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Diagnosis of Condensation-Induced Waterhammer

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Case Studies

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ABSTRACT

This guidebook provides reference material and diagnostic procedures concerning condensation–induced waterhammer in nuclear power plants. Condensation–induced waterhammer is the most damaging form of waterhammer and its diagnosis is complicated by the complex nature of the underlying phenomena. In Volume 1, the guidebook groups condensation–induced waterhammers into five event classes which are have similar phenomena and levels of damage. Diagnostic guidelines focus on locating the event center where condensation and slug acceleration take place. Diagnosis is described in three stages: an initial assessment, detailed evaluation and final confirmation. Graphical scoping analyses are provided to evaluate whether an event from one of the event classes could have occurred at the event center. Examples are provided for each type of waterhammer. Special instructions are provided for walking down damaged piping and evaluating damage due to waterhammer. To illustrate the diagnostic methods and document past experience, six case studies have been compiled in Volume 2. These case studies, based on actual condensation–induced waterhammer events at nuclear plants, present detailed data and work through the event diagnosis using the tools introduced in the first volume.

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CASE STUDIES IN CONDENSATION–INDUCED WATERHAMMER

Waterhammer diagnosis requires careful attention to the details of plant system design and operation. It is not practical to include in this guidebook all the relevant design and operational information necessary for diagnosis of waterhammer in general. Therefore, details are included by way of specific examples, or case studies.

This Volume contains six case studies of condensation–induced waterhammer diagnosis. These case studies have several purposes, which are to:

1. illustrate elements of event diagnosis which are too detailed to be contained in the general procedure of Chapter 3 of Volume 1,
2. show the type of information which can be obtained in an actual diagnosis,
3. illustrate a variety of systems and phenomena,
4. show the key evidence leading to a particular diagnosis.

The case studies are all either based on actual waterhammer events or are composites of several actual events. The scope of each case is limited by the available factual information. None of these case studies is able to illustrate a complete and "ideal" diagnosis such as outlined in Volume 1. Indeed, such a comprehensive diagnosis is appropriate only for most severe and least common events. Each case in this Volume highlights a few particular aspects of waterhammer diagnosis, which are listed at the beginning of each chapter.

Many diagnoses are performed by teams of engineers, and it is not possible to break down the diagnostic process into the steps outlined in Chapter 3 of Volume 1. Desired information and data are often not available. Often a plant can quickly be returned to service with conservative operational or design modifications which limit operation in some way. That is, the time and resources required for a true confirmation are judged to be excessive. As a result, the diagnoses of some waterhammer events are never fully confirmed and the true cause may not be fully resolved. In such cases the continued avoidance of another similar waterhammer is the best practical confirmation which is achieved.

1 A SUBCOOLED WATER SLUG EVENT IN A PWR STEAM GENERATOR

This case concerns a severe waterhammer which occurred in the feedwater system of a pressurized water reactor. Damage was great (fracture of an 18" main feedwater pipe) and extensive confirmatory tests were performed, both at laboratory scale and in situ.

1.1 PURPOSE OF THIS CASE

This case is presented to:

1. illustrate a subcooled water slug event with very severe damage,

2. show how operational data can assist in diagnosis,

3. illustrate extensive use of confirmatory tests, both scale model and in situ,

4. introduce the feedwater system for a pressurized water reactor in which several waterhammer events have occurred.

1.2 SYSTEM DESCRIPTION

This event involves the feedwater system, auxiliary feedwater system and the steam generator of a pressurized water reactor.

MAIN FEEDWATER SYSTEM

The purpose of the feedwater system is to provide high pressure feedwater to cool the steam generators. A schematic diagram of the major components of the main feedwater (MFW) system is illustrated in Figure 1.1. The system consists of two MFW pumps, ten feedwater heaters, and piping and valves to control the flow of feedwater to the three steam generators.

The MFW pumps are each one–half capacity two–stage centrifugal pumps with sufficient capacity to deliver the required amount of feedwater to all three steam generators during normal operation. Each feedwater pump discharges through a check valve (FWS 438 and 439) through the first point high pressure heater to a common header. The header splits the flow into three feedlines to the three steam generators. The feedlines include valves FCV–456, 457 and 458 for flow control and check valves FWS–345, 346 and 398 to prevent backflow. Each feedline has a bypass system for use in low flow conditions such as startup or shutdown operations. Auxiliary feedwater can be provided to the steam generators via the MFW piping downstream of the flow control stations.

The layout of feedwater pipe #2 is shown in isometric projection in Figure 1.2. After the containment penetration there is a long horizontal run at el. 58'–9", followed by gradual rise up to el. 96'. About 17 feet from steam generator #2 there is a vertical rise to el. 104'–9", which is the level of the feedwater nozzle. Figure 1.3 illustrates the final horizontal pipe run to the steam generator (Figure 1.3 also shows how the feedline was modified following the waterhammer).

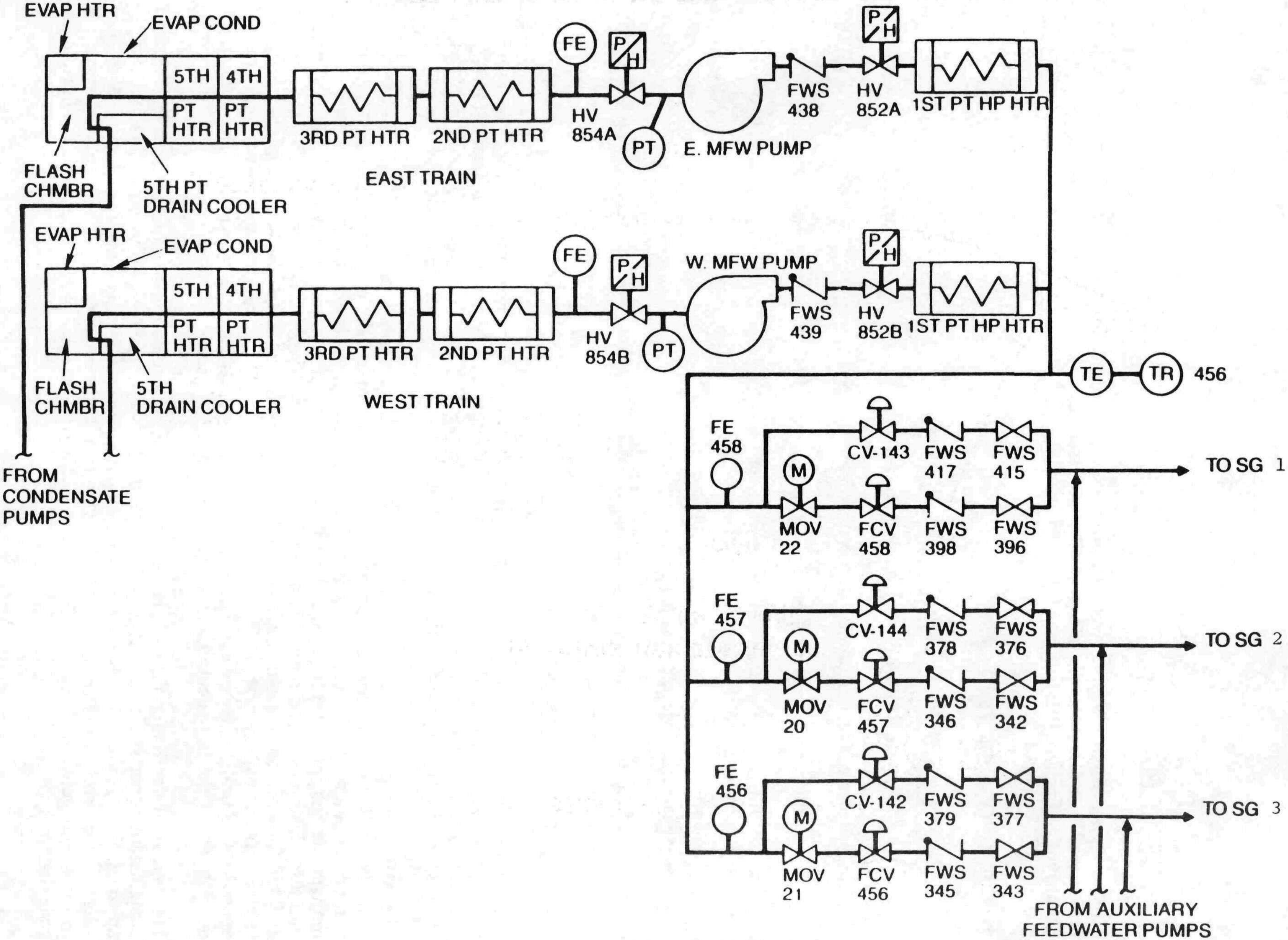


Figure 1.1 MAIN FEEDWATER SYSTEM

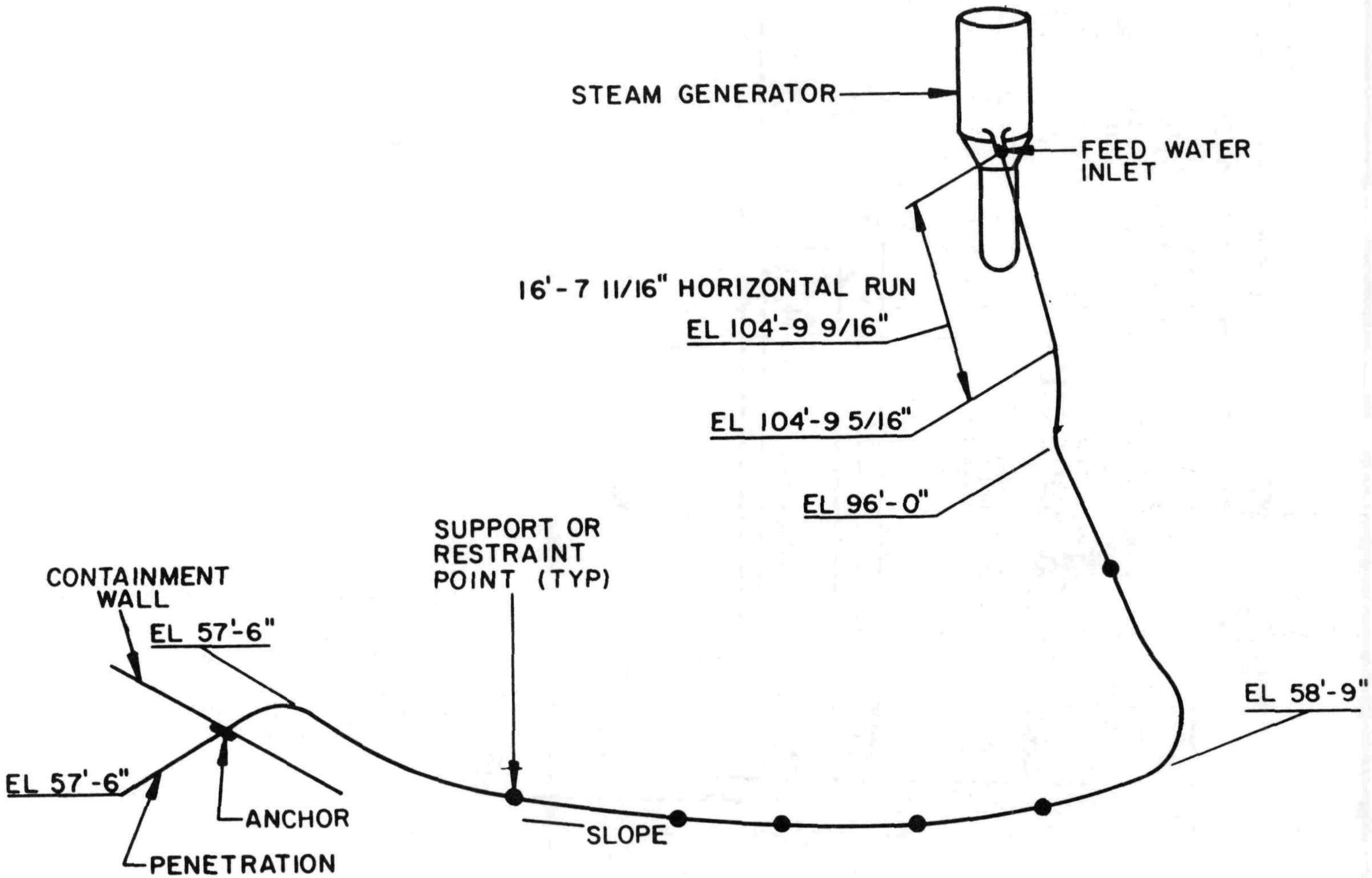


Figure 1.2 FEEDWATER PIPING INSIDE CONTAINMENT FOR STEAM GENERATOR #2

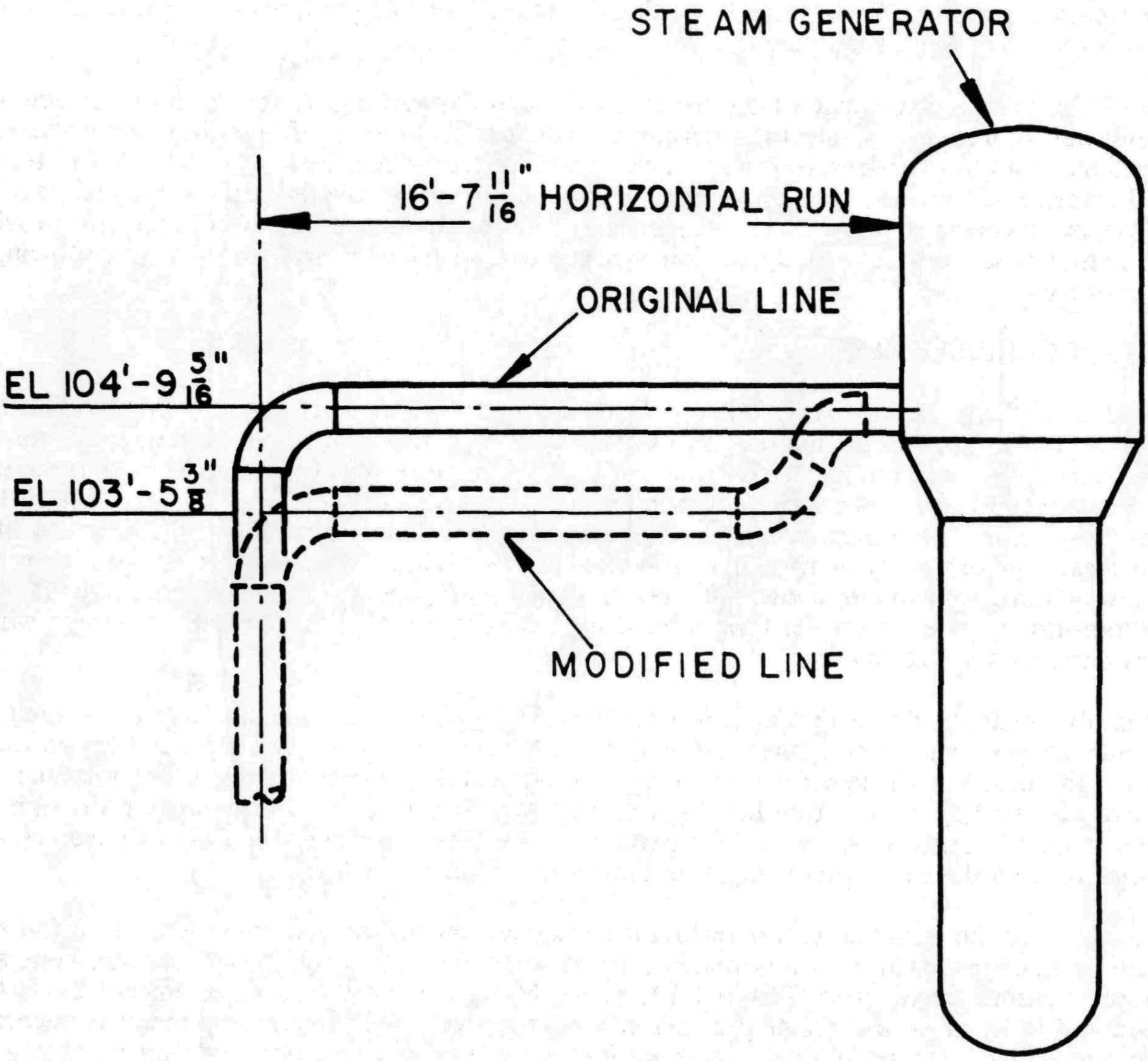


Figure 1.3 FEEDWATER PIPING TO STEAM GENERATOR #2

AUXILIARY FEEDWATER SYSTEM

A simple schematic of the auxiliary feedwater (AFW) system appears in Figure 1.4. Two AFW pumps, one turbine driven and the other motor driven, supply emergency feedwater to the steam generators. Each pump has a design capacity of 420 gpm, and is intended to be run at half–capacity when supplying the steam generators.

The AFW pumps take suction from the auxiliary feedwater storage tank and discharge into the feedwater header to the steam generators. Additional sources of auxiliary feedwater are available from the condensate storage tank and the service water reservoir. The AFW storage tank, when full, contains enough water (240,000 gallons) to remove all reactor residual heat for 55 hours following shutdown. The condensate storage tank and service water reservoir provide additional heat removal capacity sufficient to remove all residual heat for 34 days following a reactor trip.

STEAM GENERATOR

Three steam generators extract energy from the primary (reactor) coolant and provide this energy in the form of high pressure saturated steam suitable to drive a power turbine for electrical power generation. To accomplish this, the main feedwater is pumped into the steam generators and boiled. A cutaway drawing of a U–tube steam generator is given in Figure 1.5. Feedwater enters the steam generators through a main feedwater pipe and is distributed within the steam generator by a ring sparger called a "feedring." This system is visible in the cutaway drawings and is shown in greater detail in Figure 1.6. This Figure illustrates a bottom–draining feedring, the type which was actually used in the feedwater system which was damaged by waterhammer.

From the feedring, the feedwater is distributed into the downcomer annulus formed by the tube bundle wrapper and steam generator shell. The feedwater mixes with recirculation flow and enters the tube bundle near the tubesheet. Boiling occurs as the fluid rises in the tube bundle. Energy for boiling comes from hot, high pressure primary reactor coolant flowing through the tube bundle. Centrifugal moisture separators and positive entrainment steam dryers remove moisture from the steam producing a minimum exit quality of 99.75%.

The range of the principal steam generator parameters during normal operation are as follows: Gross output ranges from a few hundred up to approximately 1,000 MWe. Steam generator vessel pressure ranges from 700 to 1,100 psia. Main feedwater flow rate ranges from a few thousand to as much as 16,000 gpm per steam generator. Feedwater temperature is generally close to 450°F. During normal operation, the liquid level is controlled within a narrow range of several feet. The feedring is located beneath the normal liquid level.

1.3 SEQUENCE OF EVENTS LEADING TO WATERHAMMER

During startup of Unit 2, a 900 MWe pressurized water reactor, the turbine tripped due to high water level in steam generator #2. At the time of the trip, the plant was at 7% rated power and was being prepared for synchronization of the generator to the system. Normal feedwater flow was interrupted because of the turbine trip, and the steam generators were supplied by auxiliary feedwater. The level in steam generator #1 dropped, and the reactor tripped due to low–low steam generator water level.

