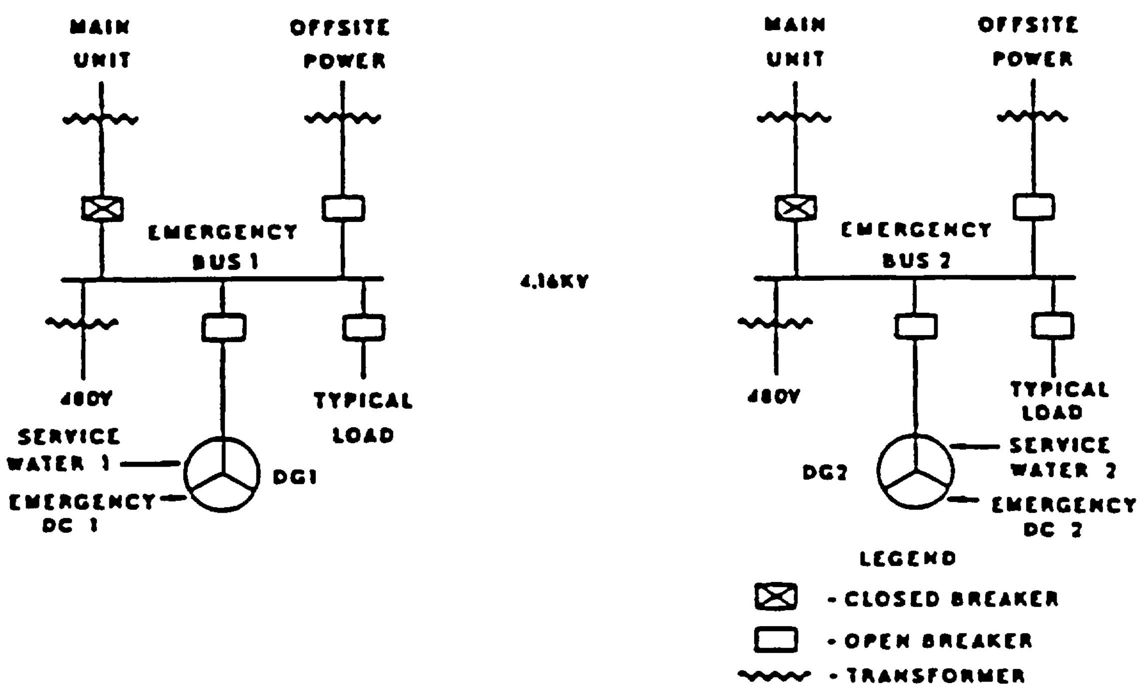


Figure 4.8-2 Typical Onsite AC Distribution System

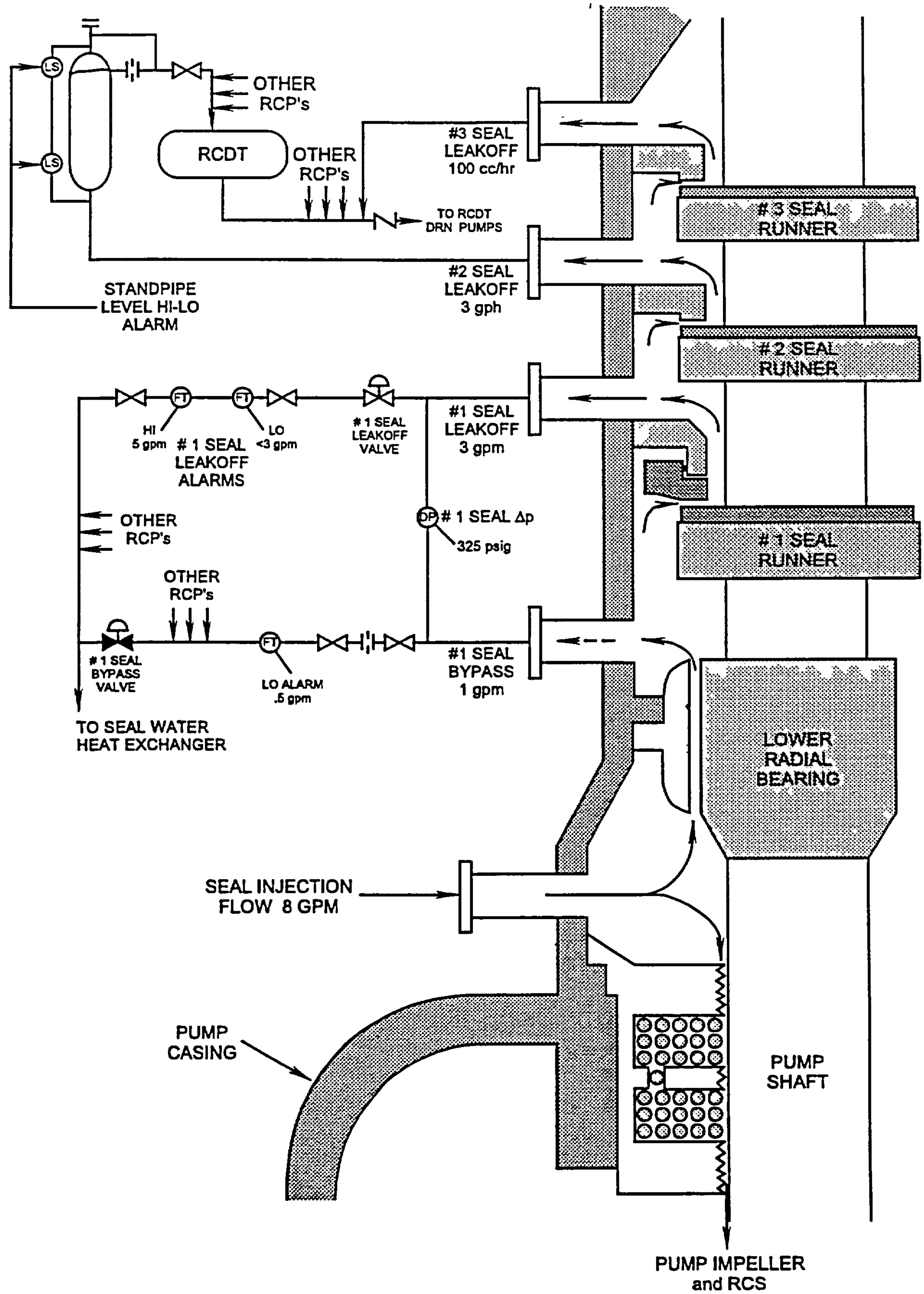


Figure 4.8-3 Seal Flow Diagram

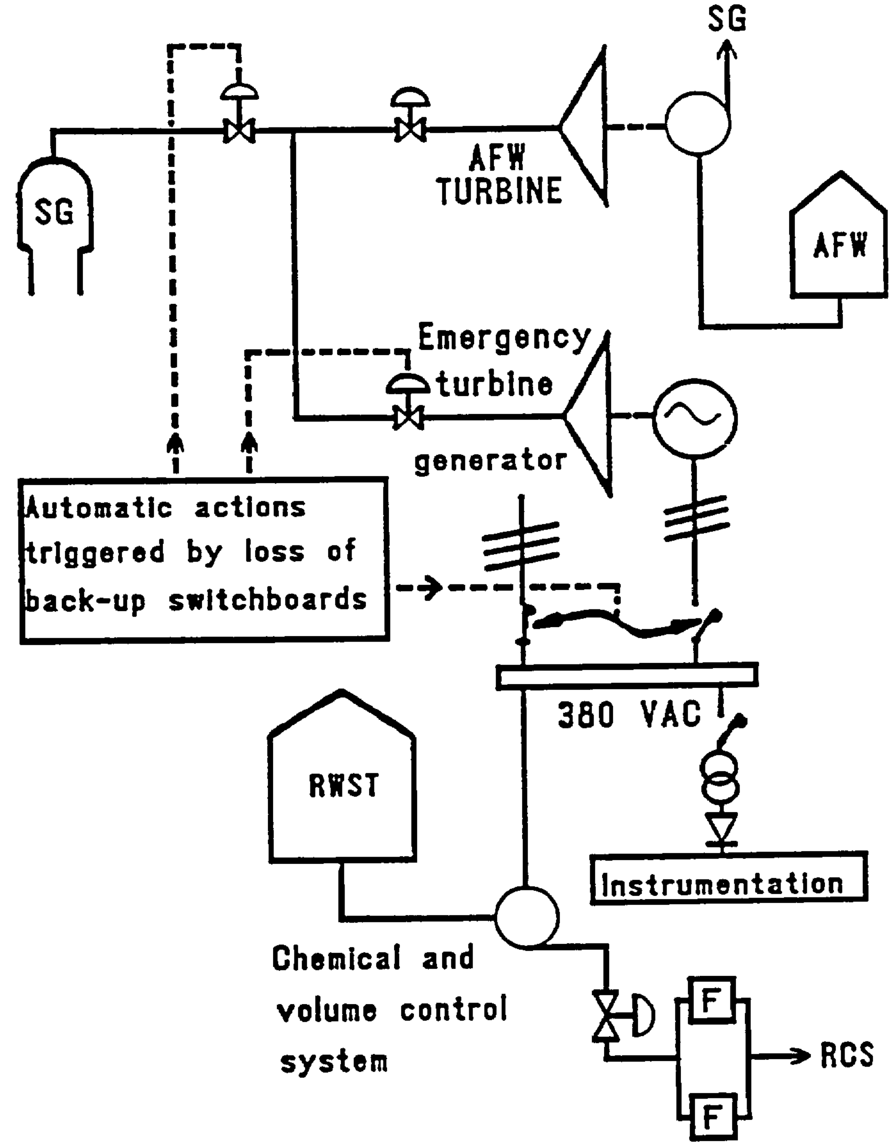


Figure 4.8-4 French Design for Safe Shutdown During a Blackout

Westinghouse Technology Advanced Manual

Section 4.9

Shutdown Plant Problems

TABLE OF CONTENTS

LIST OF FIGURES

4.9 SHUTDOWN PLANT PROBLEMS

Learning Objectives:

1. State the purposes of the residual heat removal (RHR) system.
2. Describe the alignment and operation of the RHR system during its shutdown cooling mode of operation.
3. Describe design features of the RHR system which could reduce its reliability when it is being used for decay heat removal.
4. Describe the consequences of losing decay heat removal capability when the reactor is in cold shutdown.

4.9.1 Introduction

One of the most significant problems associated with a shutdown reactor is the removal of the heat being produced by radioactive decay of the fission products produced during reactor operation. The General Design Criteria in Appendix A of 10CFR50 address this problem by requiring a residual heat removal system to transfer fission product decay heat and other residual heat from the reactor core at a rate such that specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary are not exceeded. Suitable redundancy in components and features, and suitable interconnections, leak detection, and isolation capability shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

The core damage frequency associated with the inability to remove decay heat from the reactor core was demonstrated to be significant in the results of the Reactor Safety Study (WASH-1400). The overall probability of core damage in the first generation of large commercial power reactors was higher than had been expected (about 5×10^{-5} as compared to 1×10^{-6} per reactor year). Inadequate reliability of the decay heat removal system (specifically following a small-break loss of coolant accident) was shown to be responsible for a substantial portion of the overall probability of core damage. This fact, combined with repetitive events resulting in the inadequate or complete loss of decay heat removal capability in operating plants, led the NRC to designate shutdown decay heat removal requirements as an Unresolved Safety Issue (USI A-45). Under the established task action plan, the NRC has studied the adequacy of systems for safely removing decay heat from a reactor core during shutdown and to assess the value and the impact of alternative measures for improving the reliability of the decay heat removal function.

4.9.2 RHR System Description

The purposes of the residual heat removal system are as follows:

1. Removes decay heat from the core and reduces the temperature of the reactor coolant system (RCS) during the second phase of plant cooldown,
2. Serves as the low pressure injection portion of the emergency core cooling systems (ECCSs) following a loss of coolant accident, and
3. Transfers refueling water between the refueling water storage tank and the

refueling cavity before and after refueling.

The RHR system transfers heat from the reactor coolant system to the component cooling water system. During shutdown plant operations, the RHR system is used to remove the decay heat from the core and to reduce the temperature of the reactor coolant to the cold shutdown temperature (less than 200°F). The cooldown performed by the RHR system (from 350°F to less than 200°F), is referred to as the second phase of cooldown. The first phase of cooldown is accomplished by the auxiliary feedwater (AFW) system, the steam dump system, and the steam generators.

Once the plant is in cold shutdown, the RHR system will maintain RCS temperature until the plant is started up again. The residual heat removal system also serves as part of the emergency core cooling system during the injection and recirculation phases of a loss of coolant accident. The residual heat removal system is used to transfer refueling water between the refueling water storage tank and the refueling cavity before and after the refueling operations.