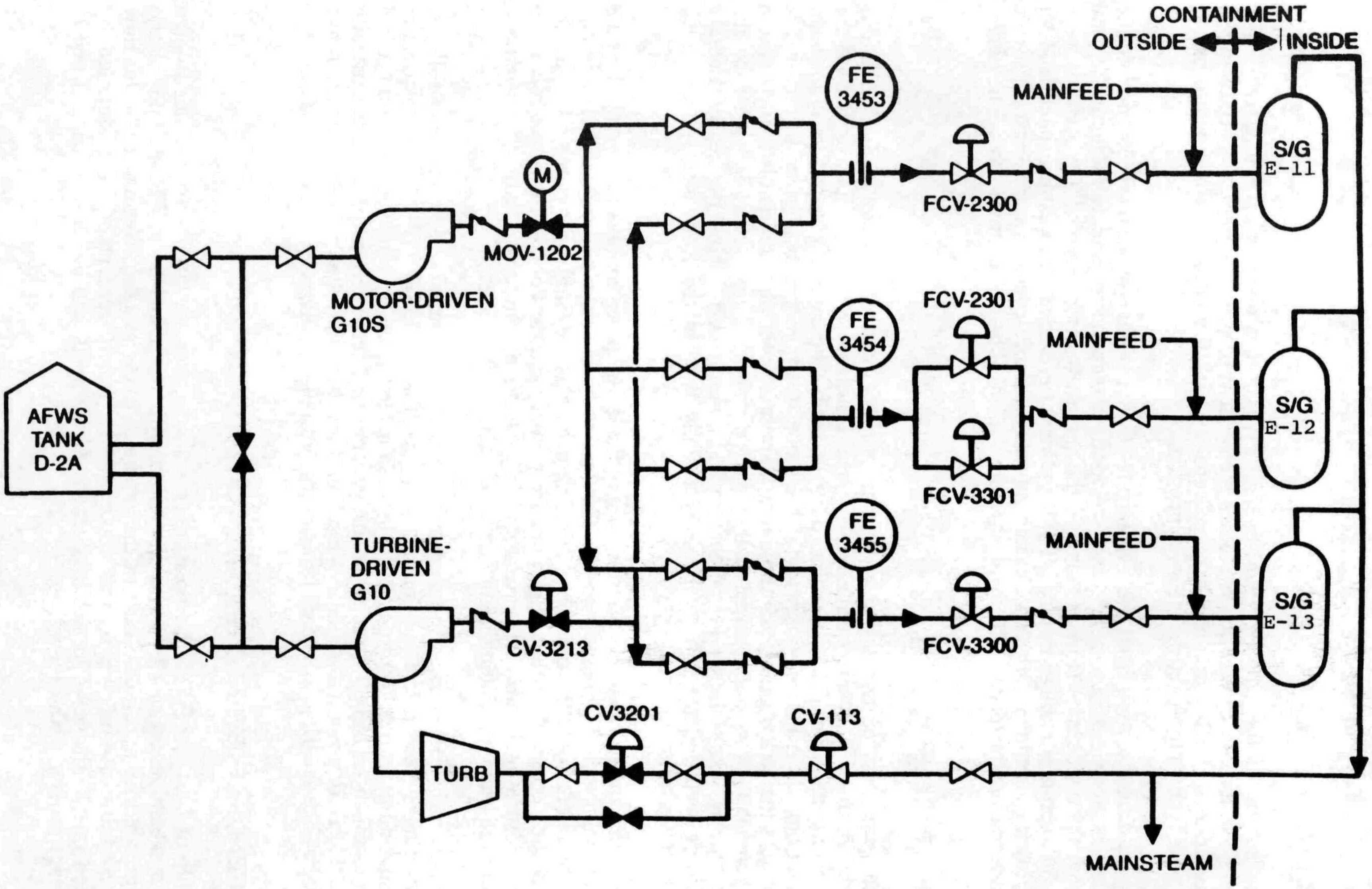


Figure 1.4 AUXILIARY FEEDWATER SYSTEM

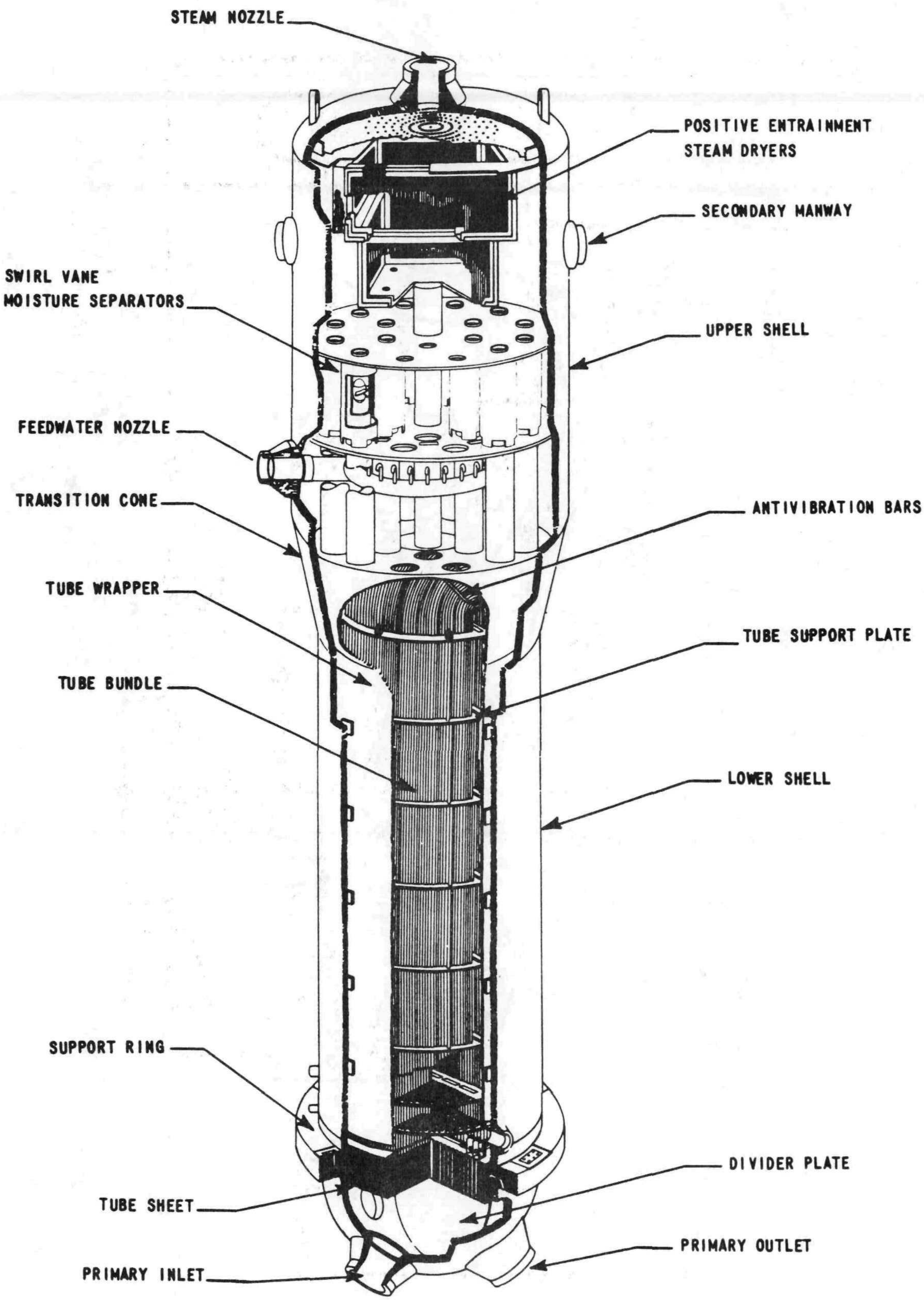


Figure 1.5 CUTAWAY OF STEAM GENERATOR

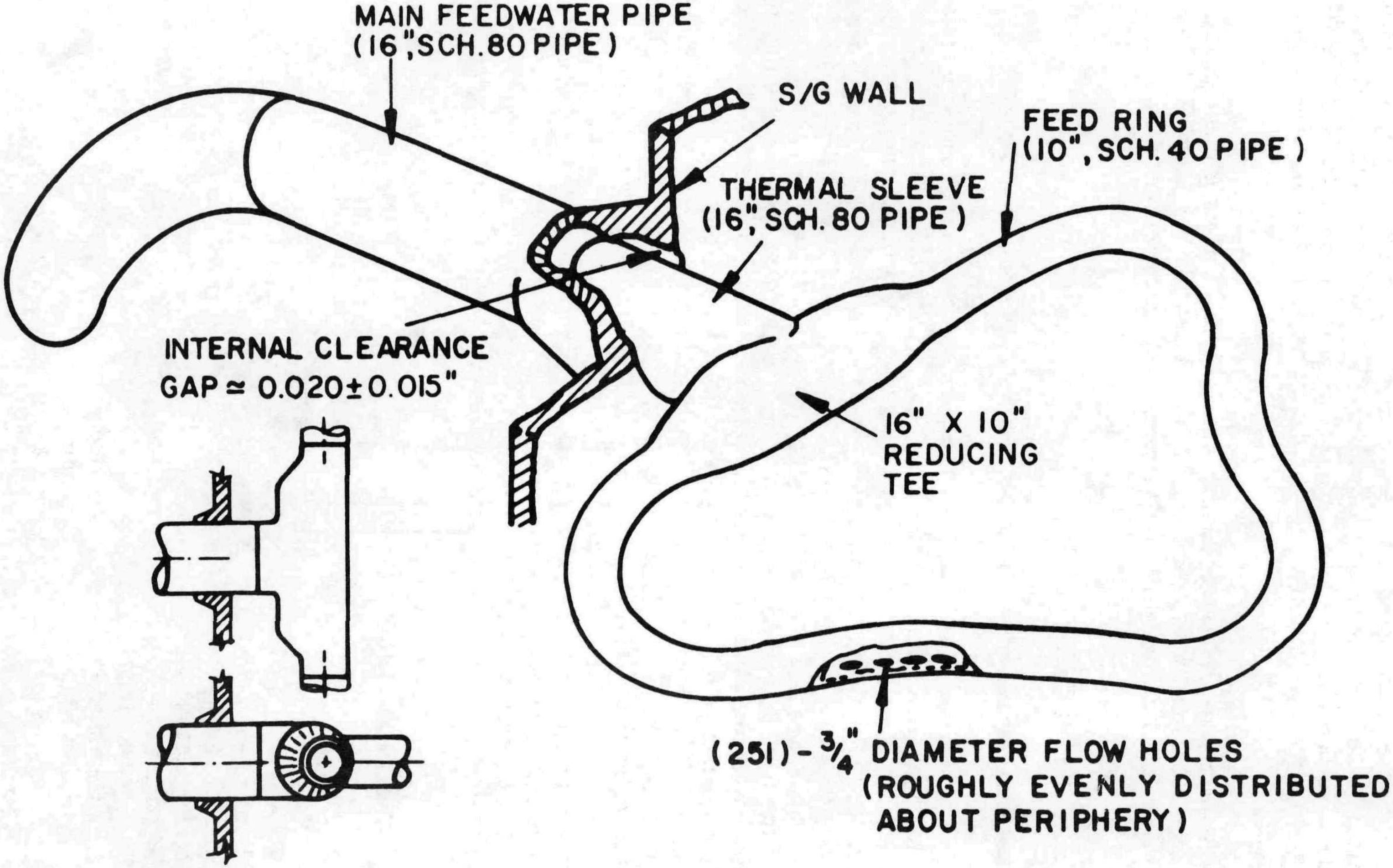


Figure 1.6 SKETCH OF STEAM GENERATOR FEEDRING

At about the time of the reactor trip, a technician stationed outside containment heard a loud noise and observed that the 18" feedwater line to steam generator #2 was shaking. Following the reactor trip, the water level in steam generator #2 continued to fall. Twice more, loud noises were reported and the same feedwater line was observed to shake. Containment temperature and humidity began to rise. Operators determined that the level in steam generator #2 could not be restored, and the plant was cooled down. The steam generator was then isolated

A detailed sequence of events is presented in Table 1.1. During plant cooldown, the steam generator feedwater lines were inspected. It was found that the main feedwater line to steam generator #2 had a 180° circumferential crack at the penetration just inside containment.

1.4 DESCRIPTION OF DAMAGE

Major damage was found to the feedwater line and the containment penetration.

The 18" feedwater line failed with a fracture near the containment penetration sleeve, as illustrated in Figure 1.7. The fracture extended approximately 180° around the pipe. In the horizontal section of feedwater line #2 within a few feet of the steam generator feedwater pipe nozzle, localized radial bulging was noted. Figure 1.8 shows the extent of this deformation. The other two feedwater lines were inspected and found to be within acceptable tolerances.

Sections of the containment liner above the feedwater pipe penetrations showed slight inward bulging away from the containment wall. Intermittent bulging of the liner occurred over an arc of approximately 60 feet. Maximum deviation from the as–built condition was approximately 1.25". Apparently, the liner was pulled away from a number of anchor studs that are embedded in the concrete containment walls and attached to the liner. Ultrasonic inspection revealed that 9 of the 28 studs in the are bulged area were broken.

The alignment of the #2 feedwater pipe was inspected using survey equipment. Movement had occurred with a small permanent deformation, indicated by 3/4" clearance at the elbow restraint near the penetration (prior clearance was nominally zero). Some piping restraints and snubbers, both inside and outside containment, showed evidence of displacement.

1.5 WATERHAMMER DIAGNOSIS

EVENT CENTER

Locating the event center is explained using Figure 1.2. The major damage locations are the feedpipe deformation near the #2 steam generator and the crack near the containment inner wall. Pipe cracks are caused by segment forces, while radial bulging is due directly to severe overpresure, suggesting a point of impact. This sort of plastic deformation can significantly reduce the strength of a waterhammer pressure wave. Thus:

- maximum overpressure occurred in the horizontal pipe section near the steam generator, and
- a large–magnitude pressure wave travelled through the feedpipe inside containment, resulting in the pipe crack.

Table 1.1 Sequence of Events	
Time (approximate)	Event
Prior to Incident	Reactor critical, about 7% power T_{avg} = 548°F Turbine is at 1750 rpm
7:38 a.m.	Turbine trip due to high level on No. 3 Steam Generator
	In service No. 21 main boiler feed pump shutdown – 2 motor-driven auxiliary boiler feed pumps start and restore level in all but Steam Generator No. 2
7:45 a.m.	Reactor trip due to low-low level in No. 1 Steam Generator
	First shaking accompanied by a loud noise in No. 2 feedwater line observed
7:50 a.m.	Primary system stabilized at T_{avg} = 533°F Pressure in steam generators = 890 psig
	Level in No. 2 Steam Generator still dropping
8:00 – 8:30 a.m.	Evidence of moisture in containment
8:30 a.m.	Second shaking accompanied by a loud noise was observed in No. 2 feedwater line
9:10 a.m.	Level in waste holdup tank increases, indicating rising sump level.
9:15 a.m.	Containment temperature increases to a maximum of 110°F. Remaining two of five fan cooler units started.
	Containment humidity recorder indicates increased humidity to a wet bulb temperature of 90°F.
	Containment recirculation fan cooler units condensate collection system weirs indicate rising level.
	Isolation valves to and from No. 2 Steam Generator are shut.
9:40 a.m.	Steam-driven auxiliary feed pump started. Additonal shaking and noise was observed on the No. 2 feedwater line.
	Secured feed to No. 2 Steam Generator
10:10 a.m.	Cooldown commenced to bring plant to a cold shutdown condition.
10:15 a.m.	Containment entry made and possible break was identified.
10:45 a.m.	Safety injection initiated due to high differential steam generator pressure.
	Steam generator went dry.
11:05 a.m.	No. 2 Steam Generator was completely isolated by shutting the manual stop valves in the auxiliary feedwater water and chemical feed lines.
	Reactor Coolant Temperature – 450°F.

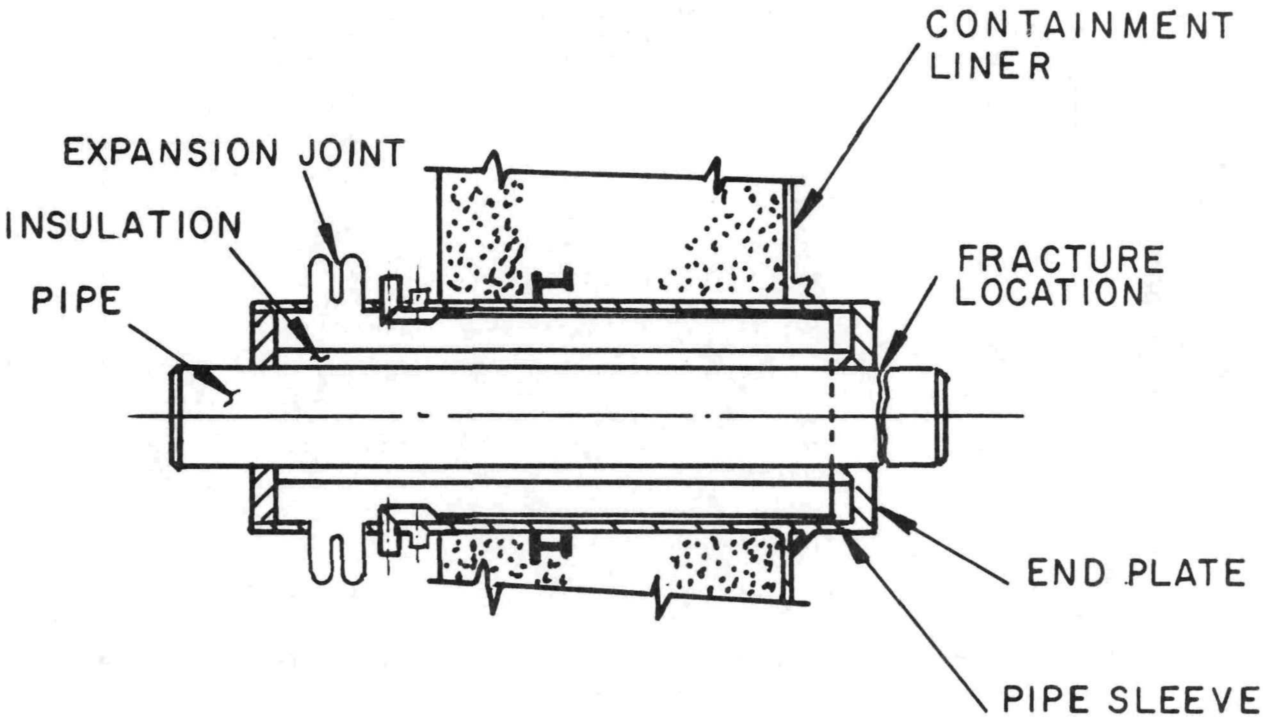


Figure 1.7 FEEDWATER PIPE FRACTURE NEAR THE CONTAINMENT PENETRATION

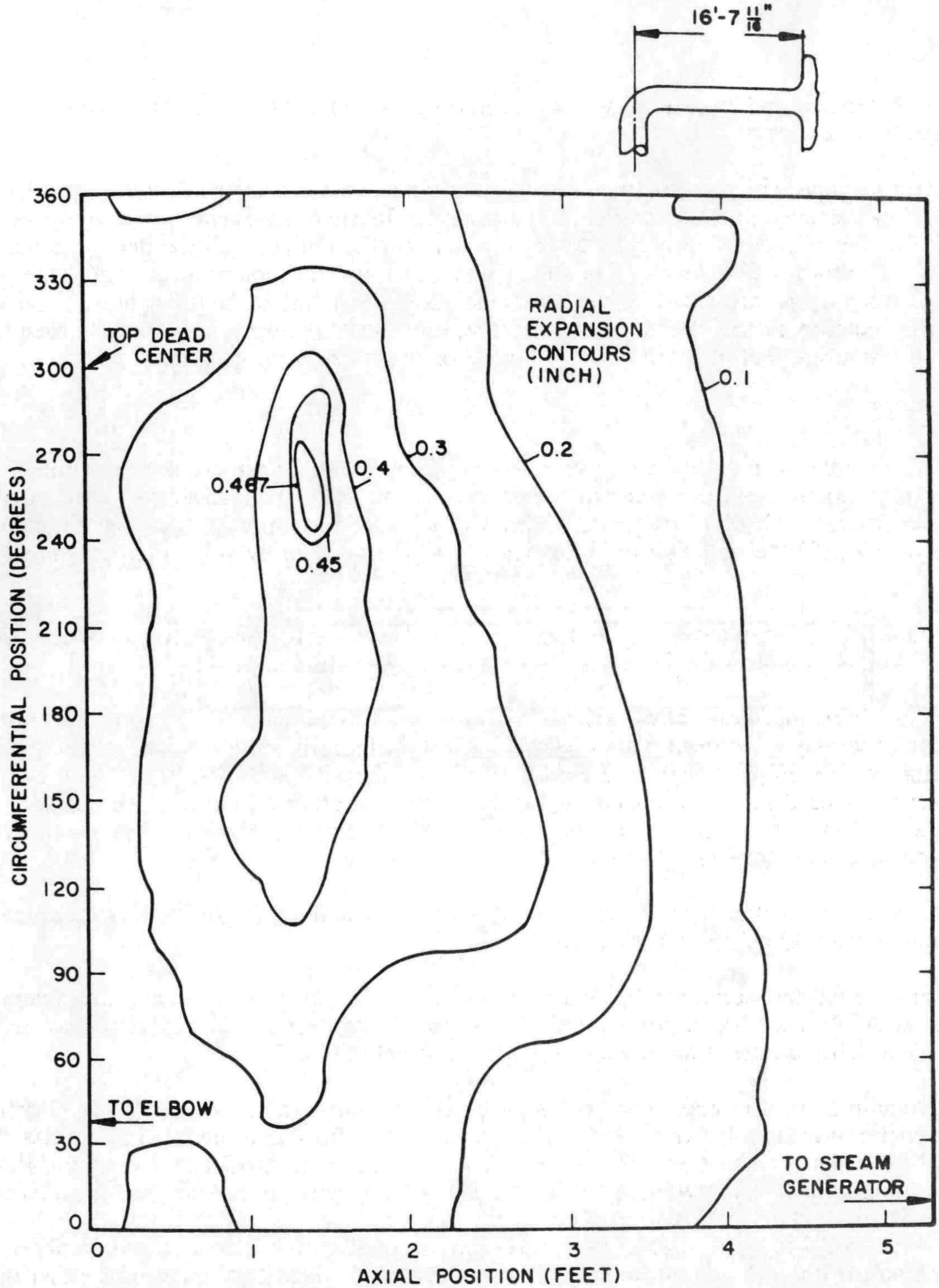


Figure 1.8 RADIAL GROWTH OF #2 FEEDWATER LINE UP TO STEAM GENERATOR #2

The event center is probably the horizontal stretch of feedpipe (at elev. 104'9") leading up to steam generator #2.