The residual heat removal system, as shown in Figure 4.9-1, consists of two heat exchangers, two residual heat removal pumps, and the associated piping, valves, and instrumentation necessary for operational control. The inlet line to the residual heat removal system for the second phase of cooldown is connected to the hot leg of reactor coolant loop 4, and the return lines are connected to each cold leg of the reactor coolant system. These return lines also function as the emergency core cooling system low pressure injection lines.

The RHR pump suction line from the reactor coolant system is normally isolated by two series motor-operated valves (8701 and 8702). The suction line has a relief valve located downstream of the isolation valves; all three valves are located inside the containment. Each RHR supply to the RCS cold legs is isolated from the reactor coolant system by two check valves located inside the containment, and each RHR pump discharge line is can be isolated by a normally open motor-operated valve (8809A or 8809B) located outside the containment. These motor-operated valves are part of the emergency core cooling system and receive confirmatory open signals from the engineered safety features actuation system. During the second phase of cooldown, reactor coolant flows from the RCS to the residual heat removal pumps, through the tube side of the RHR heat exchangers, and back to the RCS. The heat from the reactor coolant is transferred to the component cooling water, which is circulating through the shell side of the RHR heat exchangers.

If one of the two pumps or one of the two heat exchangers is not operable, the ability to safely cool down the plant is not compromised; however, the time required for the cooldown is extended. The water chemistry requirements for the residual heat removal system are the same as those for the reactor coolant system. Provisions are made for extracting samples from the flow of reactor coolant downstream of the RHR heat exchangers for analysis. A local sampling point is also provided in each residual heat removal train between the pump and its associated heat exchanger.

To ensure the reliability of the RHR system, the two residual heat removal pumps are powered from separate vital electrical power supplies. If a loss of offsite power occurs, each vital bus is automatically transferred to a separate emergency diesel power supply. A prolonged loss of offsite power would not adversely affect the operation of the residual heat removal system.

The residual heat removal system is normally aligned to perform its safety function. Therefore, no valves are required to change position. For the RHR system to perform its safety function, the RHR pumps must start when the engineered safety features actuation signal is received, and the pressure in the reactor coolant system must drop below the discharge pressure of the RHR pumps.

The materials used to fabricate the RHR system components are in accordance with the applicable ASME code requirements. All parts or components in contact with borated water are fabricated of or clad with austenitic stainless steel or an equivalent corrosion-resistant material.

4.9.2.1 Component Description

Residual Heat Removal Pumps

Two pumps are installed in the residual heat removal system. The pumps are vertical, centrifugal units with mechanical seals on the shafts. These seals can be cooled by either component cooling water or service water, depending on the plant design. All pump surfaces in contact with reactor coolant are manufactured from austenitic stainless steel or an equivalent corrosion-resistant material. The pumps are sized to deliver reactor coolant flow through the residual heat exchangers to meet the plant cooldown requirements.

The residual heat removal pumps are protected from overheating and loss of suction flow by minimum flow bypass lines that assure flow to the pump suctions for pump cooling. A control valve located in each minimum flow line (610 or 611) is regulated by a signal from the flow transmitter located in each pump discharge header. Each control valve opens when the RHR pump discharge flow is less than 500 gpm and the pump is running, and closes when the flow exceeds 1000 gpm or the pump is not running. A pressure sensor in each pump header provides a signal for an indicator on the main control board. A high pressure annunciator alarm is also actuated by the pressure sensor.

Residual Heat Removal Heat Exchangers

Two heat exchangers are installed in the system. The heat exchanger design is based on the heat load and the temperature difference between the reactor coolant and component cooling water 20 hours after the reactor has been shut down. The temperature difference between these two systems at that time is at its minimum, thus accounting for the minimum heat transfer capability.

The heat exchangers are of the shell and U-tube type. Reactor coolant circulates through the tubes, while component cooling water circulates through the shell. The tubes are welded to the tube sheet to prevent leakage of reactor coolant.

Residual Heat Removal System Valves

Each valve that performs a modulating function is equipped with two stem packing glands and an intermediate leakoff connection that discharges to the drain header.

Manual and motor-operated valves have backseats to facilitate repacking and to limit stem leakage when the valves are open. Leakage connections are provided where required by valve size and fluid conditions.

The suction line from the reactor coolant system is equipped with a pressure relief valve sized to relieve the combined flow of all the charging pumps at the relief valve set pressure. This relief valve is installed to provide overpressure protection for the reactor coolant system under solid plant operations. Each discharge line to the reactor coolant system is equipped with a pressure relief valve to relieve the maximum possible back-leakage through the check valves which separate the residual heat removal system from the reactor coolant system.

The residual heat removal system includes two isolation valves (8701 and 8702) in series in the inlet line between the high pressure reactor coolant system and the lower pressure RHR system. Each isolation valve is interlocked with one of two independent reactor coolant system pressure transmitters. These interlocks prevent the valves from being opened unless the reactor coolant system pressure is less than 425 psig to ensure that the RHR system is not over pressurized. After the valves are open, another set of interlocks will cause the valves to automatically close when the reactor coolant system pressure increases to approximately 585 psig.

4.9.2.2 System Features and Interrelationships

Plant Cooldown

The initial phase of reactor cooldown is accomplished by transferring heat from the RCS to the steam and power conversion system via the steam generators. The second phase of cooldown starts with the RHR system being placed in operation. The RHR system is placed in operation approximately four hours after reactor shutdown, when the temperature and pressure of the RCS are approximately 350°F and 425 psig, respectively.

Assuming that two heat exchangers and two RHR pumps are in service, and that each heat exchanger is being supplied with component cooling water at its design flow rate and temperature, the RHR system is designed to reduce the temperature of the reactor coolant from 350°F to 140°F within 16 hours. The heat load handled by the residual heat removal system during the cooldown includes residual and decay heat from the core and reactor coolant pump heat. The design heat load is based on the decay heat fraction that exists at 20 hours following reactor shutdown from extended operations at full power. Coincident with operation of the residual heat removal system, a portion of the reactor coolant flow may be diverted from downstream of the residual heat removal heat exchangers to the chemical and volume control system (CVCS) low pressure letdown line for cleanup and/or pressure control.

Startup of the residual heat removal system includes a warmup period during which the reactor coolant flow through the heat exchangers is limited to minimize thermal shock to the heat exchangers. The rate of heat removal from the reactor coolant is manually controlled by regulating the coolant flow through the RHR heat exchangers.

The component cooling water is supplied at a constant flow rate to the RHR heat exchangers. The temperature of the return flow can be controlled by manually adjusting the control valves (606, 607) downstream of the heat exchangers coincident with manual adjustment of the heat exchanger bypass valve (HCV-618).

The reactor coolant system cooldown rate is limited by equipment cooldown rates based on allowable stress limits. The available cooldown rate can be affected by the operating temperature limits of the component cooling water system. As the reactor coolant temperature decreases, the reactor coolant flow through the RHR heat exchangers is gradually increased by adjusting the control valve in each heat exchanger outlet line. The normal plant cooldown function of the residual heat removal system is independent of any engineered safety features function.

The normal cooldown return lines are arranged in parallel, redundant flow paths. These lines are also utilized as the low pressure emergency core cooling injection lines to the reactor coolant system. Utilization of the same return lines for emergency core cooling as well as for normal cooldown lends assurance to the proper functioning of these lines for engineered safety features purposes.

Solid Plant Operations

The residual heat removal system is used in conjunction with the chemical and volume control system (see Figure 4.9-2) during cold shutdown operations (less than 200°F) to maintain reactor coolant chemistry and pressure control. Solid plant operations (no bubble in the pressurizer) is one method of operating the plant during the cold shutdown period. This mode of operation is generally limited to system refill and venting operations. The term "solid plant" refers to the fact that the reactor coolant system is completely filled to the top of the pressurizer with coolant.

The RHR system is used to circulate reactor coolant from the loop 4 hot leg to the cold leg connections on each loop. The RHR system is essentially operating as an extension of the reactor coolant system and is completely filled with reactor coolant. Pressure in the system can be changed by either changing the temperature of the reactor coolant or by varying the mass of the reactor coolant within the system. Varying the temperature of the reactor coolant is not an effective method of RCS pressure control due to the time required to heat the coolant and the large pressure changes that accompany small temperature changes. Volume control of the reactor coolant is preferred because of the faster response and because any desired pressure change can be obtained within controllable limits. Since control of the mass in the RCS is the preferred means of pressure control, a portion of the RHR flow is diverted to the chemical and volume control system through valve HCV-128.

The flow diverted to the CVCS is controlled by the position of the backpressure control valve PCV-131, which is located downstream of the letdown heat exchanger. During solid plant operations the flow water returned to the reactor coolant system is determined by the charging rate, which is controlled through manual positioning of charging flow control valve HCV-182. The chemical and volume control system is also a water-solid system with the exception of the volume control tank, which acts as a buffer or surge volume for the purpose of pressure control. Pressure is controlled by maintaining a constant charging rate and varying the flow rate of the water into the chemical and volume control system (via PCV-131). To maintain a constant pressure in the RCS, both flow rates (charging and letdown), must be equal. If the charging rate exceeds the letdown rate, then the pressure in the RCS will increase. Conversely, pressure in the RCS will decrease if the letdown flow rate exceeds the charging flow rate.

Normally, the backpressure regulating valve, PCV-131, is maintained in the automatic mode of operation and set to control the reactor coolant pressure at a desired setpoint. The volume control tank absorbs any mismatches between the charging and letdown flow rates. Pressure regulation is necessary to maintain the pressure in the RCS to a selected range dictated by the fracture prevention criteria requirements of the reactor vessel.

Refueling

Both residual heat removal pumps are utilized during refueling to pump borated water from the refueling water storage tank to the refueling cavity. During this operation, the isolation valves in the inlet line from the reactor coolant system (8701 and 8702) are closed, and the isolation valve from the refueling water storage tank (8812) is opened. The reactor vessel head is lifted slightly, and refueling water is pumped into the reactor vessel through the normal RHR system return lines and then into the refueling cavity through the open reactor vessel. The reactor vessel head is gradually raised as the water level in the refueling cavity rises. After the water level reaches the normal refueling level, the reactor coolant system inlet isolation valves are opened, and the refueling water storage tank supply valve is closed.

During refueling, the residual heat removal system is maintained in service, with the number of pumps and heat exchangers in operation as required by the heat load and technical specification minimum flow requirements.

After completion of refueling, the RHR system is used to return the water from the refueling cavity to the refueling water storage tank via manual valve 8735. The water level is drained to the level of the reactor vessel flange. The remainder of the water in the refueling cavity is removed through drains located in the bottom of the refueling canal.

4.9.2.3 System Summary

The residual heat removal system performs both normal plant functions and accident functions. The normal plant function is the transfer of heat from the reactor coolant system to the component cooling water system during shutdown operations. This operation is referred to as the second phase of plant cooldown, which starts when RCS T_{avg} is at 350°F. The RHR system is designed to remove the decay heat associated with the shutdown reactor until the plant is restarted. During the shutdown, if solid plant operations are desired, the RHR system is used in conjunction with the chemical and volume control system for solid plant pressure control.