For a horizontal pipe which leads to a steam generator and which has suffered severe damage, a subcooled water slug event is a probable scenario. In such an event, pressure waves can propagate in one direction only – down the liquid–filled pipe. Since feedpipe damage occurred both within a few feet of the steam generator and the containment wall, the entire feedpipe leading up to the steam generator must have been full of liquid water. The event center is the location of the steam/water interface, and must therefore be located either in the feedpipe within a few feet of the feedwater nozzle or in the feedring itself.

FLUID STATE

A possible subcooled water slug event scenario has already been postulated. Two things must have been true about the fluid state in the feedwater and steam generator if such an event actually occurred: (1) high pressure steam must have been present in the feedpipe or feedwater nozzle, (2) the water in the feedpipe must be significantly subcooled relative to the steam.

The feedwater and steam generator systems are relatively well–instrumented. A significant amount of plant data are available to assist in evaluating the fluid state.

The water levels in the three steam generators are shown in Figure 1.9 for about ten minutes during which the event occurred. Also indicated in the Figure is the elevation of the center of the feedring and feedpipe. Note that the precision of these measurements is unknown, and conclusions must be drawn cautiously. In both steam generators 1 and 2, the indicated water level dipped below the bottom of the feedpipe. In both cases steam may have entered the feedring and feedpipe, depending on the rate of feedwater flow.

The steam pressure in the three steam generators is indicated in Figure 1.10. Pressure was high and exceeded 900 psig in all three units.

The temperature of the auxiliary feedwater entering the steam generator was not measured. However, all AFW was drawn from the AFW storage tank which is at ambient temperature. Thus the AFW temperature is assumed to be approximately 80°F.

Data is available from the feedwater flow sensors and is presented in Figure 1.11. However, the flow sensors are intended to indicate normal feedwater flow and are grossly inaccurate at the small flowrates provided by the AFW system. However, auxiliary feedwater flow is controlled automatically following a feedwater trip. The three loops are thus automatically supplied with 420 gpm of auxiliary feedwater. If this flow splits uniformly, each steam generator received 140 gpm. This flow rate and its distribution are imprecise and can be altered by manual control. Unfortunately, there is no known record of operator actions in this instance.

The feedwater flow data, though inaccurate, does have one significant feature. The flow reading from the #2 feedpipe has a large fluctuation soon after the water level in steam generator #2 fell below the feedpipe. This spike may indicate the occurrence of the first subcooled water slug impact.

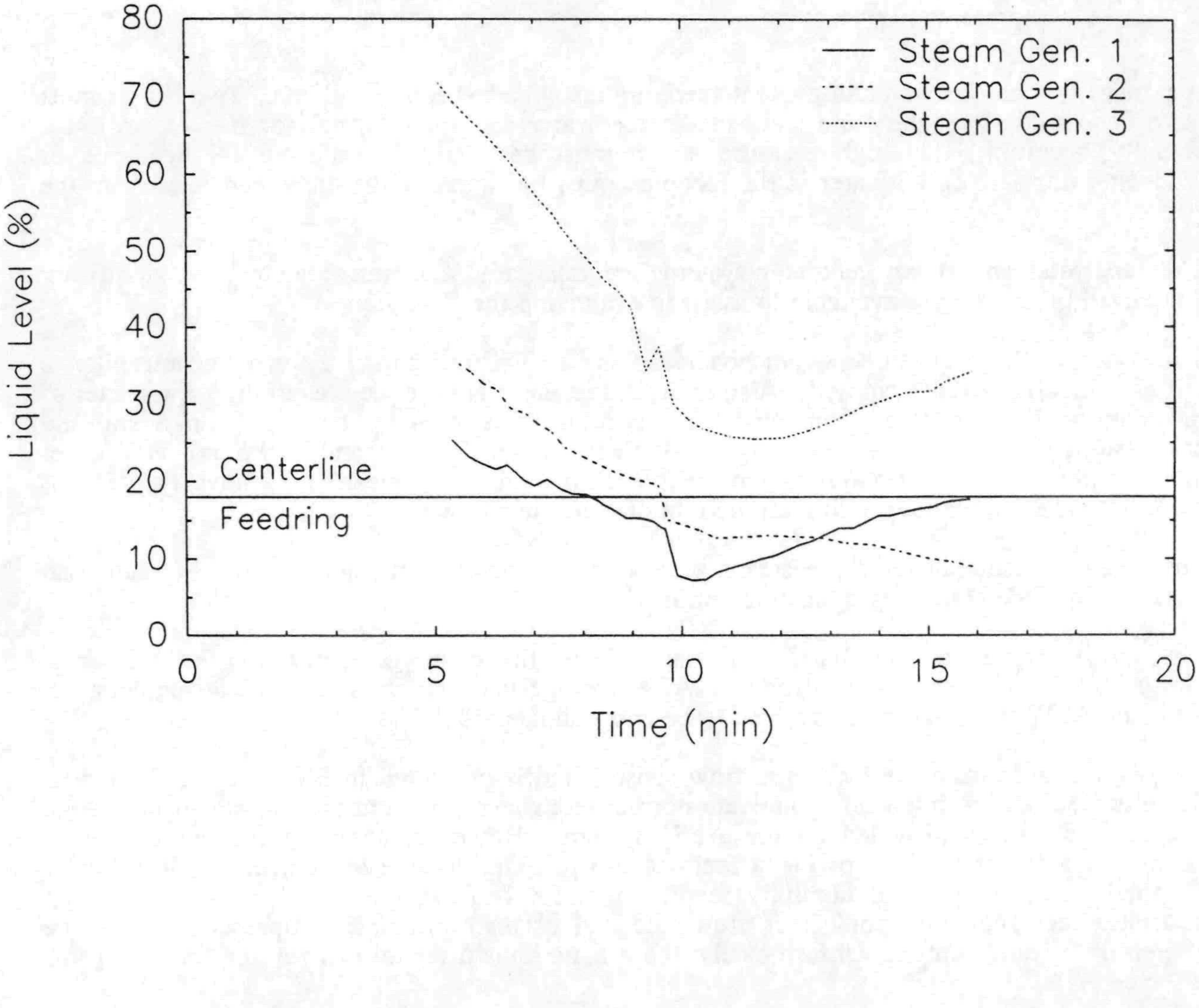


Figure 1.9 RECORD OF STEAM GENERATOR WATER LEVELS

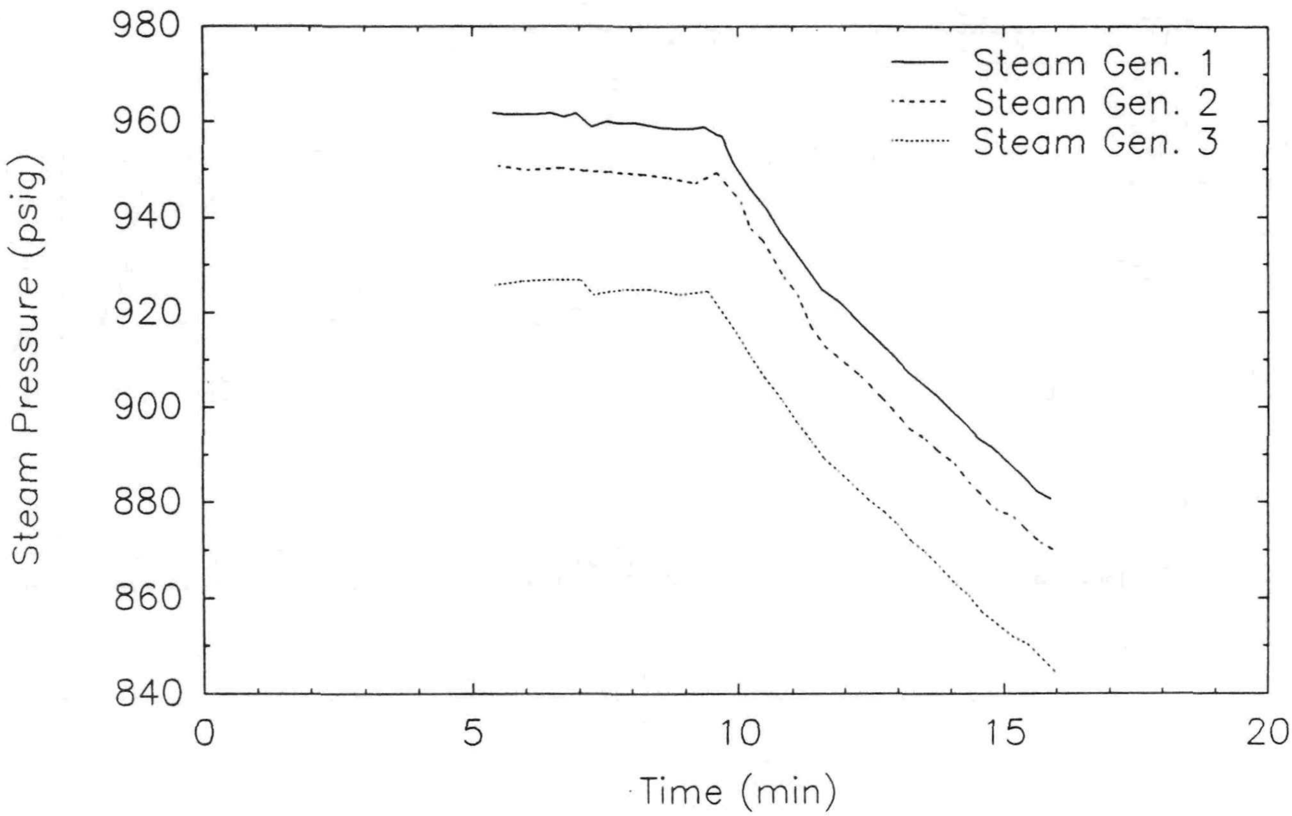


Figure 1.10 RECORD OF STEAM GENERATOR PRESSURES

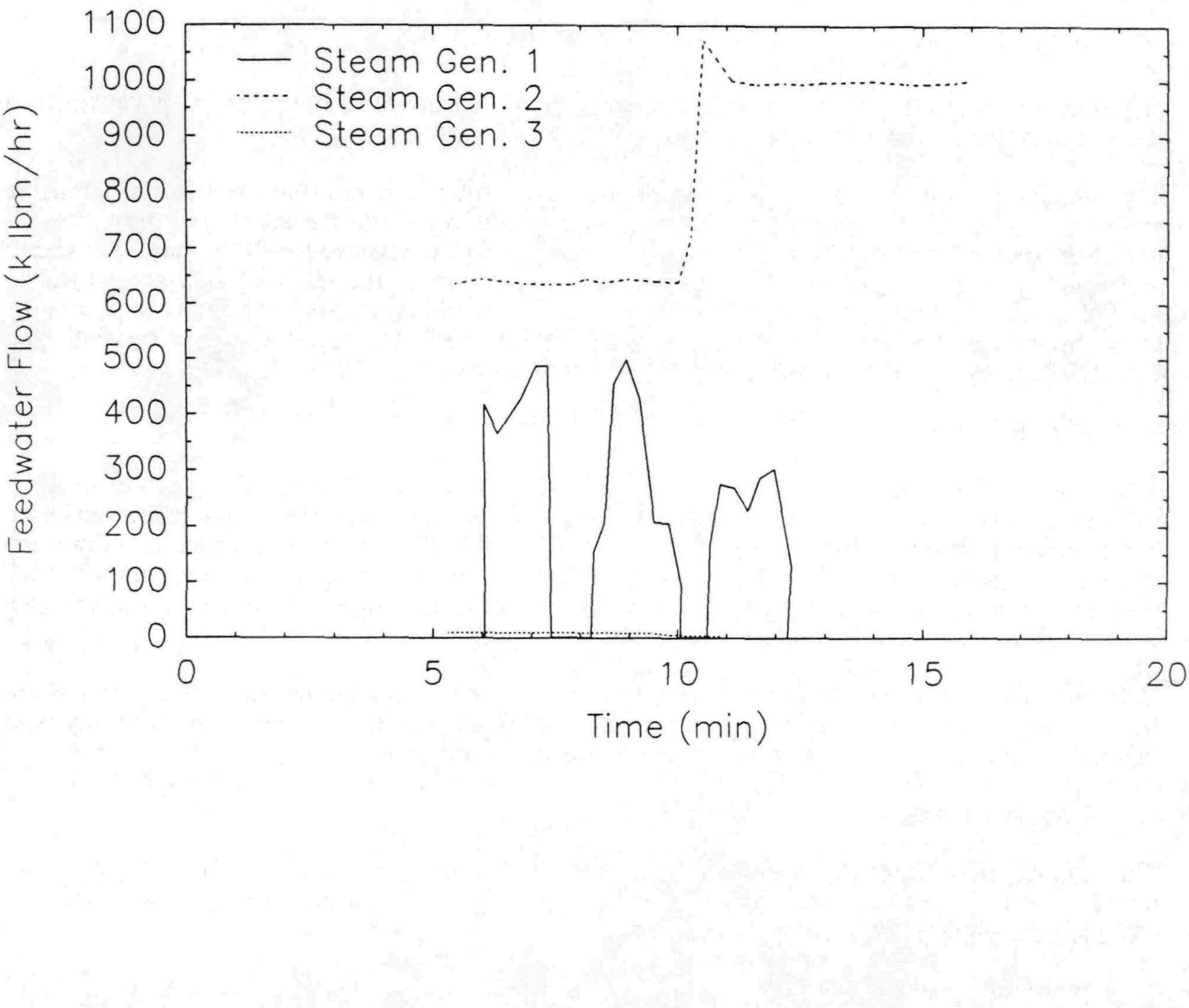


Figure 1.11 RECORD OF FEEDWATER FLOW

Thus, the fluid state prior to the event satisfies both conditions (high pressure steam and subcooled water) necessary for a subcooled water slug event.

EVENT SCENARIO

Based on the above evaluation of the fluid state at the event center, a subcoled water slug event scenario is proposed. The presumed sequence of events within the feedring is illustrated in Figures 5.3 through 5.6 in Volume 1. Note that there are some major uncertainties in this scenario, particularly regarding void and slug formation. Resolution of these uncertainties is deferred to the confirmation stage.

1. Void formation

A steam void forms in the feedpipe or nozzle of the #2 steam generator after the water level in the steam generator falls below that of the feedring.

This step in the scenario involves a crucial assumption that can only be verified by extensive analysis and/or confirmatory tests: namely that the flow rate into the steam generator was so low that part of the feedring would drain. However, the probable flow into the steam generator (140 gpm) is much less than the flowrate for which the feedring is designed (up to 16,000 gpm). Scoping calculations (see below) indicate this is far less than the flow necessary to maintain the feedring full of liquid. It is sufficient for now to carry on with the investigation under the assumption that the feedring drains.

2. Slug formation

After the feedring partially drains, a free surface of subcooled water is exposed to high pressure steam. The hot steam rapidly condenses on the auxiliary feedwater in the feedpipe and nozzle. As a result, large volumes of steam flow over the free water surface in a direction opposite the AFW flow. This rapid flow generates waves on the liquid surface, one of which eventually comes into contact with the top of the feedpipe and traps a bubble of hot steam (see Figure 5.8.). This wave is the nucleus of the water slug.

This step also involves a crucial assumption, namely that counter–current steam and water flow in the feedring and nozzle will give rise to slug flow conditions. We assume for now that this is true, and leave final verification to the confirmation stage.

3. Slug acceleration

The trapped bubble rapidly condenses, its pressure falling very quickly. The slug of water now has virtually zero pressure on the bubble side and 950 psig on the steam generator side. It is rapidly accelerated into the bubble region.

4. Void collapse

The steam which is left in the bubble condenses rapidly on the turbulent water surface. The void collapses in front of the accelerating slug.

5. Impact

The slug of water has accelerated to very high velocity because its mass is small and the forces on it are great. The steam bubble has rapidly condensed and provides no cushioning of the impact. As a result, a very large pressure wave is generated as the slug slams into the liquid column further down the feedpipe.

SCOPING CALCULATIONS

Some of the uncertainties in the event scenario can be partially resolved by scoping calculations.

1. Void formation in the feedring

It is possible to estimate the minimum feedwater flow necessary to maintain the feedring full of water. If the feedring is full, the bottom discharge holes should behave as sharp–edged orifices with a contraction coefficient C_c of approximately 0.6. At the lower flow limit the discharge head is purely hydrostatic, so that the discharge velocity through the hole is $V = \sqrt{2gh}$, where h is roughly the diameter of the feedring. For steam generator #2 then, the discharge velocity is about 8 ft/sec. The flow rate is: $Q = C_c A_h V$, where A_h is the total discharge area. Steam generator #2 has 250 holes of diameter 3/4", and a flowrate of 1,500 gpm results.

Thus, the flow necessary to keep the feedring full of liquid is greater than the total auxiliary feedwater flow to all three steam generators. It is likely that a void did indeed form in the feedring of the #2 steam generator.

2. Void formation in the feedpipe

It is useful to examine the Froude number in the horizontal feedpipe leading up the steam generator #2. The flowrate is estimated at 140 gpm and the pipe diameter is 18 inches. Referring to Figure C.2 in Volume 1, we see that the Froude number in this situation is considerably less than 0.1. Thus we conclude that should the feedring have drained, a stratified flow would have developed in the horizontal feedpipe leading up to steam generator #2.

3. Slug acceleration and impact

The range of possible waterhammer overpressures due to impact of the water slug is estimated from Figure C.7 in Volume 1. The initial lengths of the slug and the void are unknown. Under these uncertain conditions, the "base overpressure" P_o (from Figure C.7) provides a rough estimate of the overpressure. The differential pressure across the slug is very close to the steam generator pressure, or 950 psi. The base overpressure P_o from Figure C.7 is thus approximately 17,000 psia (using the 300 F curve).

CONCLUSION OF THE INITIAL DIAGNOSIS

A subcooled water slug event scenario is likely. This scenario is backed up by plant data and by some scoping level analysis. However, there are important gaps in the diagnosis. Primarily, it is still not clear that a water slug could have formed. This question is addressed in the confirmation stage.

1.6 CONFIRMATION

Extensive confirmation activities were undertaken for this diagnosis. The reasons were twofold: (1) the damage is quite severe, and (2) significant uncertainties remain regarding the event scenario. A better understanding of the physical mechanisms of this event is required in order to formulate effective preventive measures. Three major confirmatory activities were undertaken: scale model laboratory tests, analysis, and in–situ tests.

SCALE MODEL TESTS

The reactor vendor performed experiments using a scale model of the feedwater system near steam generator #2. The purpose of these experiments was to confirm qualitatively the mechanism of slug formation. In the absence of a general method for analyzing complex two–phase flows such as those in the draining feedring, confirmatory tests such as this are often the most practical way to demonstrate that a phenomenon is physically possible.

The test apparatus is constructed from glass and Plexiglas, as illustrated in Figure 1.12. A portion of the feedring is simulated by a straight section of clear Plexiglas having a series of flow holes along the underside. A second straight run of clear Plexiglas representing the feedwater piping makes a tee–junction at the mid–section of the Plexiglas header. Air and water were used to simulate the two phase flow in the feedring. A vacuum line and water trap are connected to a port on the upper side of the simulated feedwater piping.

Water is pumped into the apparatus and allowed to partially fill the feedring and drain through the flow holes. When a steady flow is achieved, the vacuum line is activated and air exhausted from the free pipe volume over the water surface. The slug behavior observed in the device is illustrated by Figure 1.13. A rippling, wave–like surface forms on the flowing water. As more flow holes are covered with water, air bubbles are observed entering the ring header and rising through the water. The water surface soon becomes more agitated and develops a chugging flow. Pulses of water completely fill the feedwater pipe over a short length of pipe, trapping an air void in front of the vacuum line. The air void collapses and the slug is accelerated through the piping to the vacuum port.

The scale model test demonstrates that counter–current two–phase flow can generate slugs in a system similar to the feedwater system near steam generator #2. Even though results from this test are not applicable in a quantitative sense to the actual feedwater system, the uncertainty in the diagnosis has been substantially reduced.

Further tests were conducted in a 1/10–scale model of the feedwater system to suggest relevant phenomena and provide limited confirmation of analytical models under development.

The 1/10–scale model apparatus is illustrated in Figure 1.14. It consists of a 12" ID steel vessel simulating the steam generator vessel and a segmented length of straight pipe entering the vessel which simulates the feedpipe and the feedring. The feedring and sparger consist of a four foot section of 1.5" sch. 40 steel pipe with ten 0.375" diameter downward–facing holes spaced on one inch centers. During the tests, the vessel was maintained at pressures ranging from 17 to 75 psia. Feedwater temperature varied from 65 to 190 F. The primary measurements are the pressure history in the feedpipe and the overpressure due to slug impact. The feedring could be replaced with a section of acrylic tubing for flow visualization through a viewing window in the simulated steam generator vessel.

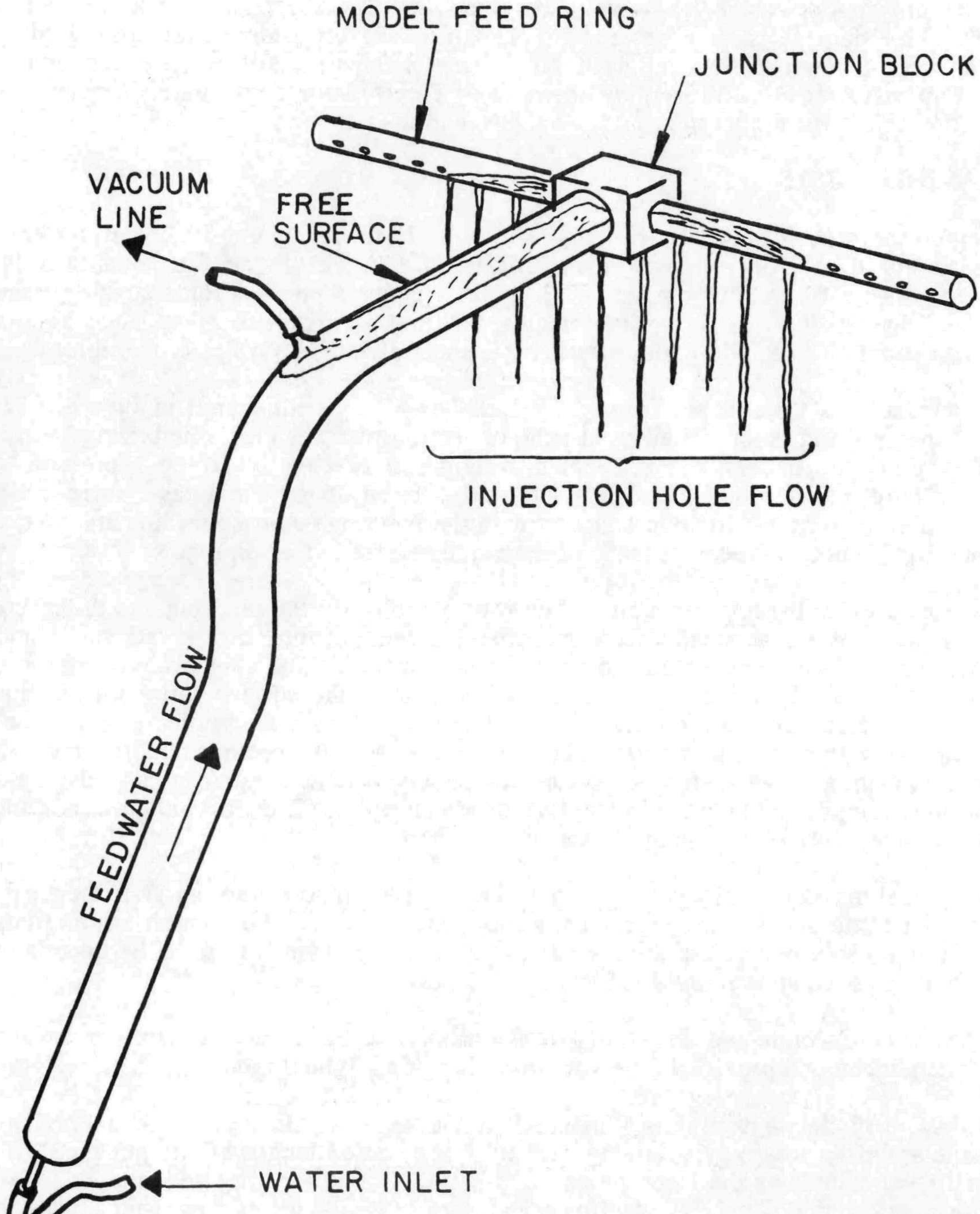


Figure 1.12 SKETCH OF GLASS AND PLASTIC MODEL FEEDWATER SYSTEM

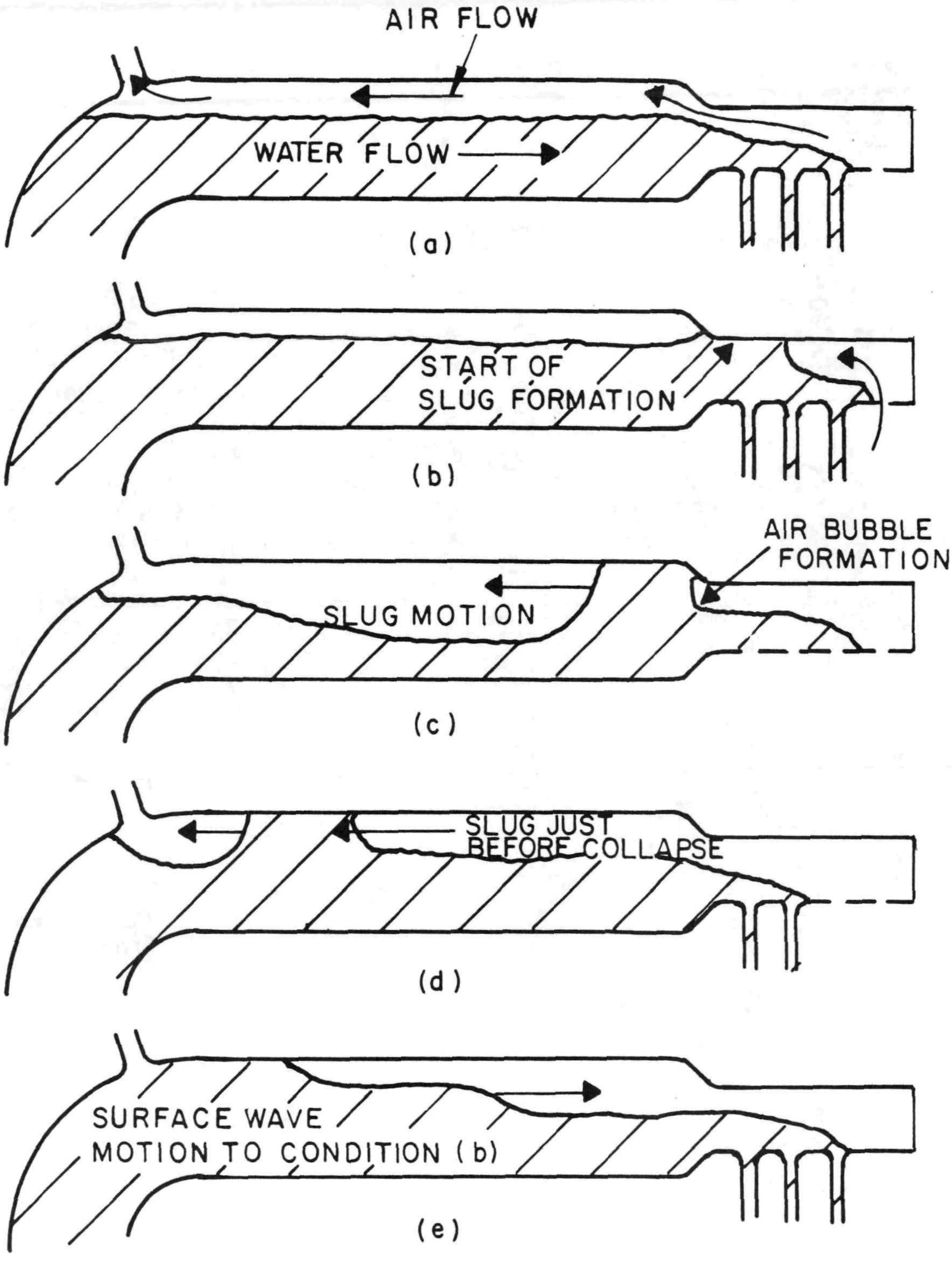


Figure 1.13 EXPERIMENTALLY OBSERVED SLUGGING MECHANISM

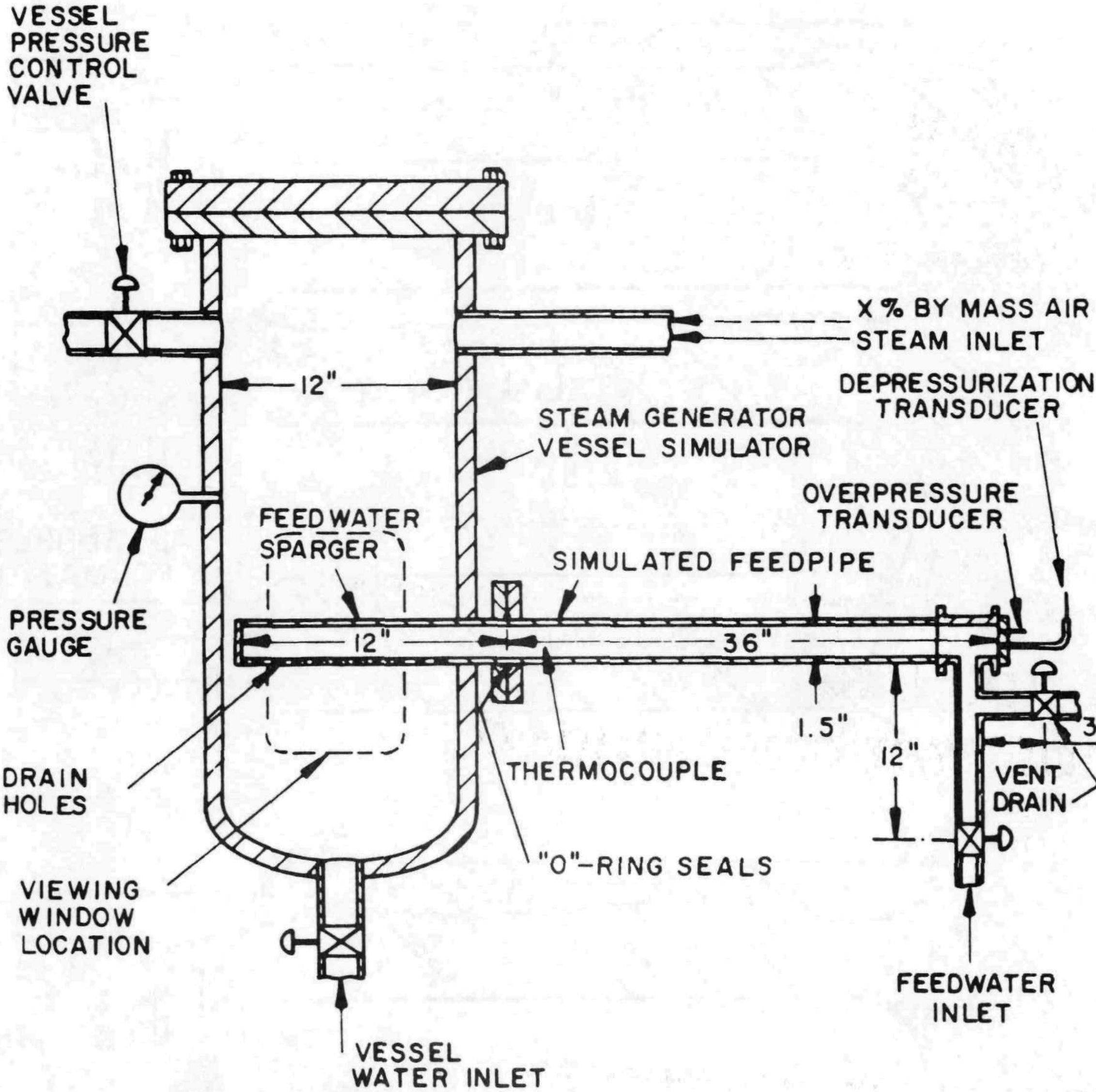


Figure 1.14 SKETCH OF 1/10th SCALE STEAM GENERATOR MODEL

A wide range of tests were performed in the 1/10–scale model. Flow patterns and waterhammer overpressures were observed for a variety of fluid conditions and sparger designs. Some of the major results are summarized in Figures 1.15 and 1.16. Analytic models for flow in the feedring were tested against experimental results, as illustrated in Figure 1.15. This Figure shows measured and predicted water depth in the feedring as a function of total liquid and steam flow. The predictions of "critical flow theory" discussed in the next section were in good agreement with experimental measurements. The validated critical flow theory enables prediction of the flow in the feedring when some of the discharge holes are uncovered. Additional analytic work led to a theory for the onset of waterhammer in low AFW flow situations. Predictions of this "flow threshold theory" are compared with experimental results in Figure 1.16. Agreement is fairly close, implying that the theory can be used to estimate whether waterhammer could have occurred in actual event.

The primary conclusions from the 1/10–scale model are that water slugs can form following feedring drainage and that rapid condensation results in rapid acceleration. Overpressures of order 500 to 1,000 psi were observed even in the small scale vessel with steam pressure close to atmospheric. Additionally, test results were used to validate analytic models for flow in the feedring and the onset of waterhammer.

ANALYSIS OF SLUG FORMATION MECHANISMS

Detailed analyses of slug formation were undertaken for several reasons: (1) to aid in the design of small scale experiments, (2) to provide scaling techniques from small scale experiments to full scale equipment, and (3) to provide a basis for designing feedwater systems which will not suffer from severe waterhammer. The goal of the analysis was to predict slug formation based on system design and operating parameters. This section presents the main results from this analysis.

1. Feedring Hydraulics

The steady state characteristics of the feedring under low flow rate conditions were analyzed. The purpose was to predict the void fraction in the feedring under conditions of low AFW flow. The two important parameters are the water depth upstream of the first feedring drainage hole and the number of holes through which water is draining.

A model for the water depth was developed based on open–channel hydraulic theory. The model was found to agree well with measured water depth from the 1/10–scale air/water test facility. Experimental data and model predictions are compared in Figure 1.15. Predicted water levels fall close to all the measured values up to the point of slug formation. The depth in the horizontal pipe was fairly constant up until 2–4 inches prior to the first drainage hole.

Another analytical model was developed to predict the number of feedwater holes draining. The model neglects friction in the feedring and estimated the number of draining holes using an average discharge coefficient based on empirical evidence taken from the 1/10–scale hydraulic model. Theoretical predictions of the number of draining holes agreed quite well with measurements from the 1/10–scale facility, as illustrated in Figure 1.17. The horizontal axis is proportional to the water flow rate, while the vertical axis is proportional to the number of draining holes (m) and geometrical parameters.