The RHR system is normally aligned to perform its accident function. During the injection phase following a loss of coolant accident, water is supplied from the refueling water storage tank to the reactor coolant system cold legs. For long-term cooling and recirculation, the RHR system utilizes the containment sump as a source of water, and the RHR heat exchangers to cool the water prior to returning the water to the reactor coolant system.

The RHR system is also used during refueling to remove decay heat and to transfer water between the refueling water storage tank and the refueling cavity.

4.9.3 Consequences of Loss of RHR

After the fission process is stopped (i.e., the reactor is shutdown) the continuing radioactive decay of fission products and irradiated core materials produces a significant amount of heat. For a typical 3411-MWt nuclear plant, the power associated with this decay heat is about 20 MWt, 24 hours after shutdown from full power. If a means to remove this heat that is being generated in the core is not available, it is obvious that the temperature of the fuel and fuel cladding will increase. Even if the plant is in a cold shutdown condition, the fuel and clad temperature will continue to increase until the point is reached that clad oxidation and fuel melting can occur.

If the plant is in cold shutdown to perform maintenance or refueling, it is very likely that the RCS will be open with steam generator primary manways removed, the pressurizer relief valves open, the pressurizer safety valves and manways removed, or the reactor vessel head vented. When the plant is in mode 5 (cold shutdown), the technical specifications do not require that containment integrity be maintained. The containment equipment hatch and personnel airlocks could be open, and the positions of containment isolation valves could be indeterminate.

Because of the possibilities for system status and alignment during cold shutdown, the time available to replace lost RCS inventory and to re-establish decay heat removal before bulk boiling, core uncovery and fuel damage takes place will vary from plant to plant. The consequences can be severe because of the inability to contain the radioactive fission products that are released once fuel degradation begins.

4.9.4 NRC and Industry Studies

In addition to the studies being performed in conjunction with the resolution of USI A-45, other studies of decay heat removal capabilities have been conducted by independent NRC and industry nuclear safety groups.

A study published by the Nuclear Safety Analysis Center (NSAC) in 1983, "Residual Heat Removal Experience Review and Safety Analysis" (NSAC Report 52), concludes that the "reliability of shutdown decay heat removal could be an important generic safety issue." The study compiled information on over 250 pressurized water reactor (PWR) events involving RHR systems. Over 100 of the events involved an actual loss or significant degradation of decay heat removal capability when it was required to be operable. The results of the events that had specific safety implications fell into three categories: (1) loss of reactor coolant inventory via the RHR system, (2) overpressurization of the RCS, and (3) loss of long-term decay heat removal capability due to RHR system failures.

Even though loss of RCS inventory during cold shutdown conditions might have previously been thought to be unimportant, the analysis by the NSAC concluded that, in certain instances, the loss of inventory combined with the degraded condition of other systems (permitted by technical specifications) needed to replace the lost RCS coolant demonstrated the potential for core uncovery. In one event, if timely operator action had not been taken, core uncovery could have taken place in about 25 minutes (Sequoyah Unit 1, February 11, 1981).

Because of previous repressurization events that have occurred during cold shutdowns at PWRs, the NRC has required that automatic protective systems to prevent cold overpressure be installed. Improper operation and maintenance of these systems can still render them ineffective. Malfunctions or personnel errors during cold shutdown can result in repressurization of the RCS to the setpoint pressure of the pressurizer code safety valves. High pressures could have significant implications regarding reactor vessel brittle fracture limitations.

Many events have taken place that caused the complete loss of the ability to remove decay heat during shutdown. Even though the majority of the events have taken place long enough after shutdown such that sufficient time existed for recovery, the potential exists for decay heat removal losses that could result in bulk boiling conditions in the core. Coolant boiling could create a significant hazard for personnel working in the area as well as lead to core damage.

The NSAC report concludes that significant improvements in decay heat removal capabilities could be made by simply upgrading plant procedures and administrative controls used during plant shutdown. Historically, utilities have emphasized stringent controls and procedural requirements during power operation. The assumption was that during cold shutdown, the plant was in a "safe" condition and that strict controls and safety equipment operability were not necessary. The results of analysis of repetitive events involving decay heat removal systems have demonstrated that this is not necessarily the case.

Some of the recommendations made in the NSAC report include:

1. Improvements in training and procedures related to loss of RCS coolant during RHR system operation (when automatic ECCS is not required to be available by technical specifications), cold overpressure protection, RCS void formation during cold shutdown, long-term unavailability of the RHR system, restoration of air-bound RHR pumps, and inadvertent automatic RHR system isolation;
2. Better administrative controls for maintenance and surveillance during cold shutdown, vessel level monitoring during partially drained operations, critical valve positioning and status control, outage control by operation personnel, and maintenance prioritization; and
3. Minor hardware modifications including better control room indications and alarms for low RHR system flow, actual valve position, valve controls, and shutdown reactor vessel level monitoring systems, and improved instrumentation, data collection and human engineering for shutdown reactor plant operations.

A case study prepared by the NRC office for Analysis and Evaluation of Operational Data (AEOD), "Decay Heat Removal Problems at U.S. Pressurized Water Reactors" (AEOD /C503), was published in December 1985. This study concludes that "for certain postulated events, unless timely corrective actions are taken, core uncovery could result on the order of one to three hours. To date, no serious damage has resulted from the loss-of-DHR [decay heat removal]-system events that have occurred at U.S. PWRs. However, many of the events which have occurred thus far may serve as important precursors to more serious events."

The study's analysis indicates that the underlying or root causes of most of the loss-of-DHR-system events were related to human-factors deficiencies involving procedural inadequacies and personnel error. The majority of the errors were committed during maintenance, testing, and repair activities in shutdown plants. The leading cause of loss of decay heat removal capability was inadvertent automatic closure of the suction isolation valves as a result of human error.

The results of the AEOD analysis show that, in losses of the DHR system occurring during the early stages of shutdown (e.g., within 24 hours after a reactor trip), with the RCS partially drained, or shortly after activation of the DHR system before the primary system is drained, corrective actions must be taken promptly (i.e., within less than two hours unless a loss of RCS inventory is involved) to either restore the DHR system or to implement alternate methods for removing reactor decay heat. This analysis emphasizes the fact that a loss of decay heat removal capability can lead to a safety-significant event unless timely recovery actions are taken.

The AEOD recommendations for improving the reliability of decay heat removal systems include:

1. Improving human factors by upgrading coordination, planning, and administrative control of surveillance, maintenance, and testing operations which are performed during shutdowns;
2. Providing operator aids to assist in determining the time available for DHR recovery and to assist operators in trending parameters during loss-of-DHR events;
3. Upgrading the training and qualification requirements for operations and maintenance staff;
4. Requiring the use of reliable, well-analyzed methods for measuring reactor vessel level during shutdown modes;
5. Modifying plant design to remove automatic closure interlocks and/or power to the DHR suction isolation valves during periods which do not require valve motion; and
6. Clarifying plant technical specifications to eliminate ambiguities associated with operating mode definitions.

4.9.5 Plant Events

4.9.5.1 Diablo Canyon Unit 2 (4/10/87)

On April 10, 1987, Diablo Canyon Unit 2 experienced a loss of decay heat removal capability in both trains. The reactor coolant system had been drained to the midpoint elevation of the hot-leg piping in preparation for the removal of the steam generator manways. During the 85-minute period that the heat removal capability was lost, the reactor coolant temperature increased from 87°F to the boiling point, steam vented from an opening in the reactor vessel head, water spilled from the partially unsealed manways, and the airborne radioactivity levels in the containment rose above the maximum permissible concentration of noble gases allowed by 10CFR20. The reactor, which was undergoing its first refueling, had been shut down for seven days at the time, and the containment equipment hatch had been opened.

Erroneous level indication, inadequate knowledge of pump suction head/flow requirements, incomplete assessment of the behavior of the air/water mixture in the system, and poor coordination between control room operations and containment activities all contributed to the event. Under the conditions that existed, the system that measured the level of coolant in the reactor vessel indicated erroneously high and responded poorly to changes in the coolant level. In addition, the intended coolant level was later determined to be below the level at which air entrainment due to vortexing was predicted to commence. At the time of the event, the plant staff believed that the coolant level was six inches or more above the level that would allow vortexing.