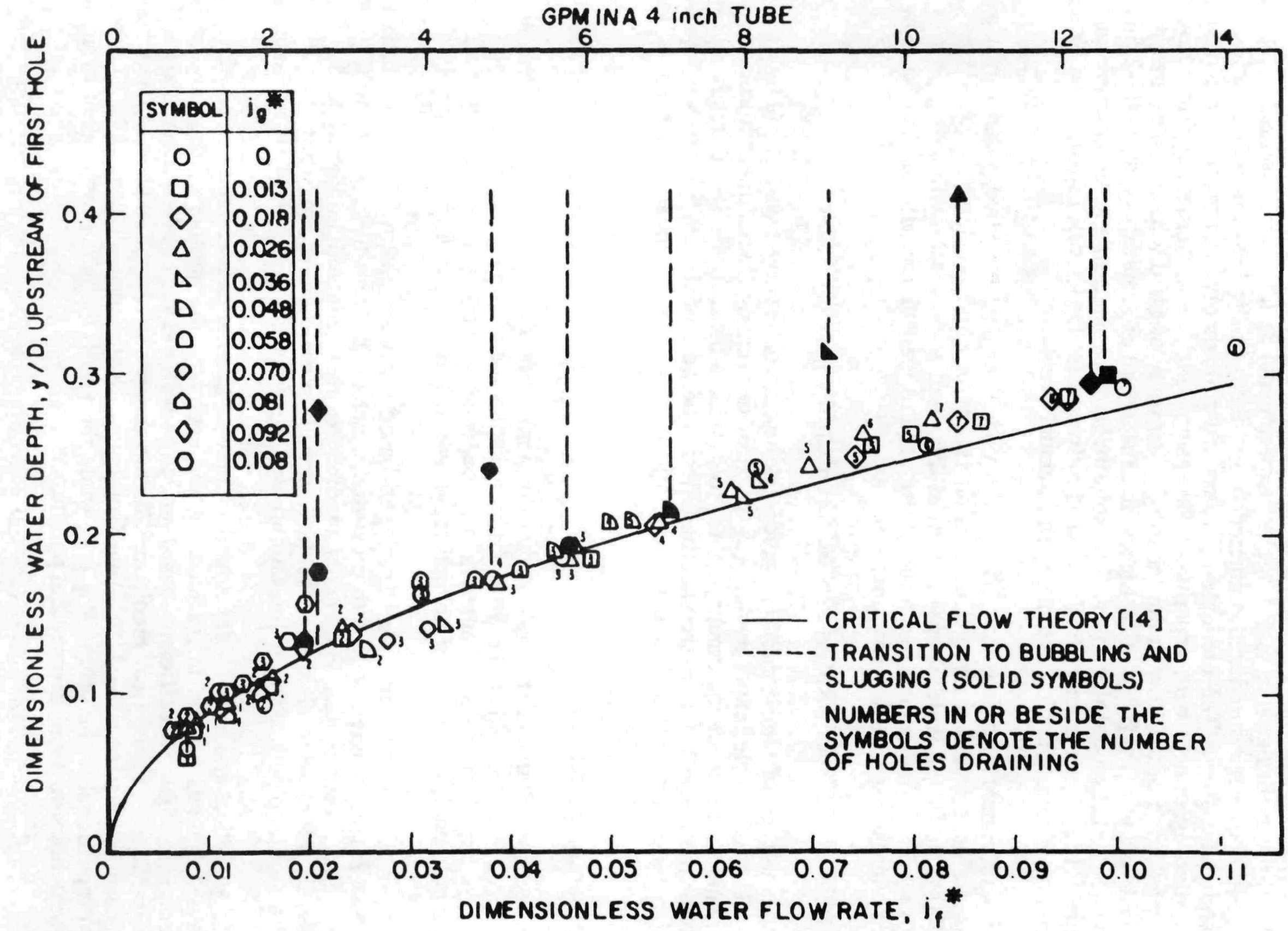


Figure 1.15 COMPARISON OF MEASURED AND PREDICTED VALUES FOR THE WATER DEPTH BEFORE THE FIRST DRAINAGE HOLE (1/10th SCALE STEAM GENERATOR)

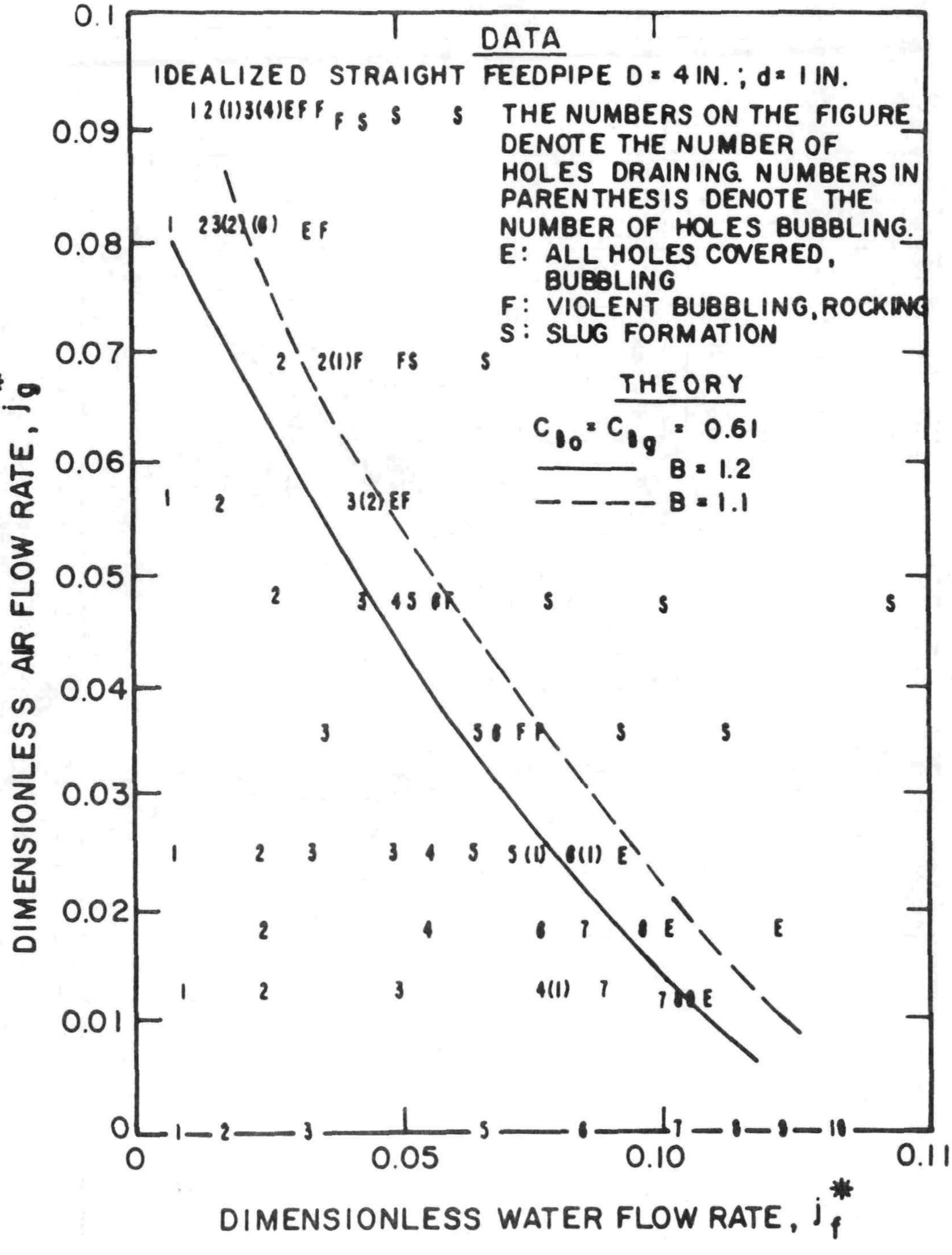


Figure 1.16 COMPARISON OF OBSERVED AND PREDICTED OPERATING REGIMES FOR SLUG FORMATION

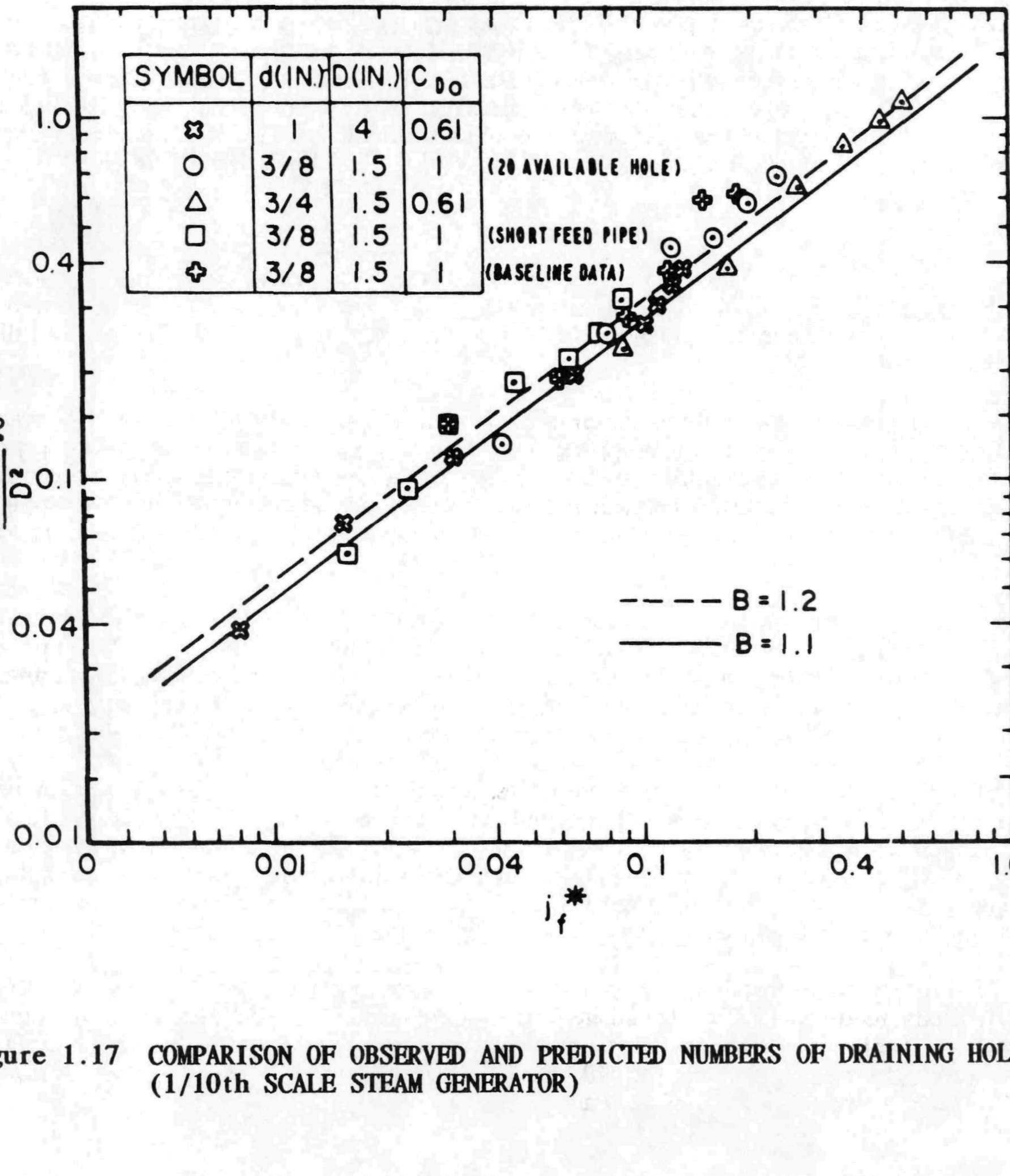


Figure 1.17 COMPARISON OF OBSERVED AND PREDICTED NUMBERS OF DRAINING HOLES (1/10th SCALE STEAM GENERATOR)

2. Slug Initiation

Analysis of counter–current gas/liquid flows in the feedring predicted a hydraulic instability leading to slug formation. The theory allows prediction of an operating regime in which slugs will form, as illustrated in Figure 1.16. Dimensionless water and air flow rates are the axes. The solid line represents the theoretical boundary between stable (lower left) and unstable (upper right) operating regions. The 1/10–scale hydraulic facility was used to investigate operation at a number of operating points shown in the figure. Those points where slugs were observed to form are indicated with an "S," points with violent bubbling and rocking are indicated with an "F," and points with all holes covered and air bubbling up through the water are indicated by "E." Numbers indicate stable operating points, with that number of holes draining water. Inspection of the plot shows good agreement between the predicted and observed unstable operating regimes.

IN SITU TESTS

Scale model tests have shown that the proposed event scenario is plausible and have provided data for validating analytic models. They provide enough confirmation to redesign the system to prevent another similar event. However, these fixes can only be completely proven by full scale tests at the plant.

Prior to initiating the tests, the horizontal run of piping leading up to steam generator #2 was shortened from 17 feet to 4 feet by dropping a section of pipe by approximately one pipe diameter (see Figure 1.3). Feedpipes leading to the remaining steam generators were not altered. An extensive test program was carried out to verify the adequacy of the new piping geometry and operational procedures The test program ultimately required four months to complete.

Extensive high response pressure, acceleration and strain instrumentation was installed throughout the feedwater system. Scratch gauges were installed to record peak piping displacements and a few thermocouples were installed on the outside surface of the piping. Steam generator water level and feedwater flow rate were recorded during the testing, and plant personnel were stationed at various points to observe or hear evidence of waterhammer.

Testing commenced and two tests were completed successfully (without any evidence of waterhammer) with the reactor subcritical and with the reactor critical at 7% power. A final test was planned for a reactor trip from 10% power. However, before this test could be run, the reactor tripped inadvertently from 35% power and there was extensive indication of a mild, non–damaging waterhammer event originating in SG #1. The planned test was aborted at this point, and the test evidence was compiled as Phase I of the overall program.

Phase II of the test program was a series of exploratory tests conducted to investigate the effect of auxiliary feedwater in one steam generator at a time. The test sequence and results are indicated in Table 1.2. Two non–damaging waterhammer events were recorded (Runs 6 and 13) at the highest flow rate tested (240 gpm). Waterhammer was not indicated in nine tests at flow rates between 75 and 100 gpm and in two other tests at 240 gpm.

Table 1.2 PHASE II TEST SEQUENCE AND RESULTS (Numbers in Table are Run Number)			
Auxiliary Feedwater Flow (gpm)	Steam Generators (Horizontal Pipe Runs, Feet)		
	1 (7 ft)	2 (4 ft)	3 (12 ft)
75	1	–	3
150	4	–	7
200	5	12	8
240	6*	13*	9

* Waterhammer was indicated conclusively in this run. There was no indication of waterhammer in unmarked runs.

The waterhammer events recorded during the Phase II test program occurred in SG#1 and SG#2, the two loops involved previously. These loops had the shortest horizontal pipe runs and both were within the vendor guideline.

Records of steam generator water level were examined for each of the three waterhammer events that occurred during the Phase I and II tests. Each waterhammer event occurred when the water level was approximately at the center of the feedring. The precision of the water level indication is unknown, but it is unlikely to be so poor as to alter the prime conclusion that the feedring was covered or being covered at the indicated time of each of the waterhammer events. (The time of the event was determined by rapid verbal communication with personnel stationed inside the containment.) In each case there is a nearly coincident decrease in water level within the vessel, as might occur if water within the vessel were rapidly drawn in to fill the feedwater piping. Crude calculations indicate that the water volume decrease within the vessel is consistent with refilling the feedring and associated piping. Thus, there is a framework of direct and indirect evidence that suggests that waterhammer events recorded during these tests occurred as of some few minutes after the bottom discharge holes in the feedring were covered by the nominal water level.

At the conclusion of Phase II of the test program, plant personnel decided to install J–tubes on the feedring. The exploratory Phase II program must be considered a success in the sense that it generated useful experimental evidence. However, it did not lead to a verified operating procedure. Instead, a previously untried hardware modification was preferred.

The final Phase III of the test program was intended to verify that the waterhammer effect which caused the original feedwater line incident would not recur. Preliminary tests were conducted to measure the drainage rate under "cold" non–operating conditions. The data of Figure 1.18 were obtained.

A test was conducted individually on each of the four steam generators with the reactor subcritical and the plant in hot shutdown condition. There were no indications of waterhammer during these tests.

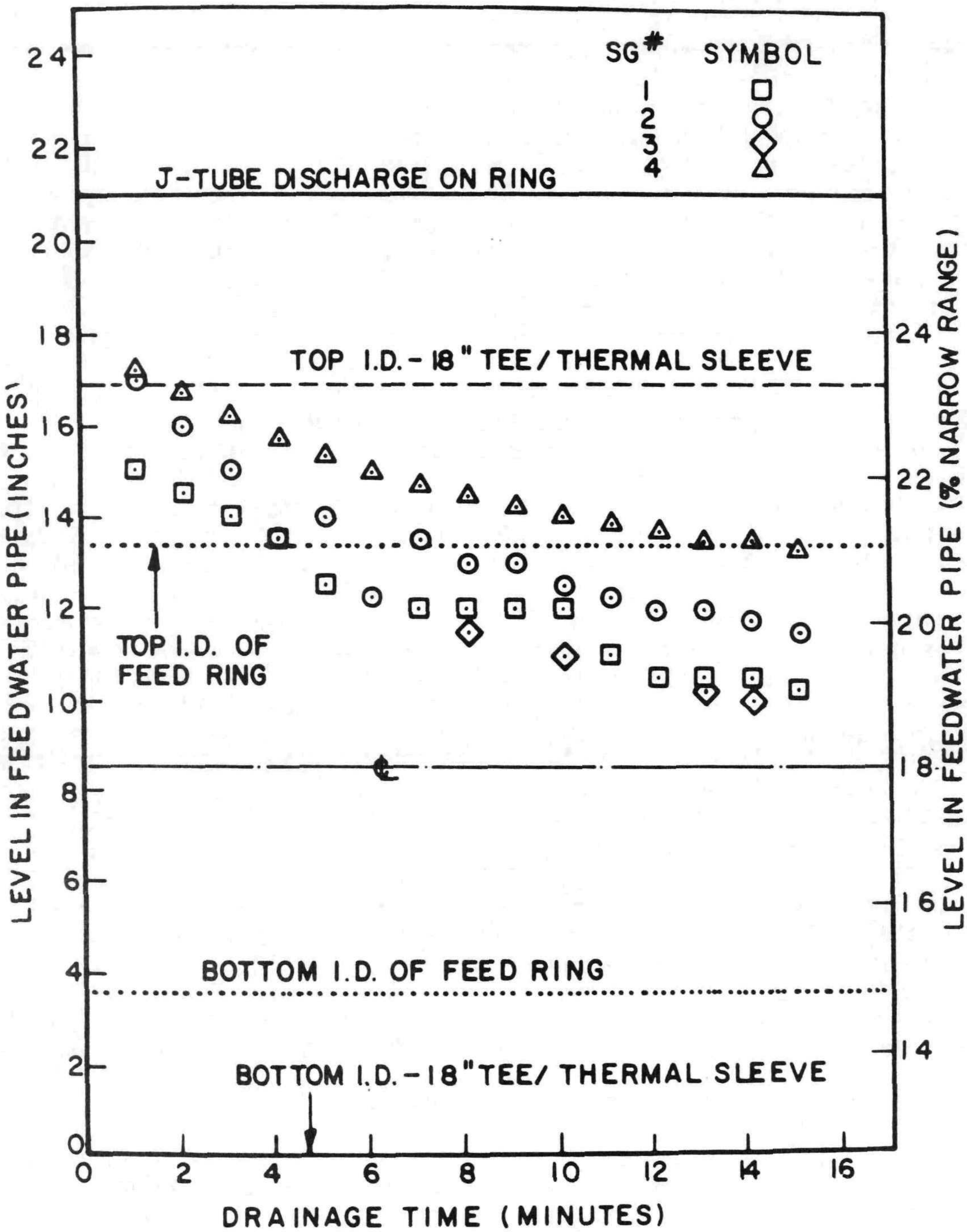


Figure 1.18 COLD DRAINAGE DATA FROM PHASE II, IN-SITU TESTS

In each test, the water level was lowered to approximately eight inches below the bottom of the feedwater pipe, and then raised to recover the feedwater pipe. While the water level was being lowered (by blowdown), auxiliary feedwater flow to the generator was maintained and presumably the feedring remained full. With the water level below the feedwater pipe, auxiliary feedwater flow was stopped and restarted twice with intervening drainage intervals of five minutes the first time and ten minutes the second time. The actual water levels in the feedrings during any of the Phase III verification tests are unknown. (The drainage curve of Figure 1.18 indicates that the top two inches of the feedring (top five inches of the feed pipe) would be expected to drain in ten minutes with the plant "cold".) Feedwater flow rates were not measured during the Phase III tests, but may be deduced from the valve position indication. The normal (50%) preset operating point used during these tests is believed to correspond to a flow rate of approximately 140 gpm. Thus, in the Phase II verification tests with the reactor subcritical, only limited drainage periods were employed and the feedwater flow was controlled at a rate where waterhammer had not occurred during the previous Phase II tests.

Three further tests were performed with the reactor at power levels of 7%, 35%, and 100% in order to provide realistic simulations of potential abnormal operating conditions realistically with all instrumentation still installed. There was no indication of waterhammer during these tests. Each test was initiated by lowering the level in one or more steam generators until a low–low level reactor trip occurred. In the 7% power test, the J–tubes never uncovered in SG#1 and the level in SG#2 began to rise (suggesting that the feedring was full) only one minute after the reactor trip. The feedrings in SG#1 and SG#2 were uncovered for a total of twenty to thirty minutes after the trip from 35% power and the water level did not begin to rise for approximately fifteen to twenty minutes after the feedrings were first uncovered. The timing and rate of water delivery to the feedring is not reported, but the water level records again suggest that the feedring was refilled at approximately 140 gpm. Available thermocouple records suggest that there was steam in the upper part of the feedrings for roughly ten minutes during this test. For the trip from 100% power, the records only indicate that the SG#1 and SG#2 feedrings were uncovered. The recovery traces are not shown. One of the available thermocouple records suggests that cold feedwater was supplied to SG#1 within four minutes after the reactor trip from 100% power.

In summary there was only a limited drainage period and quite possibly a low feedwater flow rate during the Phase III tests. Moreover, there were only three tests and these were limited to a single set of operating procedures intended to be typical of recovery from a reactor trip. Therefore, although the Phase III tests constitute a meaningful limited verification of procedures at that plant, these tests taken alone are by no means sufficient to confirm that the J–tube modification will be effective over the entire range of credible operating circumstances at any plant.

CONCLUSION OF CONFIRMATION

Due to the serious damage resulting from this waterhammer, extensive confirmation activities were carried out. These activities accomplished the following:

1. Scale model tests demonstrated the plausibility of the event scenario and provided validation for analytic models,

2. Analysis provided design methods to prevent recurrence of the event, and

3. In–situ tests provided final proof that the problem had been resolved in the full–scale system.

This plant has operated for nearly 15 years without recurrence of this event.

1.7 DISCUSSION

Damage from this type of "steam generator waterhammer" is severe because the differential pressures acting on the water slugs are quite large (implying a high accelerating force) and the slugs are relatively small (with little inertia to resist motion). As a result, high slug velocities are achieved prior to impact, yielding extremely high overpressures.

PWR owners have largely fixed this problem since the first few occurred in the early 1970's. However the potential for similar events still exists in other reactor systems. The basic requirements are horizontal lines leading to high pressure steam reservoirs, and the potential to refill these lines with subcooled water.

2 A SUBCOOLED WATER SLUG EVENT IN A PWR FEEDWATER SYSTEM

This case is based on a subcooled water slug event which bent and cracked an 18 inch feedwater pipe in a pressurized water reactor power plant.

2.1 PURPOSE OF THIS CASE

This case is presented to:

1. Illustrate extensive damage from a subcooled water slug event,

2. Illustrate plant data recorded from such an event,

3. Illustrate a comprehensive timetable of events, and

4. Illustrate extensive confirmation activities.

2.2 SYSTEM DESCRIPTION

This event involves the feedwater and auxiliary feedwater system.

FEEDWATER SYSTEM

The feedwater system is similar to that discussed in the previous case and illustrated schematically in Figure 1.1. An isometric diagram showing feedwater loop "B," which was most affected by the event, is presented in Figure 2.1. The diagram shows that inside the containment building the feedline consists of about 170 feet of horizontal piping at el. 31'6", leading to steam generator B. The line ends at a riser leading to the steam generator feedring at el. 41'5". Piping supports are found roughly every 20 feet along the feedline.

The feedwater control station for loop B is shown in Figure 2.2. The control station is located just outside the containment building, and consists of the main feedwater regulating and isolation valves, as well as a bypass line and associated valves for operating at low flow rates. The junction with the auxiliary feedwater system is shown, which joins the main feedline several feet before the containment penetration.

AUXILIARY FEEDWATER SYSTEM

The auxiliary feedwater system, which is illustrated by the schematic diagram in Figure 1.4, consists of a motor–driven pump, a turbine–driven pump, the auxiliary feedwater tank, and associated valves, piping and instrumentation. Flow is from the AFW tank through individual suction lines to the AFW pumps, which discharge through independent check and isolation valves to the three main feedwater loops. The system is actuated automatically if the narrow range level in two of the three steam generators indicates less than 5 percent, which is expected after a reactor trip from full power. The system may also be activated manually.

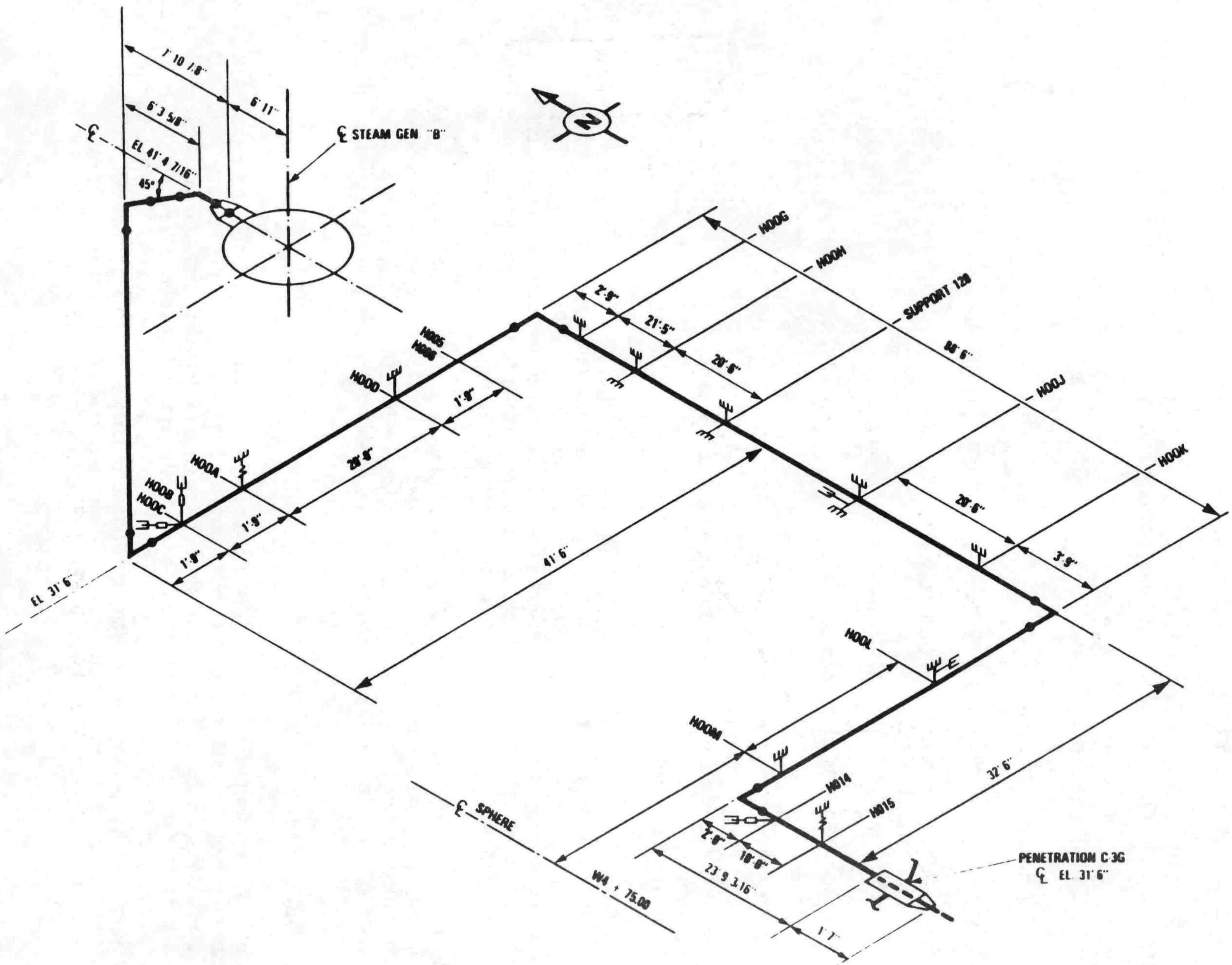


Figure 2.1 FEEDWATER LOOP B PIPING AND SUPPORT LAYOUT

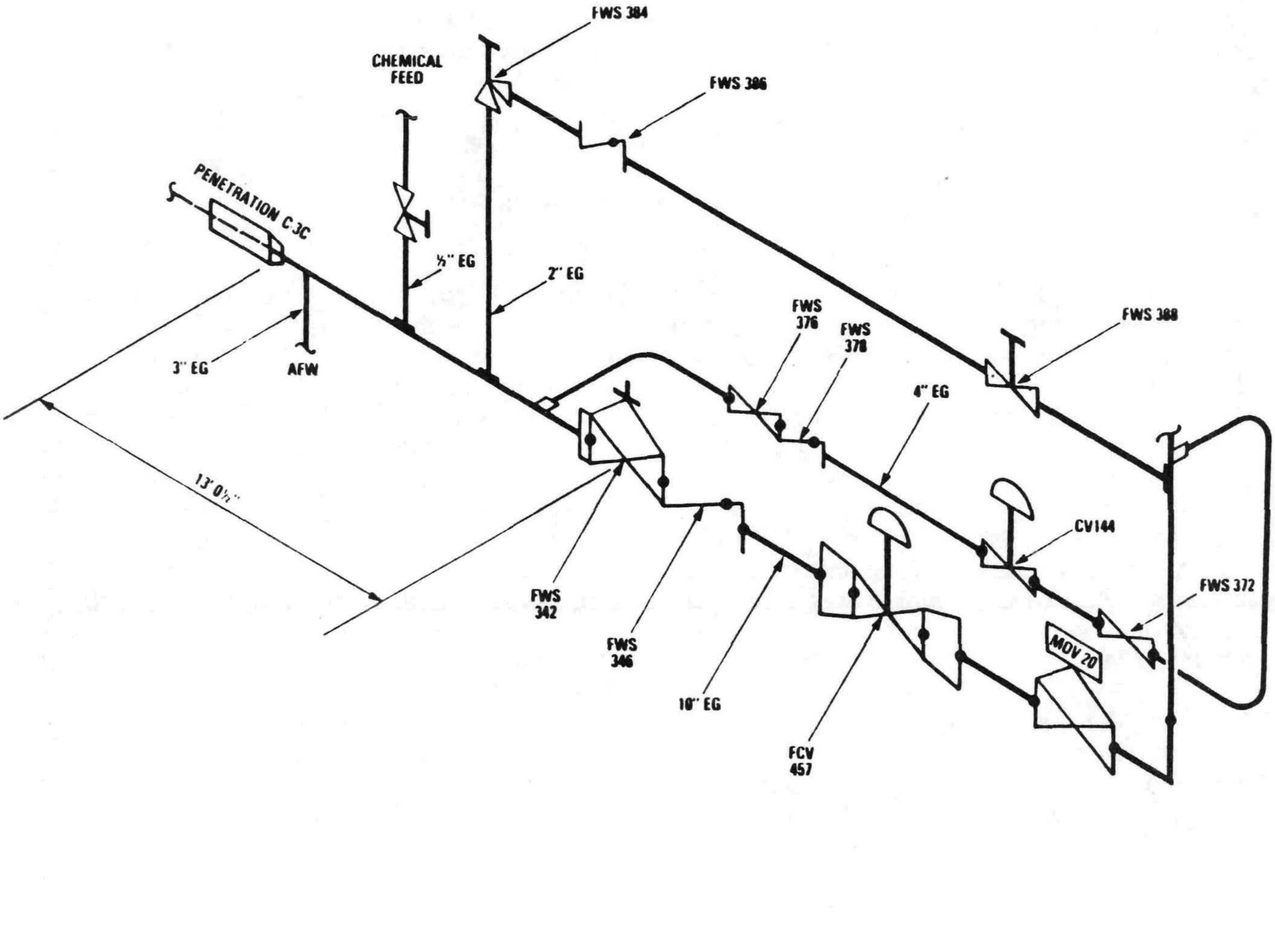


Figure 2.2 LOOP B FEEDWATER CONTROL STATION

The motor–driven AFW pump is a centrifugal type which provides 235 gpm at a design head of 1058 psig. The turbine–driven pump is also a centrifugal type, driven by a single stage turbine which receives steam from the west main steam header and exhausts to the atmosphere. This pump provides 300 gpm at a design head of 1093 psig. The turbine has an automatic startup sequence which removes water from the turbine casing and steam supply lines. Flow from the pump is not available until this sequence is completed.

The auxiliary feedwater flow control valves are preset manually to limit AFW flow to less than 150 gpm per steam generator. This precaution minimizes the potential for steam generator waterhammer when the steam generator is at normal operating pressure.

2.3 SEQUENCE OF EVENTS LEADING TO WATERHAMMER

A detailed timetable is presented in Table 2.1. What follows is a summary of the most significant events.

At 4:51 a.m. on the day of the event, electrical technicians were attempting to isolate a ground fault on a 4.2 kV safety related bus. During their efforts, electrical bus 2C de–energized, tripping the northeast and southeast condensate pumps and the east feedwater pump. Though plant operators were unaware at the time, the 12–inch check valve at the discharge of the east MFW pump was stuck open. Following the loss of power from bus 2C, the west MFW pump (powered by bus 1C) kept operating. Feedwater from this pump was forced back through the failed check valve, overpressurizing the east condensate piping and components. The high pressure feedwater ruptured a tube in the flash evaporator condenser and ballooned the rectangular shell of the flash evaporator, creating a 20–foot long, 2–foot wide fishmouth split along a welded seam. Water and steam covered the east part of the turbine building and activated fire alarms several levels below the turbine deck. 20 seconds later (at 4:52), the reactor was manually tripped, causing the West MFW pump to lose power as well. The steam generators begain to blow down through the hole in the east condensate system.

Following the reactor trip, there was a four minute delay before plant ac power was restored while operators realigned the plant's electrical equipment. The delay was due to failure of the plant's automatic circuit breaker sequencer. Following this delay, ac power was restored through the plant's main transformer and offsite power.

After the reactor trip, the water levels in the steam generators dropped below the setpoint for actuating the auxiliary feedwater system. The turbine–driven pump received a start signal within seconds after the reactor trip. It immediately began its warmup cycle, which lasts about three minutes. The motor–driven pump received an actuation signal as well, but could not start because power was unavailable. Until the turbine–driven pump completed its warmup (at 4:55), there was a complete loss of feedwater to the steam generators.

Once power was restored (at 4:55), procedures called for isolation of the main feedwater lines. Flow from the AFW system was verified to be about 135–150 gpm to each of the steam generators. Isolation of the MFW lines stopped the flow of auxiliary feedwater back through the east condensate system and out through the ruptured flash evaporator. Up until this point, water in the feedwater systems for all three steam generators was draining out.

Table 2.1 Chronological Sequence of Events

<u>Initial Conditions</u>

- Saltwater leaking into the main condenser at 5×10^{-3} gpm
- Unit operating at 60 percent reactor power to facilitate search for condenser leak
- South circulating water pump shut down to allow entry into south condenser water boxes
- Steam generator blowdown ongoing at about 100 gpm per generator to minimize chloride buildup
- Electrical ground troubleshoting in progress; ground determined to be located on auxiliary transformer C supply to 4kV bus 1C
- Bus 1C power supply shifted to 4kV bus 1A, powered from the output of the main generator through auxiliary transformer A
- Auxiliary transformer C remained energized, supplying power to 4kV bus 2C, while personnel inspected electrical equipment
- Fox 3 critical function monitor system recording function disabled because of previous power interruption during ground isolation effort

<u>Transient Initiator</u>

04:51:11 Auxiliary transformer C differential relays detected a phase-to-phase fault current in excess of 1500 amps and actuated trips in associated cricuit breakers to isolate the transformer.

Circuit breakers 4032 and 60 32 opened to isolate auxiliary transformer C from the 200kV switchyard.

Circuit breaker 12C02 opened to isolate auxiliary transformer C from 4kV bus 2C.

<u>Systems Response/Operator Actions</u>

04:51:11+ Bus 2C de-energized, de-energizing the following selected loads:

East feedwater pump
Southeast condensate pump
Northeast condensate pump
East heater drain pump
Vital 120VAC bus 4

	Diesel generator 2 started automatically on loss of 4kV bus 2C, but did not load automatically, per design.
	East feedwater pump discharge check valve failed to seat as the de-energized pump coasted down.
	Running west feedwater pump pressurized the east condensate-feedwater heater train.
	East flash evaporator condenser tubes became overpressured, ruptured and overpressurized the evaporator shell, causing the shell to develop a fishmouth opening approximately 20 feet long and 2 feet wide. The accompanying noise was described as a "muffled howitzer."
04:51:31	Operators manually tripped the reactor in response to loss of vital 120VAC bus 4, as required by procedure, due to wholesale loss of control room instrumentation. The reactor trip initiated a turbine trip.
04:51:32	Operators pushed the unit trip button, opening main transformer output circuit breakers 4012 and 6012, auxiliary transformer A and B output circuit breakers 11A04 and 11B04, and tripping the turbine.
04:51:32+	All in plant power was lost, except for 120VAC vital buses carried by inverters.
	All in plant lighting was lost, except for battery-powered emergency lighting.
	Letdown, steam generator blowdown and the containment sphere mini-purge isolation valves shut on loss of power.
	Diesel generator 1 started automatically on loss of 4kV bus 1C, but did not load automatically, per design.
	Station loss-of-voltage automatic transfer scheme initiated to allow backfeed of offsite power through the main and auxiliary transformers.
	Security access control equipment malfunctioned following automatic transfer to alternate power supply.

Electric and steam-powered auxiliary feedwater pumps received automatic initiation signals on low steam generator level, due to level drop following reactor trip and turbine stop valve closure. The electric-driven pump started later, after electric power was re-stored. The steam turbine-driven pump began a 3 1/2-minute warmup period.

All three steam generator feed regulating valves shut to 5 percent flow position in automatic response to a reactor trip.

As the west feedwater pump stopped, its discharge check valve and the check valve downstream of the regulating valve of the C steam generator failed to seat. At the same time, the discs in each check valve downstream of regulating valves to A and B steam generators settled to the bottom of their respective valve bodies. All three steam generators began to empty their feedwater lines to the east flash evaporator condenser because of the tube rupture.

Operators verified that rod bottom lights energized, indicating the reactor had tripped.

East and west main feedwater pump shaft seal drain trap vents were observed to be blowing excessive steam and water.

The fire watch in the 4kV switchgear room received a fire alarm from the lube oil reservoir area, observed steam in the area and called station emergency services.

East condensate-feedwater train condensate relief was observed to be blowing steam.

Main feedwater pump suction and discharge temperatures increased to approximately 400°F.

Operators responded to a spurious annunciation and sequencer light indication of initiation of the safety injection system, but determined that plant parameters did not require operation of the system and that the system had, in fact, not actuated.

Station emergency services dispatched a fire truck to Unit 1.

Operators observed that the 18kV system isolation light actuated, indicating that the first phase of loss of voltage auto transfer scheme had been completed.

	Operators attempted to reset the unit trip lockup bus to enable backfeed of power from the switchyard, but the reset failed, apparently due to the timing of the attempt before the main generator no-load motor-operated disconnect was fully opened. The operator did not verify that the reset was effective.
	Operators found security access controls were not responsive and utilized planned procedures, personnel, and hardware to compensate.
04:55+	Steam turbine-driven auxiliary feedwater pump completed its warmup cycle and began to delivery approximately 130 pgm AFW flow (indicated flow was about 110 gpm/SG) at outside ambient temperature to main feedwater lines just downstream of the three feedwater control stations. Reverse flow in the main feedwater line carried AFW to the condensate system.
	Operators decided that the station loss of voltage automatic transfer scheme had failed and attempted to complete the sequence from the control room.
	Operators discussed energizing buses using the running but unloaded diesel generators. Operators decided to energize buses using the preferred offsite power source.
	The first attempt to close 200kV switchyard circuit breaker 4012 failed because an operator did not push the synchronizing check-bypass pushbutton.
04:55:13	The second attempt to close 4012 succeeded when the operator correctly depressed the pushbutton, but it immediately tripped free because the unit trip lockup bus had not been reset.
04:55:15	The third attempt to close 4012 had the same results as the second attempt.
	An operator reset the unit trip lockup bus.
	The first attempt to close 220kV switchyard circuit breaker 6012 failed because an operator had again not depressed the synchronizing check-bypass pushbutton.
04:55:24+	The second attempt to close 6012 succeeded, backfeeding power from the 220kV switchyard, which had remained energized, to auxiliary transformers A and B.

Table 2.1 Chronological Sequence of Events (Continued)

	Operators closed the feeder circuit breaker from auxiliary transformer A to 4kV bus 1A, re-energizing 4kV bus 1 A and 1C. (The tie breaker between bus 1A and 1C had never been opened.)
	Operators closed the feeder circuit breaker from auxiliary transformer B to 4kV bus 1B and from bus 1B to 2C. Operators subsequently completed re-energization of the station by powering the remaining de-energized 480VAC buses.
	The electric-powered auxiliary feedwater pump started with a 20-second delay upon regaining power, due to the continued presence of a steam generator low level signal, and increased AFW flow to approximately 155 gpm per steam generator (indicated flow as about 135 gpm/SG).
	Letdown automatically reinitiated on return of power, but the charging pumps remained tripped.
	Atmospheric steam dumps actuated on return of power, but operators shifted steam dump operations to automatic pressure control, thereby securing steam dumps.
	Operators shut feedwater isolation valves MOV-20, 21 and 22 and feedwater regulating valves FCV 456, 457 and 458, as required by procedure, unknowingly stopping further voiding of steam generator feedwater lines and starting the refilling process at a rate of approximately 155 pgm per steam generator.
	The Supervisor of Coordination reset radiation monitor alarms that were received because of loss of power. Resetting the monitor for steam generator blowdown re-initiated blowdown for each steam generator at about 100 gpm.
	Letdown isolated automatically on low pressurizer level.
	Operators checked pressurizer level and pressure as required by procedure, found level and pressure were low and decreasing, at about 5 percent and 1880 psig, respectively, and became concerned that plant cooldown could be excessive or cause safety injection.
04:58	Operators started the south charging pump to raise pressurizer level.
04:59	The north charging pump started automatically on low charging header pressure with one charging pump running.