The event began when a test engineer, in preparation for a planned containment penetration local leak rate test, began draining a section of the reactor coolant pump leakoff return line, which he believed to be isolated. However, because of a leaking boundary valve, this action caused the volume control tank fluid to be drained through the intended test section to the reactor coolant drain tank. The control room operators, who were not aware that the engineer had begun conducting the test procedure, increased makeup flow to stop the level reduction inthe volume control tank. A few minutes later, the operators were informed that the reactor coolant drain tank level was increasing, but they could not determine the source of the leakage. Although the actual level of coolant in the reactor vessel was apparently dropping below the minimum intended level, the indication of level in the vessel remained within the desired control band. Subsequently, the electrical current to the operating RHR pump was observed to be fluctuating. The second pump was started, and the running pump was shut down. The current to the second pump also began to fluctuate, so it was immediately shut down as well.

The operators did not immediately raise the water level in the reactor because they still did not know the source of the leakage, the true vessel level, or the status of the work on the steam generator manways. Operators were sent to vent the RHR pumps. One pump was reported to be vented, and a few minutes later an attempt was made to restart the pump. The electrical current to the motor again began to fluctuate, and the pump was secured. During this period the operators did not know the temperature of the coolant in the reactor vessel because the core-exit thermocouples had been disconnected in preparation for the planned refueling. Within an hour, airborne activity levels in the containment were increasing, and personnel began to evacuate from the containment building.

When the operators learned that the steam generator manways had not been removed, action was initiated to raise the reactor vessel water level by adding water from the refueling storage tank. About 10 minutes later, the test engineer identified the source of the leakage and stopped it. When vessel level had been raised sufficiently, one of the RHR pumps was started, and the indicated pump discharge temperature immediately rose to 220°F. At this time the reactor vessel was slightly above atmospheric pressure, and steam was venting from an opening in the reactor vessel head.

Following the loss of decay heat removal capability at Diablo Canyon, the utility took a number of actions to prevent loss of RHR suction during low level operation and to improve recovery should such a loss occur. These actions included the following: (1) evaluation of the reactor vessel level indicating system to determine the level at which vortexing would occur and the effect of vortexing on level measurement; (2) enhancements of instrumentation to provide accurate level measurement, alarm capability, and core-exit temperature measurement during low level operation; (3) enhancement of procedures to include requirements for verifying proper RHR pump suction before starting the second RHR pump; (4) precautions specifying minimum vessel levels as a function of RHR flow; (5) improvements in work planning, control, and communication to include restriction of the work scope to items that do not have the potential to reduce RCS inventory; and (6) improvement of operator training, including a discussion of the potential causes of RHR flow loss, as well as recovery procedures.

Information Notice 87-23 was subsequently issued by the NRC to alert other licensees to the event, and Generic Letter 87-12 was issued to (1) assess safe operation of PWRs when the reactor coolant system water level is below the top of the reactor vessel; (2) determine whether the RHR system meets the licensing basis of the plant, such as GDC 34 and the technical specifications, in this condition; (3) determine whether there is a resultant unanalyzed event that may have an impact on safety; and (4) determine whether any threat to safety that warrants further NRC attention exists in this condition.

4.9.5.2 North Anna Unit 1 (6/27/87)

On June 21, 1987, North Anna Unit 1 operators discovered that approximately 17,000 gallons of reactor coolant had been lost from the RCS while the unit was in cold shutdown. The delay in discovering the inventory loss resulted from the use of pressurizer level as an indication of reactor coolant inventory, failure to use all available indications, and failure to perform a mass inventory balance.

On June 17, 1987, during preparations for a startup following a refueling outage, a problem developed with a reactor coolant pump motor, requiring removal of the motor. When the problem was discovered, the unit was at approximately 195°F and 325 psig, with a bubble in the pressurizer. In order to establish plant conditions for removal of the motor (which may involve leakage from the RCS), the plant would normally have been cooled to less than 140°F and drained to the midpoint level of the hot-leg nozzle, and the residual heat removal system would have been placed in operation. In order to expedite the work, the plant was cooled to 110°F, and the pressurizer was cooled by filling the pressurizer while venting it via the power-operated relief valves (PORVs). The pressurizer level was lowered to 80% with the PORVs open. The PORVs were then shut because the vapor-space temperature led the operators to believe that a bubble still existed, and the level was further lowered to 20%. This evolution was conducted in accordance with a procedure that was not specifically intended for draining the system. The operators did not realize that lowering the level with the PORVs shut and then subsequently cooling the pressurizer would cause a vacuum to form in the pressurizer and cause the level to hold at 20%.

On June 18, 1987, the pump motor was uncoupled, and a small amount of expected leakage (estimated at 2 gpm) up the pump shaft was encountered. This leakage was relatively clean water from the seal injection line past the pump seals, which did not provide a tight seal when the motor was uncoupled. Makeup to the RCS was from the volume control tank (VCT). The VCT level was maintained, with the VCT pressure greater than the RCS pressure. The operators believed that maintaining the pressurizer and VCT levels would maintain the reactor coolant inventory by making up for any losses with flow from the VCT to the RCS. Voids consisting of noncondensible gases and vapor formed in the RCS and collected in the system high points (reactor vessel head and steam generator tubes). The voids were not indicated by any decrease in pressurizer level.

On June 21, 1987, a decision was made to reduce the pump shaft leakage by raising the pressurizer level, cycling the PORVs to vent the pressure, and then lowering the pressurizer level to draw a slight vacuum in the pressurizer. This was a condition that already existed, but the operators were unaware of it. When the PORVs were cycled, the pressurizer relief tank pressure dropped, as well as the pressurizer level, indicating that a vacuum already existed in the pressurizer. The reactor vessel level indicating system (RVLIS) indication at this time was 79%; however, the operators were not monitoring this indication because the system had been modified during the previous outage and the operators thought it would be unreliable. Because of the recorder scale and the time span visible on the RVLIS trend recorder, the change in the level indication would only have been noticed by comparing it with a separate plot or by rolling it back 12 to 24 hours to compare it with the present indication. When the condition was discovered, the operators took action to provide makeup to the RCS and to vent the reactor vessel head, as well as to check other available information to account for the system inventory. A total of 17,000 gallons of borated water was required to reestablish the RCS inventory.

The procedure used to establish plant conditions for removing the RCP motor did not contain appropriate instructions for monitoring and maintaining the RCS inventory. The licensee changed the procedure to require a review of the reactor coolant system inventory and routine surveillance of all available level indications, including that from the RVLIS.

4.9.6 Summary

Requirements for reliable decay heat removal systems were established in the General Design Criteria of Appendix A of 10CFR50 to ensure that core decay heat generated during plant shutdowns could be removed. This capability is necessary to protect the integrity of the fuel and to prevent the offsite release of radioactive fission products. It has become apparent that design deficiencies, improper maintenance, and/or testing and personnel errors have detracted from the reliability of decay heat removal systems and caused additional safety concerns.

The NRC established shutdown decay heat removal requirements as an unresolved safety issue because of the severe consequences which could result from problems that arise when the plant is in the "safe" shutdown condition. NRC and industry studies have analyzed hundreds of events that involved the complete loss of decay heat removal capability for various periods of time. None of the events resulted in core damage or in the significant release of radioactive material, but many were considered precursors of potentially safety-significant events.

Resolution of USI A-45 is not complete, but numerous recommendations have been established by both NRC and industry groups that could significantly improve the availability and reliability of decay heat removal systems at nuclear power plants. Recommended improvements include additional training and procedural requirements for operation while in the shutdown cooling mode, improvements in scheduling and controlling evolutions that could affect the ability to remove decay heat, improvements that give the operator more reliable indication of RCS inventory and RHR system flow, and better guidance for the operator for reestablishing core cooling once it is lost.