Table 2.1 Chronological Sequence of Events (Continued)

05:00	The suction of both charging pumps shifted automatically between VCT and RWST and back as the level cycled through VCT low level set points.
	Operators verify proper operation of AFW pumps.
	Operators started reactor coolant pump b to provide a source for pressurizer sprays for pressure control.
05:02	Operators terminated AFW flow to the steam generators to minimize RCS cooldown; then subsequently resumed AFW flow to all steam generators at a rate of about 40 gpm per generator (indicated flow was about 25 gpm/SG).
	The STA arrived in the control room.
	A plant equipment operator was dispatched to manually close main steam block valves to reduce plant cooldown.
05:07	A loud "bang" was heard. The nuclear plant equipment operator, sent to shut the main steam block valves, heard a water hammer and observed steam on the turbine building mezzanine. The operator left the main steam valves.
05:08	Circuit breaker 4012 was closed by an operator utilizing the synchronizing check–bypass pushbutton.
05:09	The reactor cooling pump B thrust bearing high temperature alarm annunciated.
05:10	The control room received a report of a steam leak on the feedwater mezzanine from a dripping wet operator, who had just returned from that location.
	Letdown valves opened after pressurizer level rose above 10 percent.
05:12	Operators shut the turbine plant cooling water (TBCW) supply valve for containment sphere air coolers and started at TBCW pump. An operator was dispatched to re–established TBCW flow to containment sphere air coolers.
05:17	Charging pump suction was shifted to the RWST to start boration for cold shutdown.

Table 2.1 Chronological Sequence of Events (Continued)

05:20	Operators reset the safeguards sequencers and secured the unloaded diesel generators.
	Operators secured the lube oil reservoir foam system and ire pump, after confirming that the system should not have actuated.
05:24	Operators started reactor coolant pump A.
05:27	Operators started reactor coolant pump C.
	The wide range level indication dropped off-scale low in all three steam generators.
05:28	Operators stopped reactor coolant pump B.
	Operators decided to establish rapid controlled cooldown of RCS at about 100°F/hr to stop the assumed steam leak.
	Operators increased flow to steam generator A and C from about 40 gpm to about 70 gpm each. AFW flow to the B steam generator was maintained at about 40 gpm.
05:30	Blowdown from steam generators was secured by reducing the setpoint on the radiation monitor.
	Wide range water level indication returned on-scale in A and C steam generators.
	Operators commenced periodic air sampling for radioactivity in the vicinity of the steam leak. The highest sample reported showed 5 x 10^{-10} uCi/cc.
	Personnel wearing steam suits made two attempts to identify and secure the source of the steam leak.
05:45	The turbine generator was placed on a turning gear.
	Operators shut steam generator blowdown micro-valves.
	HQDO called SONGS-1 on the ENS to check plant status and establish an open line. The shift superintendent was asked to call back once he could get someone assigned to maintain an open line.
05:46	Safety injection was blocked.

Table 2.1 Chronological Sequence of Events (Continued)

unknown	The north charging pump was secured. Sandbags were placed at the entrance to the chemical feed room to prevent water from flowing across the floor into the electrical switchgear rooms.
05:57	Operators stopped boration using RWST.
05:58	Operators noted containment sphere pressure was slightly positive; found that containment sphere mini-purge valve CV-10 had not been re-opened after the radiation monitors were reset following restoration of power; and opened CV-10, allowing containment sphere pressure to return to its normal, slightly negative condition.
	HQDO succeeded in establishing an open line between the site emergency coordinator, the NRC regional duty officer and the headquarters Incident Response Center. The line would remain open until released by NRC.
	The HQDO notified FEMA of the declaration of an Alert.
06:15	Operators, unable to start the circulating water pumps due to high condenser temperature and steam on the water boxes, aligned saltwater cooling to the turbine plant cooling water heat exchanger.
06:30	Operators started emergency boration for cold shutdown.
07:00	Operators secured emergency boration.
07:44	A monitoring team dispatched to measure potential offsite radioactivity determined downwind site boundary radiation levels to be less than 0.1 mrem/hr.
07:47	Operators started the second emergency boration to assure 5 percent shutdown in mode 5.
07:55	Emergency boration was secured.
08:00	Entered Mode 4; operators still believed there was a steam leak.
08:35	Operators secured the turbine-driven auxiliary feedwater pump due to low steam pressure.
08:36	Operators aligned screen wash pumps to supply cooling for the turbine plant cooling water heat exchangers.

Table 2.1 Chronological Sequence of Events (Continued)

08:37	Operators aligned salt water cooling pumps to provide maximum component cooling water heat exchanger cooling.
09:00	Operators started a third component cooling water pump in preparation for initiating RHR.
09:10	Operators attempted to open RHR suction valves, but pressure interlock had not yet cleared, although RCS pressure was well below 400 psig.
	Air sample from the chemistry sample room determined that noble gas activity was 1.87 times the maximum permissible level.
09:12	Containment sphere entry was made to isolate the hot leg recirculation flow path by shutting valve RHR-004.
09:18	Operators overrode the high pressure interlock and opened MOV-813 and 834.
09:20	Operators stopped vacuum pumps.
09:30	Operators shut RHR-004.
09:35	Operators started the West RHR pump.
09:38	Operators started the East RHR pump.
10:00	Shift turnover began and continued sequentially until all positions were briefed and properly relieved.
10:45	Feedwater leakage was manually isolated.
11:15	A work order was issued to repair the security system affected by moisture from the leak.
13:20	Steam generator samples showed activity in A and C less than the threshold of detectability; activity in B was 2.87×10^{-5} uCi/ml.
14:06	Operators restarted the 480V room air conditioner.
14:10	Operators isolated a dc ground on control power to FCV-456 and 457.
14:36	Operators commenced RCS degassing.
15:08	The plant entered Mode 5.

Table 2.1 Chronological Sequence of Events (Concluded)

NOVEMBER 22, 1985

01:00	Operators entered the containment sphere and identified damaged pipe supports and insulation on the B steam generator feedwater line.
16:41	Operators secured filling the AFW tank from Unit 2 and 3.
17:32	Operators secured filling the AFW tank from Unit 2 and 3.
21:40	Operators manually closed the main steam isolation valves.
22:45	Operators transferred water from A to B steam generator, using the blowdown lines.

At 5:02, a plant equipment operator was dispatched to manually close the main steam block valves to reduce the rate of plant cooldown. At 5:07 a loud bang was heard in the control room. The plant equipment operator heard the waterhammer, felt a concussion wave and was enveloped by steam on the turbine building mezzanine

Following these events, operators successfully cooled the plant down and brought it to a stable cold shutdown. Teams were sent out to examine the piping. Over the next two days, the complete extent of the waterhammer damage was discovered.

2.4 DESCRIPTION OF DAMAGE

PIPING AND PIPING SUPPORT DAMAGE

The loop B feedwater pipe was severely damaged in two locations. The northeast elbow (see Figure 2.1) was dented on the inside and slightly bulged, indicating plastic yielding. An axial crack roughly 80 inches long was found near support H00K, as shown in Figure 2.3. The crack penetrates 25% of the pipe wall on average, extending to 30% at its deepest point. The entire 10–inch line was displaced up to several feet both vertically and horizontally, as shown in Figures 2.4 and 2.5. (These Figures are the results of detailed post–event surveys.)

Damage to piping supports along this line was also severe in some instances. The locations of loop B piping supports inside containment are illustrated in Figure 2.1. Table 2.2 describes some of the damage, and Figures 2.6 through 2.13 are photographs of the various support stations taken soon after the event. Figure 2.14 shows the loop B containment penetration viewed from outside contaiment. Note the concrete surounding the penetration is cracked due to excessive force from the pipe.

LOOP B FLOW CONTROL STATION DAMAGE

The loop B flow control station is located outside the containment building. Several valves were damaged by the waterhammer, including check valve FWS–378 and flow control valve FCV–457 (see Figure 2.2).

Check valve FWS–378 was intact and operational during the waterhammer, and was subjected to high waterhammer loads. As a result, its bonnet studs yielded and the gasket was forced outwards against the studs, as illustrated in Figure 2.15. The flow control valve (FCV–457) incurred damage to the valve actuator yoke, shown in Figure 2.16. Disassembly revealed a bent valve stem.

AUXILIARY FEEDWATER SYSTEM PIPING DAMAGE

Evidence of pipe motion in the AFW system was observed up to several hundred feet upstream of the junction with feedwater loop B (see Figure 2.17). Though this indicates that waterhammer loads were imposed on the AFW loop B piping, there were no indications of piping damage.

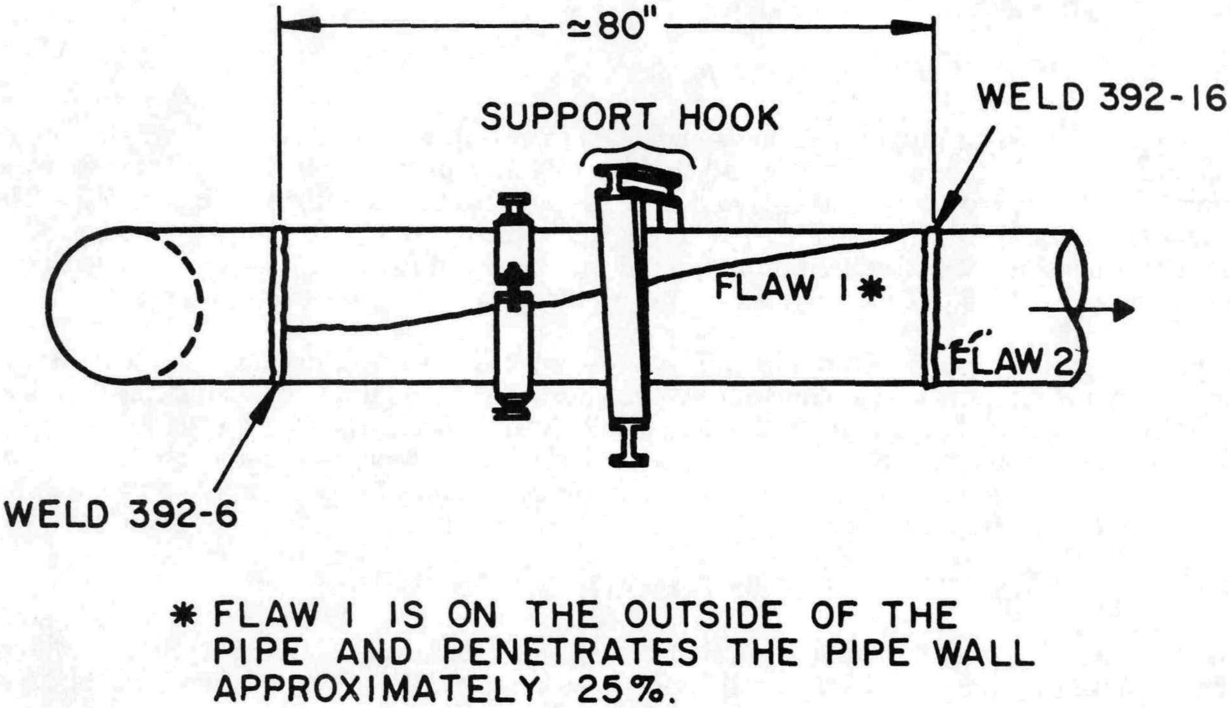


Figure 2.3 AXIAL CRACK DUE TO WATERHAMMER

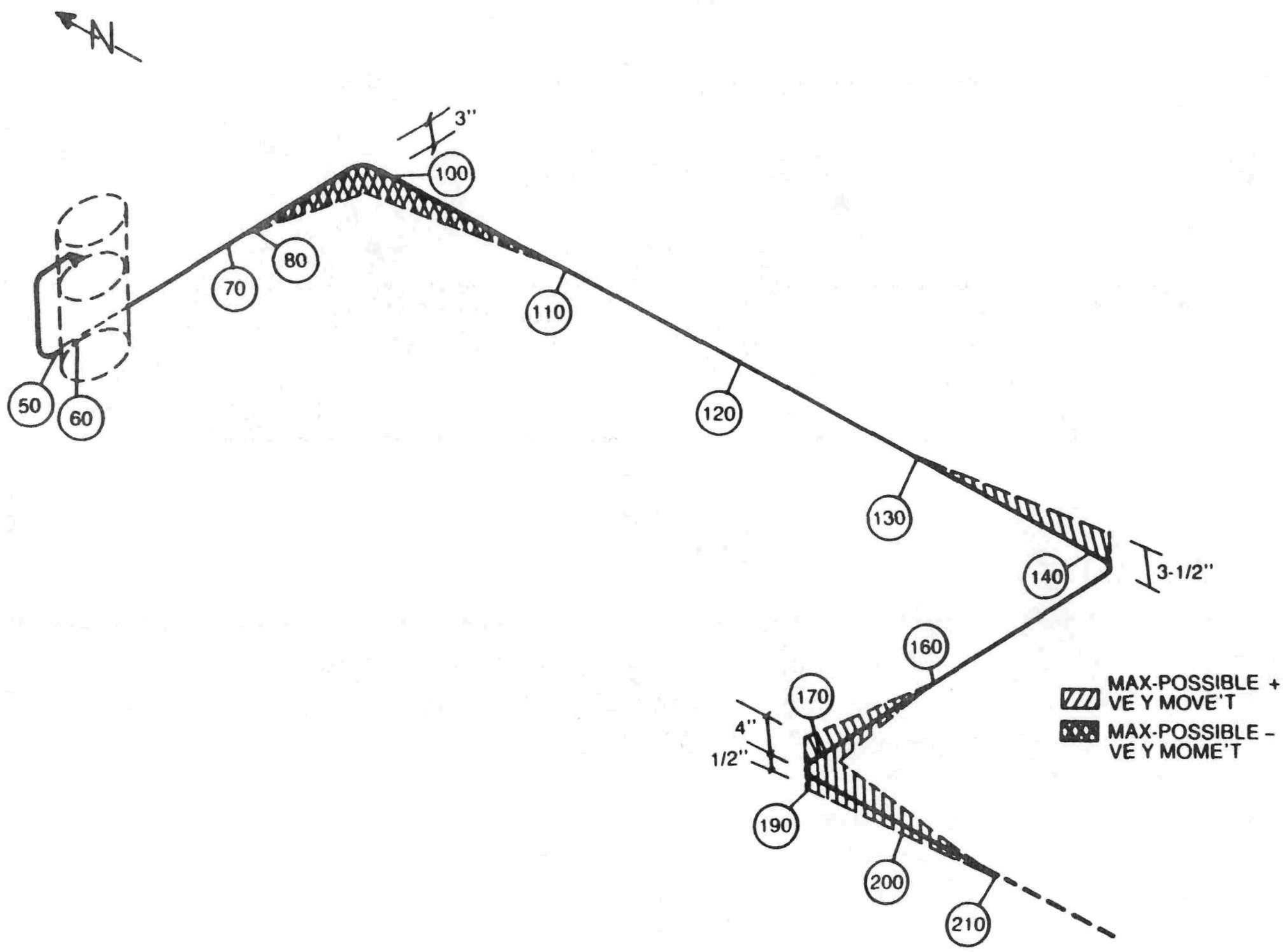


Figure 2.4 VERTICAL DISPLACEMENT OF FEEDWATER LOOP B

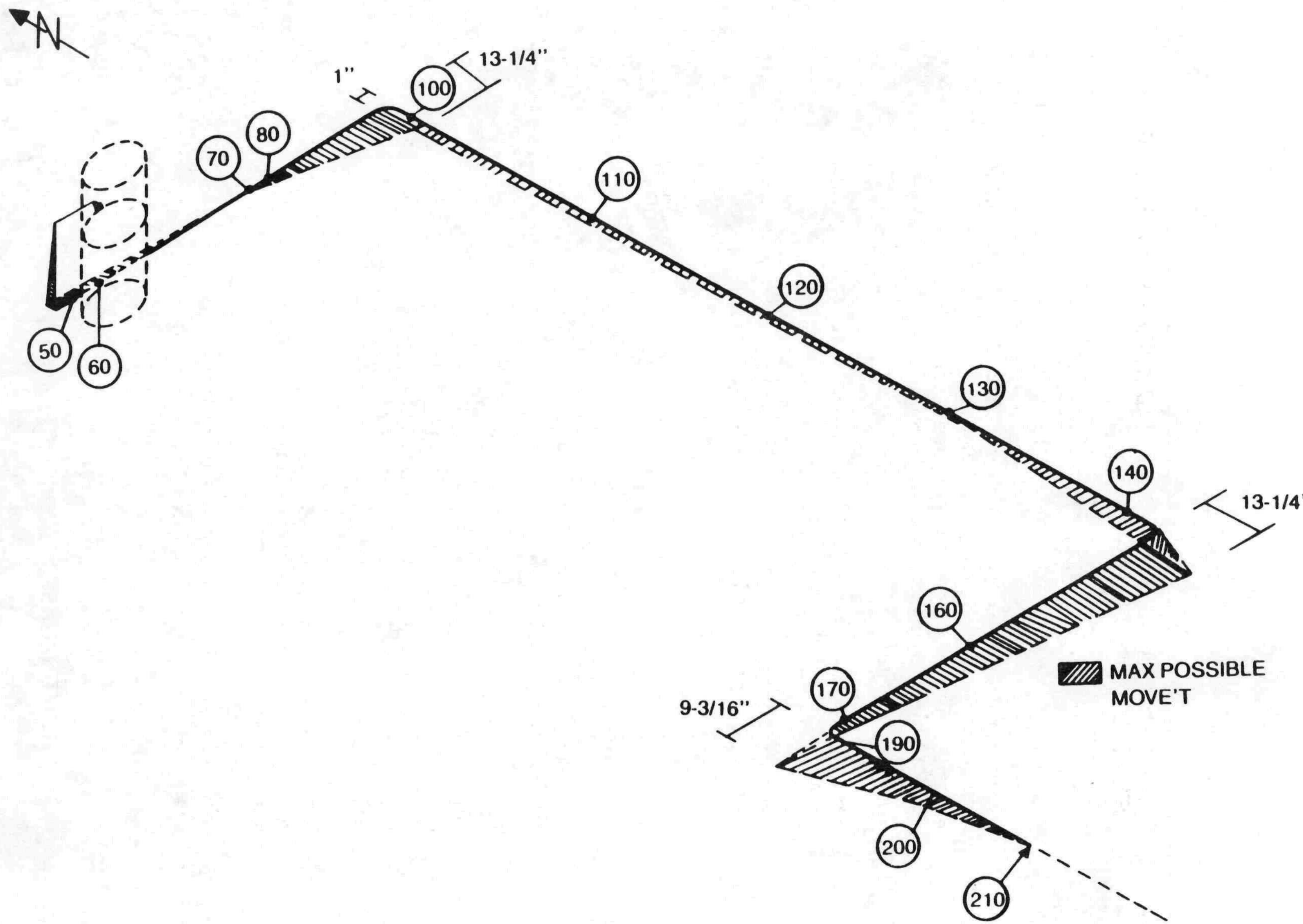


Figure 2.5 HORIZONTAL DISPLACEMENT OF FEEDWATER LOOP B

Table 2.2. DESCRIPTION AND CORRESPONDING ILLUSTRATIONS OF TYPICAL FEEDWATER PIPE DAMAGE		
Figure	Description of Component, Damage, Motion, Etc.	Support Location(s)*
2.6	View of pipe (looking south) showing movementof approximately 12 inches, slippage of vertical support pads off channel beam structures and downward drop of FW pipe.	H00G
2.7	View of support H00G looking in opposite direction from Figure 2.6.	H00G
2.8	View of horizontal and vertical support pads displaced southward approximately 12 inches.	H00H
2.9, 2.10, 2.11	A series of photos illustrating damage incurred at the support structure down-stream of the southeast elbow. The damage incurred by the structure clearly illustrates the magnitude of pipe motion which occurred during the waterhammer pulse	H00K
2.12	Permanent set (i.e., bend) in FW pipe. View at elbow from support H00K and looking west toward support H00L. Pipe has been bent laterally south from support H00L to SE corner elbow.	at elbow near sup-ports H00K and H00L
2.13	View showing lateral movement (westward) of pipe which resulted in sheared vertical support structure	H00L