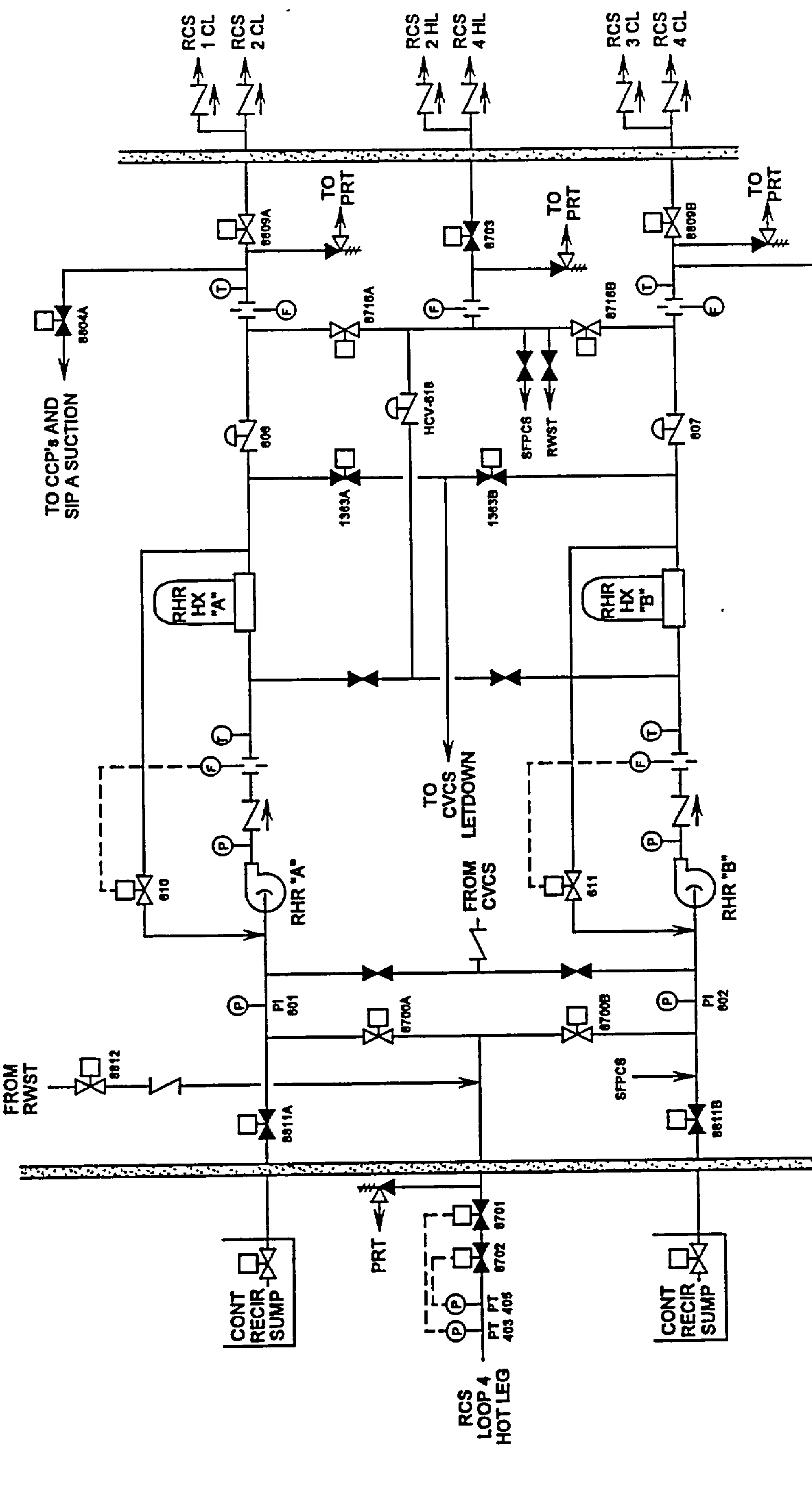


Figure 4.9-1 Residual Heat Removal System

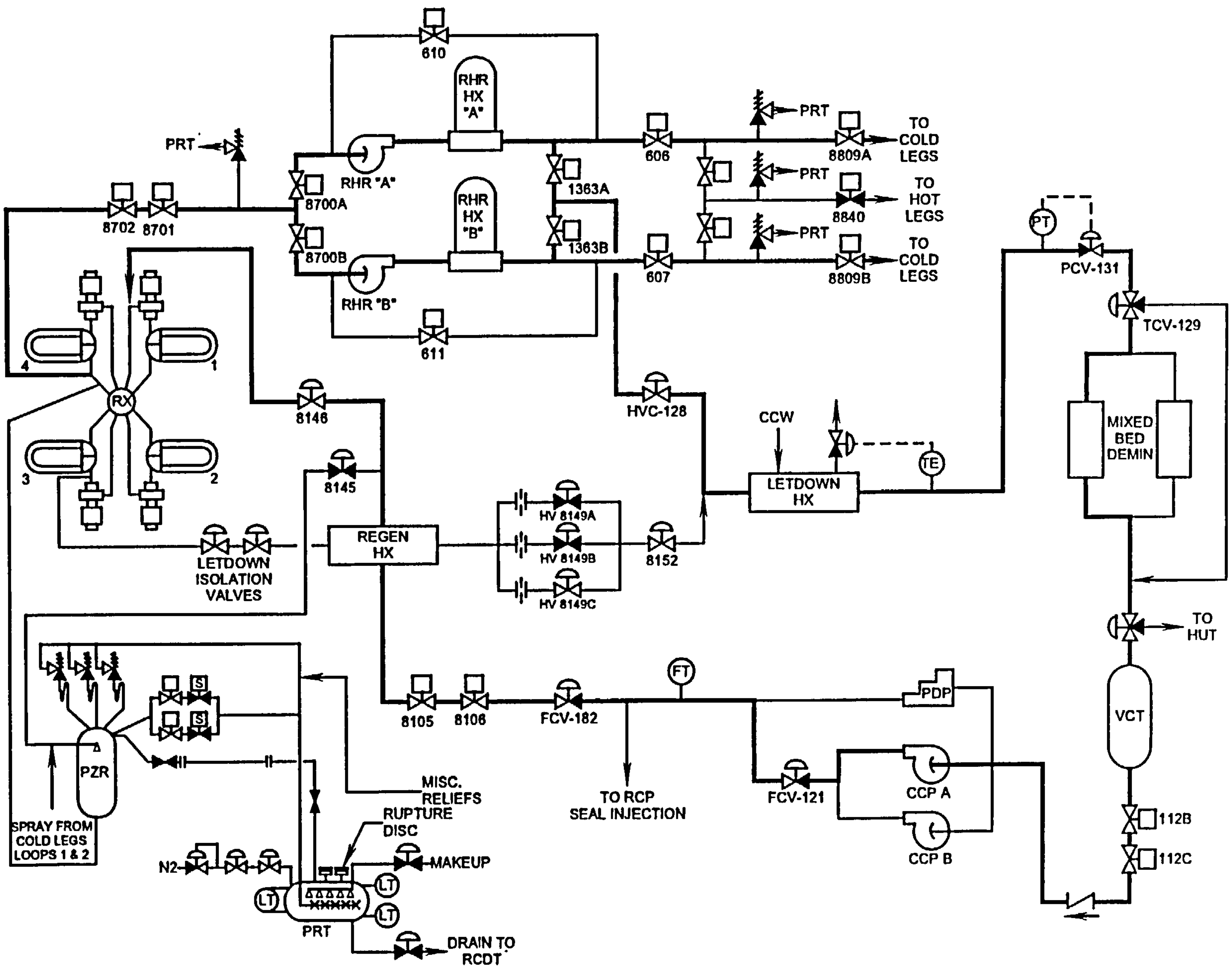


Figure 4.9-2 Solid Plant Pressure Control

0199-3
19-1

Westinghouse Technology Advanced Manual

Section 4.10

Air System Problems

TABLE OF CONTENTS

LIST OF FIGURES

4.10 AIR SYSTEM PROBLEMS

Learning Objectives:

1. List two safety-related functions that rely on plant air systems.

2. List two sources of air system contamination.

3. List two causes (other than contamination) of air system failures.

4.10.1 Introduction

All commercial pressurized water reactors rely on air systems to actuate or control safety-related equipment during normal operation. However, at most pressurized water reactors, the air systems are not classified as safety systems. Plant safety analyses typically assume that non-safety-related air systems become inoperable during transients and accidents, and that the air-operated equipment which is served fails in known, predictable modes. In addition, air-operated equipment which must function during transients or accidents is often provided with backup air (or nitrogen) supplies in the form of safety-grade accumulators so that the equipment can continue to perform its intended functions.

Consider the effects of a loss of all feedwater event. In this scenario, if feedwater or auxiliary feedwater cannot be restored to the steam generators, the operator is directed to start both high pressure injection pumps and open the pressurizer power-operated relief valves (PORVs). This sequence of actions provides a flowpath of emergency core cooling water through the core and out the open relief valves. However, if the PORVs are pneumatically operated and the air system is not functioning correctly, then there can be no core cooling flow until the RCS is pressurized to the safety valve setpoint. This pressure may be so high that the flow from the high pressure injection pumps may not be sufficient to cool the core.

Some units have air-operated main steam isolation valves (MSIVs) that require air pressure to close. These valves must function correctly to ensure that, in the event of a main steam line break, only one steam generator blows down.

In addition to the equipment listed above, instrument air is supplied to many of the containment isolation valves. These valves must operate correctly to ensure the integrity of the containment building in the event of a loss of coolant accident or main steam line break.

The failure of instrument air systems and the effects of the failures on plant operation are discussed in section 4.10.3.

4.10.2 Air System Description

A diagram of a typical air system is shown in Figure 4.10-1. The air system begins with the air compressors, which take a suction from the ambient air and raise its pressure to approximately 100 psig. The compressors then discharge the air to storage receivers. The air system contains two or more 100% capacity compressors that are powered from nonvital 480-Vac electrical busses. The compressors are controlled by pressure switches located on the instrument air receivers. During normal operation, one of the compressors is in service, and the redundant compressor(s) are in standby. The in-service compressor loads (compresses air) when receiver pressure drops below a predetermined value (approximately 95 psig) and unloads (stops compressing air) when receiver pressure increases back to its normal pressure. If the air pressure decreases into the range of 70 - 80 psig (typical), the standby compressor(s) are started.

The discharge of the compressors is routed to the air receivers. The receivers serve as the source of air to pneumatically operated components. From the receivers, the air is routed to the instrument and service air headers. Downstream of the air receivers is the conditioning equipment. This equipment consists of the instrument air dryers and the instrument air filters. The dryers serve to remove moisture from the air supply while the filters are installed to remove foreign particles from the air stream. These two components are necessary because the materials and the small clearances of the internal moving parts of pneumatic equipment require clean, dry, and oil-free air for reliable, trouble-free operation. From the conditioning equipment the air is supplied to the air distribution headers.

Figure 4.10-1 lists several components that are supplied from the instrument air system. The equipment can be subdivided by its building location: turbine building, auxiliary building, and containment building. The instrument air system in the turbine building supplies loads such as the turbine bypass valves, the feedwater control valves, and the feedwater heater extraction and level control valves. The auxiliary building air loads are items such as decay heat removal cooler control valves, the main steam isolation valves, and letdown control valves. The containment air supply provides air for the pressurizer power-operated relief valves and spray valves. The instrument air supply to the containment building is equipped with automatic isolation valves which close on a containment isolation signal. When the isolation occurs, the air supply to the equipment inside the containment is lost.

The service air supply shown in Figure 4.10-1 is used to supply air to hose stations that, in turn, supply air to pneumatic tools, tank spargers, etc. Some of the pressurized water reactors have a separate air system which supplies the service air requirements.

4.10.3 Air System Problem Areas

4.10.3.1 Air System Contamination

Moisture

Although the instrument air dryers are designed to remove water from the air system, moisture is one of the most frequently observed contaminants in air systems. Water droplets entrained in the air can initiate the formation of rust or other oxide particles.

Water droplets can cause the malfunction of electrical-to-pneumatic converters by blocking internal passageways, or by forming corrosion products which block internal passageways or cause sticking or binding of moving parts. In addition, water droplets can obstruct the discharge ports on solenoid air pilot valves, degrading their ability to function properly. Furthermore, moisture can cause corrosion of air system internal surfaces, as well as the internal surfaces of equipment connected to the air system (e.g., valve bodies). Rust and other oxides have been observed to cause the exit orifices of air pilot valves and other (air-operated) equipment to be partially or totally blocked, resulting in degraded equipment operation or complete loss of function. Additionally, rust particles on the inside of the piping or connected equipment have the potential to be dislodged during severe vibrations (e.g., due to earthquake or water hammer), which could lead to common-mode equipment failures.

Particulates

Particulate matter has been found to have degraded or prevented air from venting through the discharge orifices of solenoid air pilot valves and valve air operators. A clogged orifice changes the bleeddown rate, which affects the valve opening or closing times and can result in stuck valves. Additionally, small particles have prevented electrical-to-pneumatic converters from functioning properly (i.e., from opening or closing on demand). Air dryer desiccant has been found to damage solenoid air pilot valve seals, preventing air-operated valves from functioning correctly.

Hydrocarbons

Hydrocarbon contamination of air systems can cause sluggish valve operations, as well as a complete loss of valve motion. Compressor oil has been observed to leave gum-like residues on valve internal components. This residue causes the valves to operate sluggishly or erratically or even to stick completely. Hydrocarbons have also been found to have caused valve seals to become brittle and to stick to mating surfaces, thereby preventing valve motion. In some cases, the seals were found to have torn apart or to have flaked off, resulting in loose particles which blocked air discharge orifices.

4.10.3.2 Air System Component Failures

Air Compressors

Instrument air systems include redundant compressors, but generally they are not designed as safety-grade components. As a result, a single failure in the electrical power system or the compressor cooling water supply can result in the loss of all air compressors. Because plants have redundant air compressors and automatic switching features, single random compressor failures usually do not result in total air system failures. Most air system compressors are of the oilless type. However, some plants with oil-lubricated compressors have experienced oil contamination of their air systems. Similarly, the temporary use of oil-type compressors as backup or emergency compressors (e.g., skid-mounted, diesel-operated compressors) without adequate filtration and drying can result in significant air system degradation.

Distribution Systems

Since an instrument air system is not generally designated as safety-grade or safety-related, it is vulnerable to a single distribution system failure. For example, a single branch line or distribution header break can cause depressurization in part, and possibly all, of an air system.

Dryers and Filters

Single failures in the instrument air filtration or drying equipment can cause widespread air system contamination, resulting in common-mode failures of safety-related equipment. For example, a single failure such as a plugged or broken air filter, a malfunctioning desiccant tower heater timer, or plugged refrigerant dryer drain can cause desiccant, dirt, or water to enter the air lines. As discussed above, such contaminants can result in significant degradation, or even failure, of important air system components.

4.10.4 Air System Problems

The following sections deal with actual plant problems caused by air system failures.

4.10.4.1 Air System Contamination

During surveillance testing conducted from July 21 to July 26, 1985, Turkey Point Units 3 and 4 experienced recurrent failures of the auxiliary feedwater (AFW) system due to instrument air contamination. The recurrent problems involved simultaneous failures of the AFW flow control and main feedwater bypass valves. During the events, the electrical-to-pneumatic converters and pneumatic valve positioners experienced common-mode failures. The three turbine-driven AFW pumps (which serve both Turkey Point units) experienced overspeed trips, which were complicated by the sticking of multiple flow control valves and sluggish main feedwater bypass valves.

The plant operations staff had been aware of an instrument air system water accumulation problem for some period of time. However, the operations staff was unaware of the potential problems which might be caused by the water. Accordingly, the operations and maintenance staff initially attempted to correct the AFW control valve problem, as they had previously, by blowing down the air regulators. The procedure was not successful in restoring the functional reliability of the valves. When it became aware of the problem, the licensee's engineering staff hypothesized that corrosion products inside the instrument air system may have been a source of the gross degradation. With the subsequent realization that contaminated instrument air might be the root cause of the recurrent AFW system problems, the licensee requested the architect engineer to evaluate the effect of contaminants in the air supply on the safety-related and non-safety-related equipment. The architect engineer also was requested to determine the maximum particulate size that the safety-related instrument air system equipment could accommodate without adverse effects and the effects of particulates on the instrument air system. The architect engineer's analysis determined that many safety-related devices could be adversely affected by particulates in the instrument air system. Some of the safety-related systems which could be affected are: (1) the secondary system (steam dump to atmosphere), (2) the charging system, (3) the residual heat removal system, and (4) the AFW system.

As indicated above, the Turkey Point AFW systems for both units were vulnerable to instrument air system contamination. In addition, the non-safety-related main feedwater bypass valves have experienced simultaneous common-mode failure (stuck closed) as a result of water in the instrument air system. This failure is potentially significant because the bypass valves are used to control the non-safety-related backup AFW flow provided by the two motor-driven startup pumps. Failure of the main feedwater bypass valves could result in the loss of diverse AFW capability.

4.10.4.2 Instrument Air System Isolation

There have been many events at Westinghouse plants in which the loss of instrument air resulted in a low temperature overpressurization of the RCS. Typically, in these events the loss of instrument air resulted in closure of the letdown isolation valves, the opening of valves in the charging line, and an increase in the charging pump speed (and thus an increase in charging flow). One such event occurred at Farley Unit 2 on October 15, 1983.

The plant was solid in preparation for a startup. An operator inadvertently isolated the instrument air system. As a result, while the charging pump was operating, the letdown line isolated per design and the throttle valve (flow control valve) in the charging line opened to its full-open position. The RCS pressure increased to the point that pressure was relieved through one residual heat removal pump suction line relief valve. The other residual heat removal train relief valve was unavailable. The RCS pressure rose to 700 psig, which was in excess of the final safety analysis report's calculated value for a low temperature overpressure event.

4.10.4.3 Loss of Air Compressors

During startup testing on March 14, 1985, Byron Unit 1 was intentionally tripped from 12% power as part of a loss of offsite power test. With the loss of ac power, the station air compressor tripped, resulting in a gradual depressurization of the air system. During the transient, a low steam line pressure signal occurred, and two of the four main steam isolation valves closed. One MSIV remained fully open, and the other closed only partially. Attempts to manually close the two valves were unsuccessful. Operators eventually were able to close the valves with the assistance of air-powered hydraulic pumps after plant air pressure was restored.

Each MSIV is provided with an accumulator isolated from the MSIV by two check valves. The purpose of the check valves is to allow accumulator air to provide motive power to the MSIV in the event of a loss of the instrument air system. Subsequent bench testing of spare valves and in-situ testing of valves which were installed in the plant revealed that 11 out of 19 air check valves associated with the MSIV accumulators would not close tightly on a gradual loss of pressure. However, testing showed that the valves would close properly for a rapid loss of instrument air pressure.

4.10.4.4 Instrument Air Header Maintenance

On May 15, 1981, while Arkansas Nuclear One Unit 2 was in mode 6 and core alterations were in progress, the instrument air system was temporarily isolated so that modifications could be made to the system. When the air system was isolated, the pressure in the spent fuel pool/refueling canal gate air seal began to drop. The drop in pressure resulted in the loss of seal integrity, and a leak path was established between the fuel pool and the containment building. The spent fuel pool water level dropped approximately five feet in a period of 40 minutes. The minimum level reached was 21 feet, which is about 2 feet less than the minimum level allowed by plant technical specifications. To terminate the event, the instrument air system was unisolated, restoring the pneumatic seal integrity. Borated water was also added to the spent fuel pool to restore level. One week after the drain-down event, the licensee completed an analysis of a postulated loss of instrument air to the spent fuel pool gate seal. The analysis concluded that a longer duration loss of instrument air could have resulted in a fuel pool drain-down to a level near the top of the upper end fittings of the spent fuel assemblies.

4.10.5 Summary

As illustrated by the plant events, losses of instrument air do occur. Failures of associated equipment and systems are usually not predicted in plant safety analyses. Consequently, some plants with significant instrument air system degradation may be operating or may have operated with much higher risk than previously estimated. Because many plants do not have specific license requirements prohibiting operation with degraded air systems, high confidence does not exist that all plants will voluntarily take corrective action to avoid plant operation with degraded air systems in the absence of a serious event.

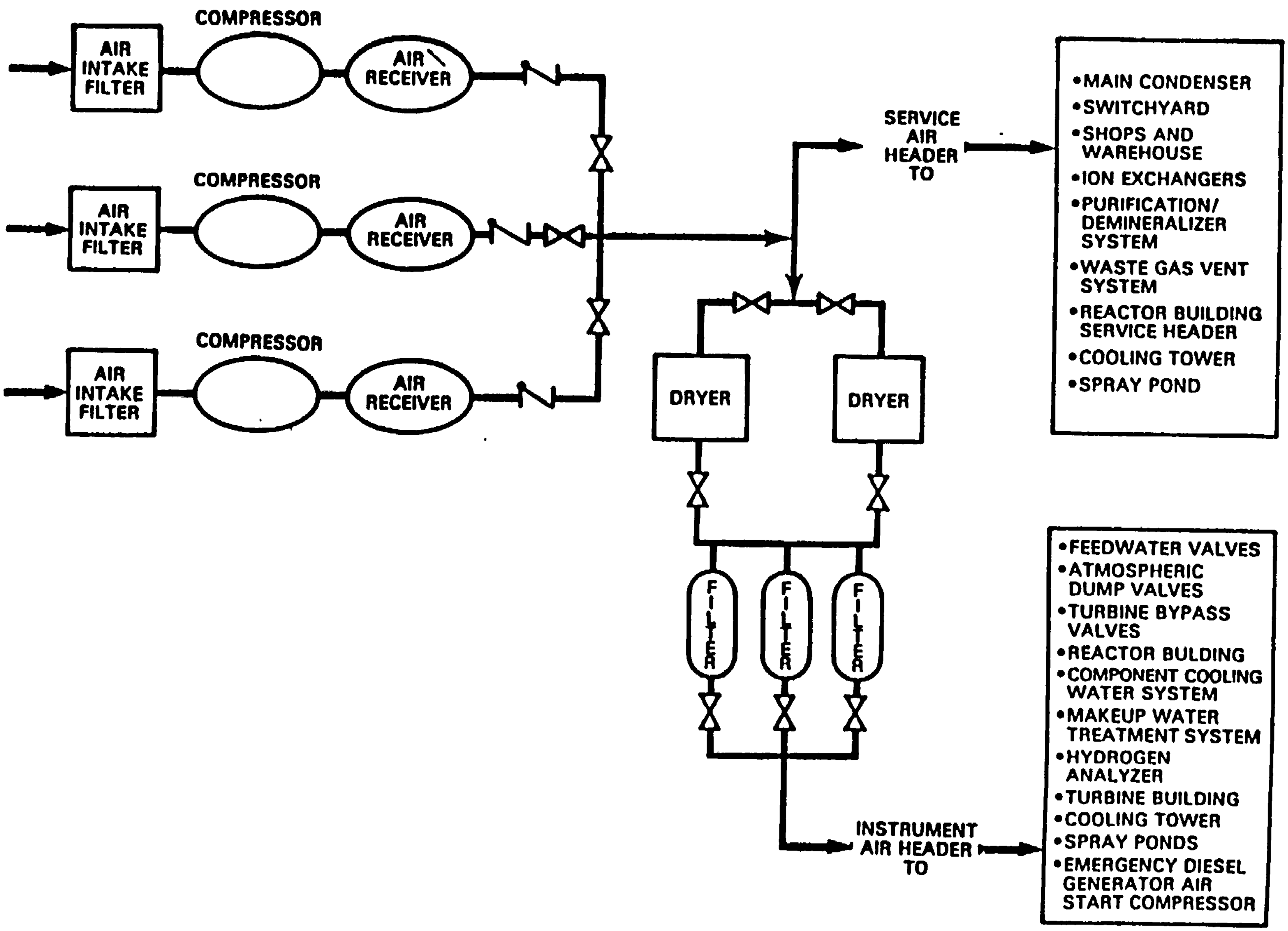


Figure 4.10-1 Typical Air System