*See Figure 2.1 for support locations and identification

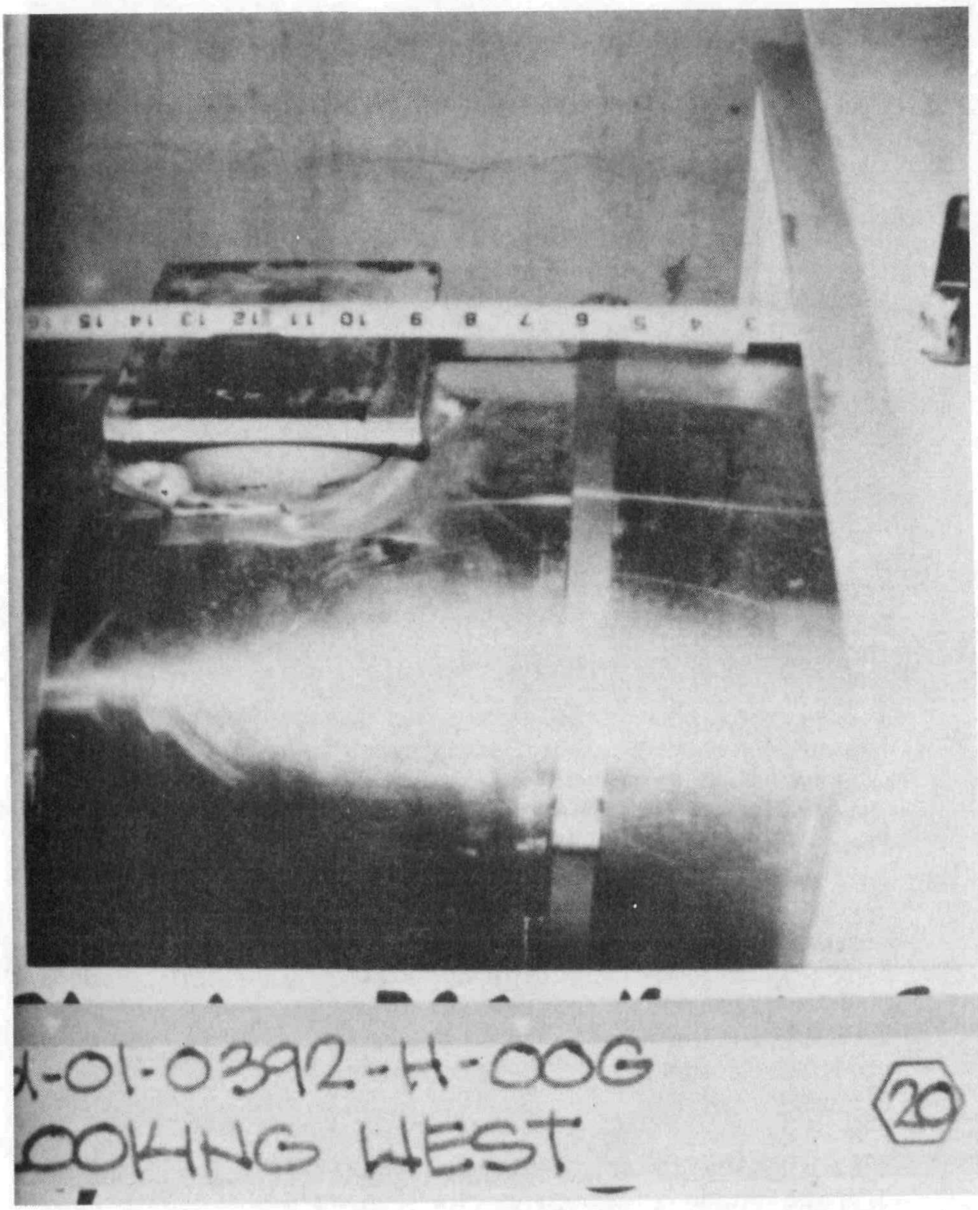


Figure 2.6 SUPPORT H00G

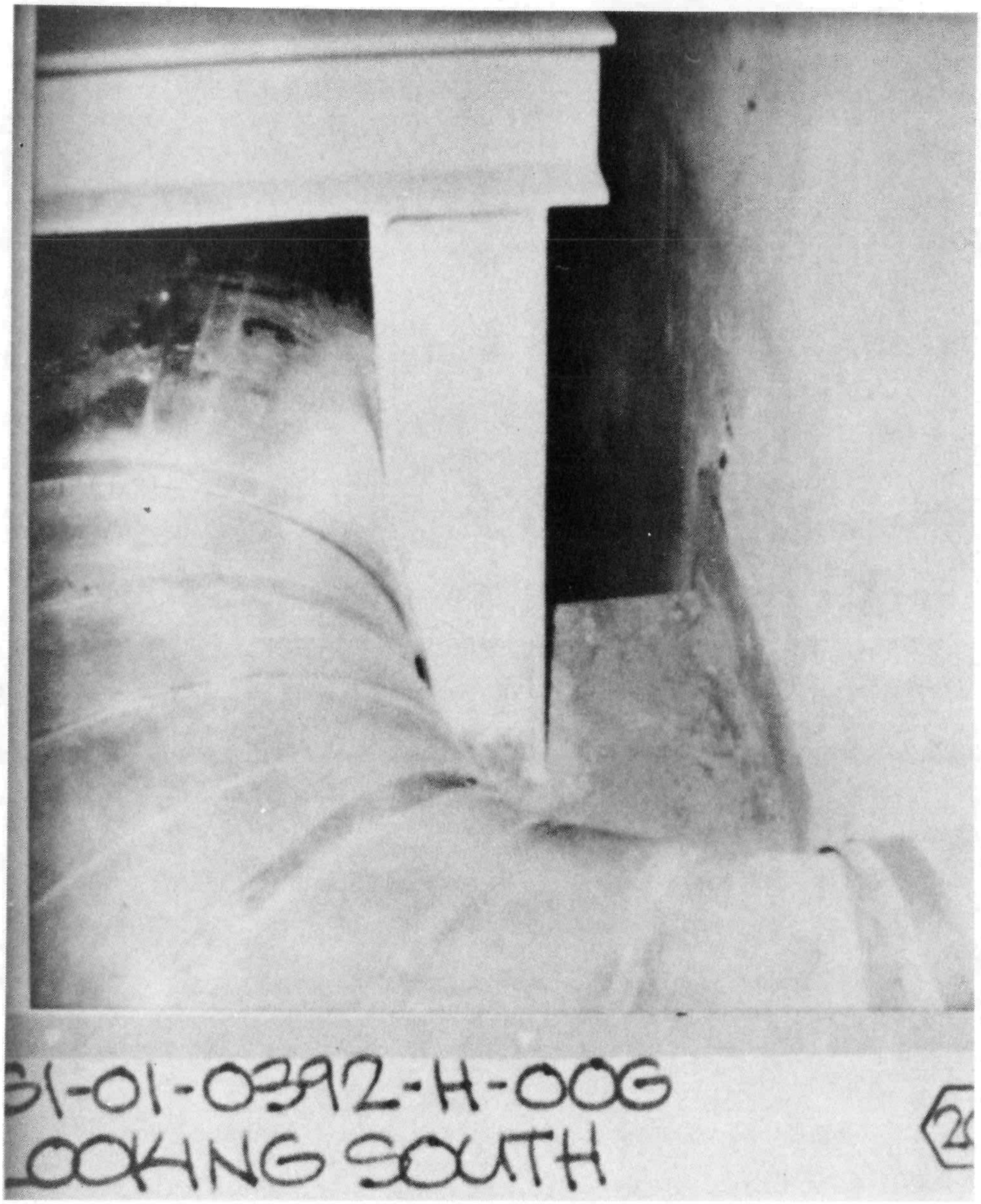


Figure 2.7 SUPPORT H006

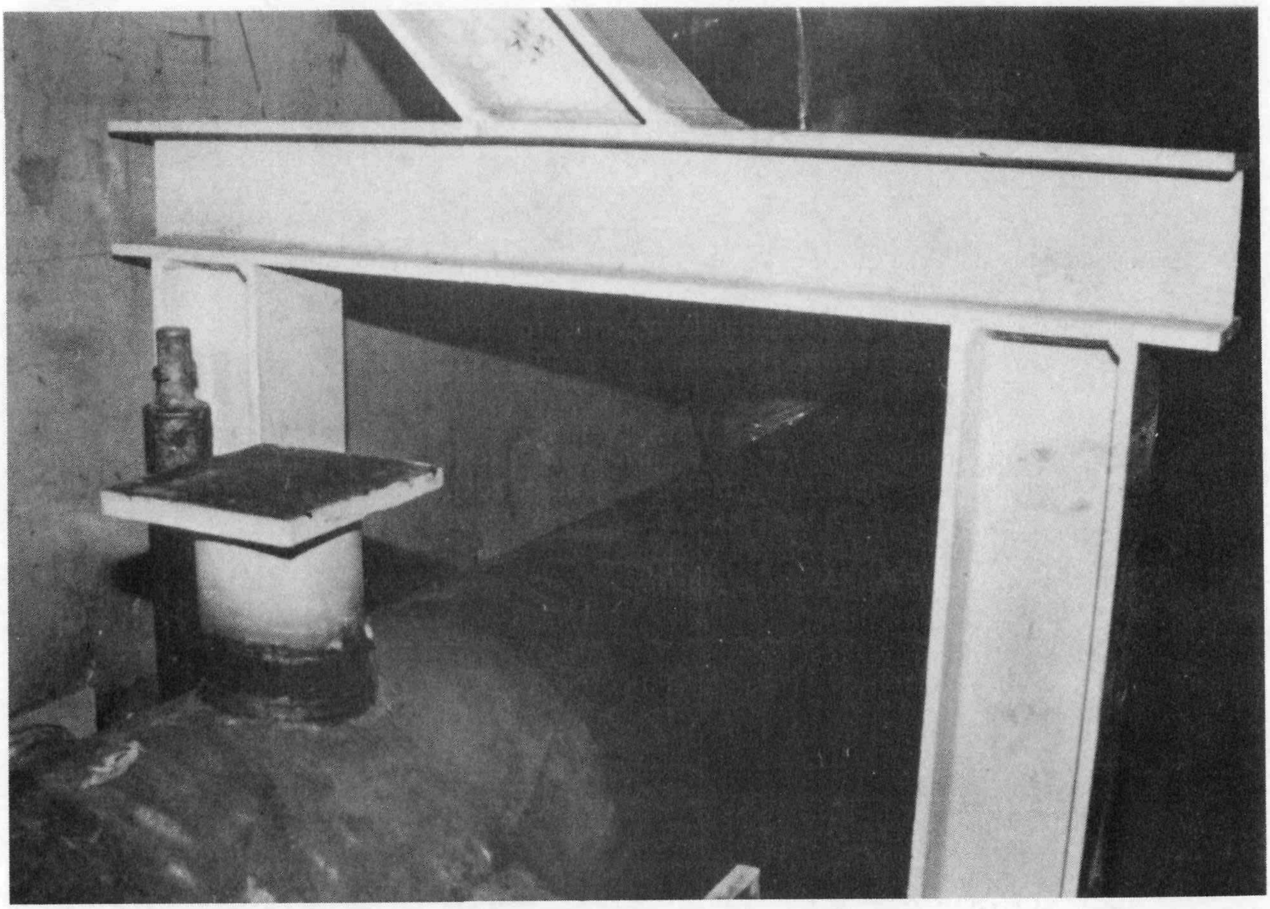


Figure 2.8 SUPPORT HOOH

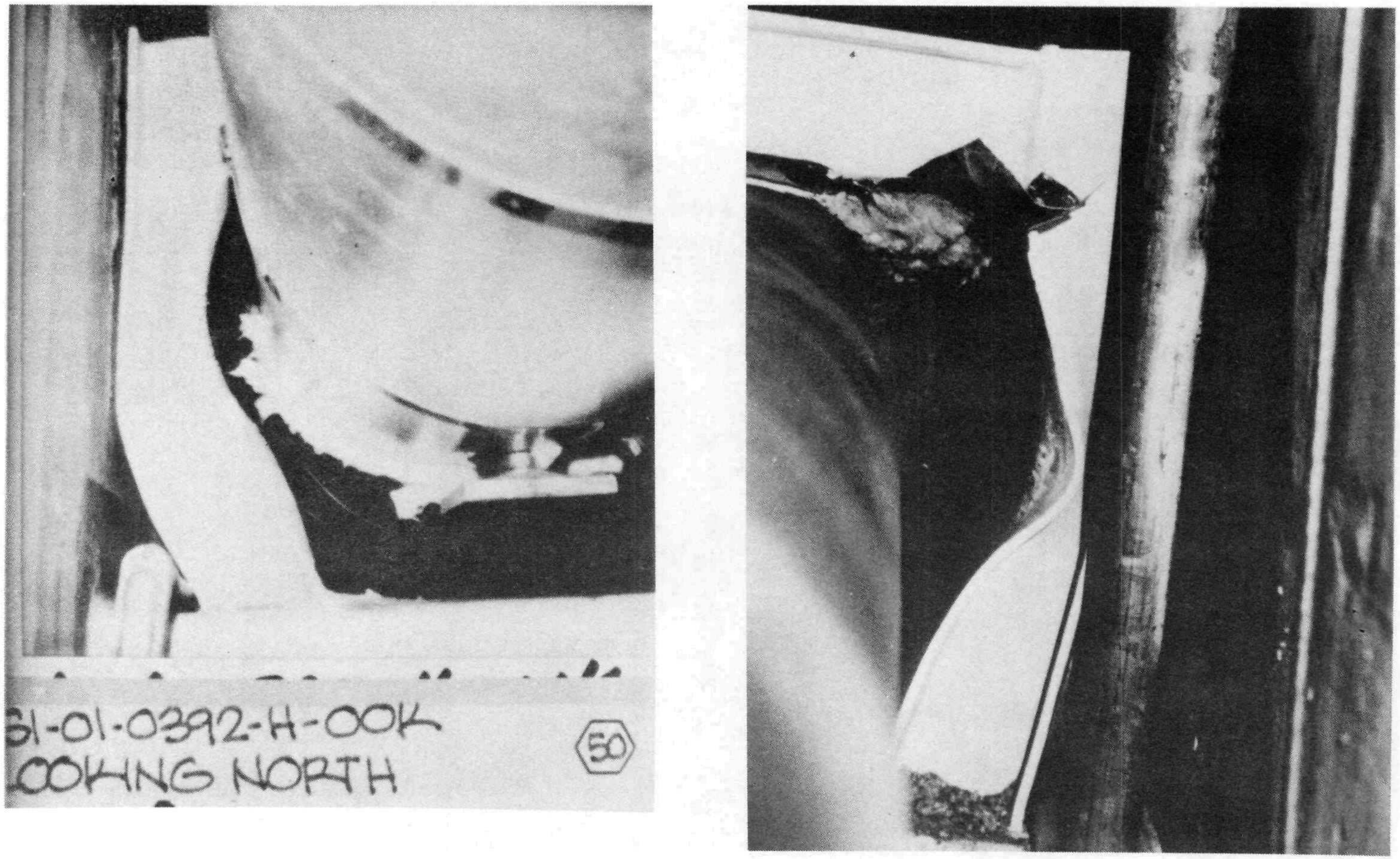
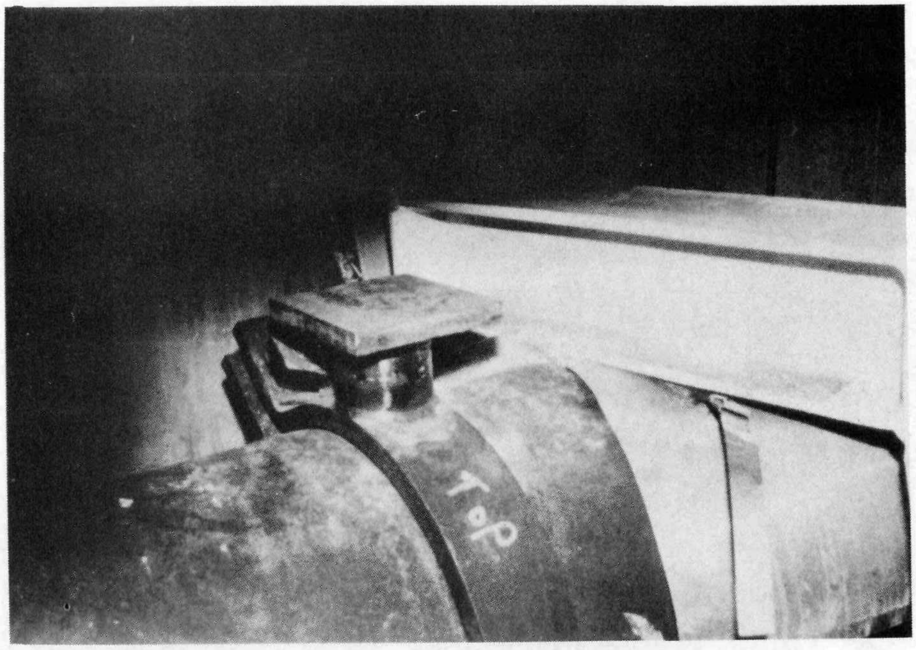


Figure 2.9 SUPPORT HOOK



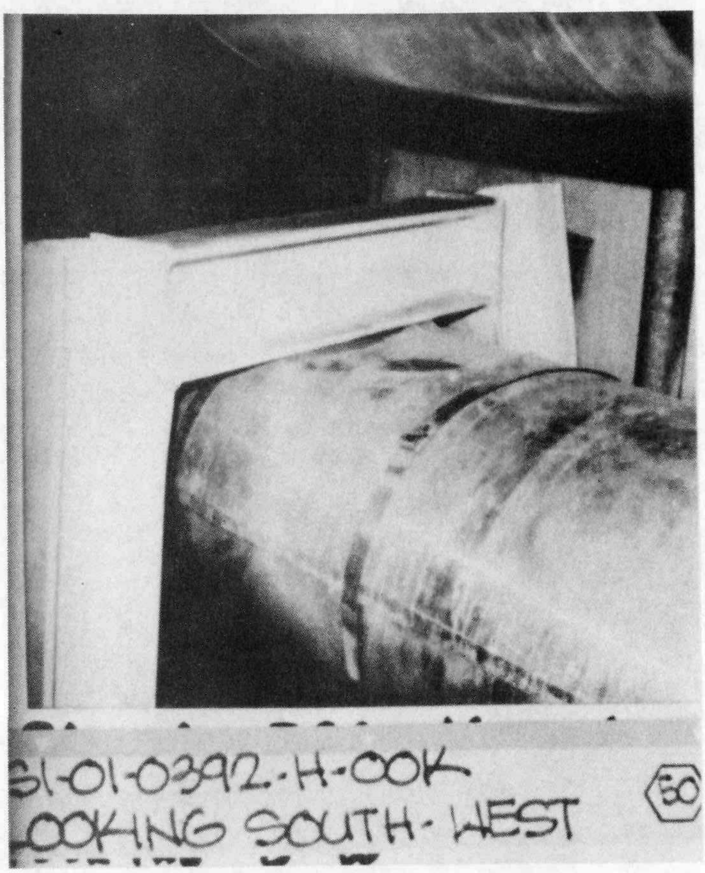


Figure 2.10 SUPPORT HOOK

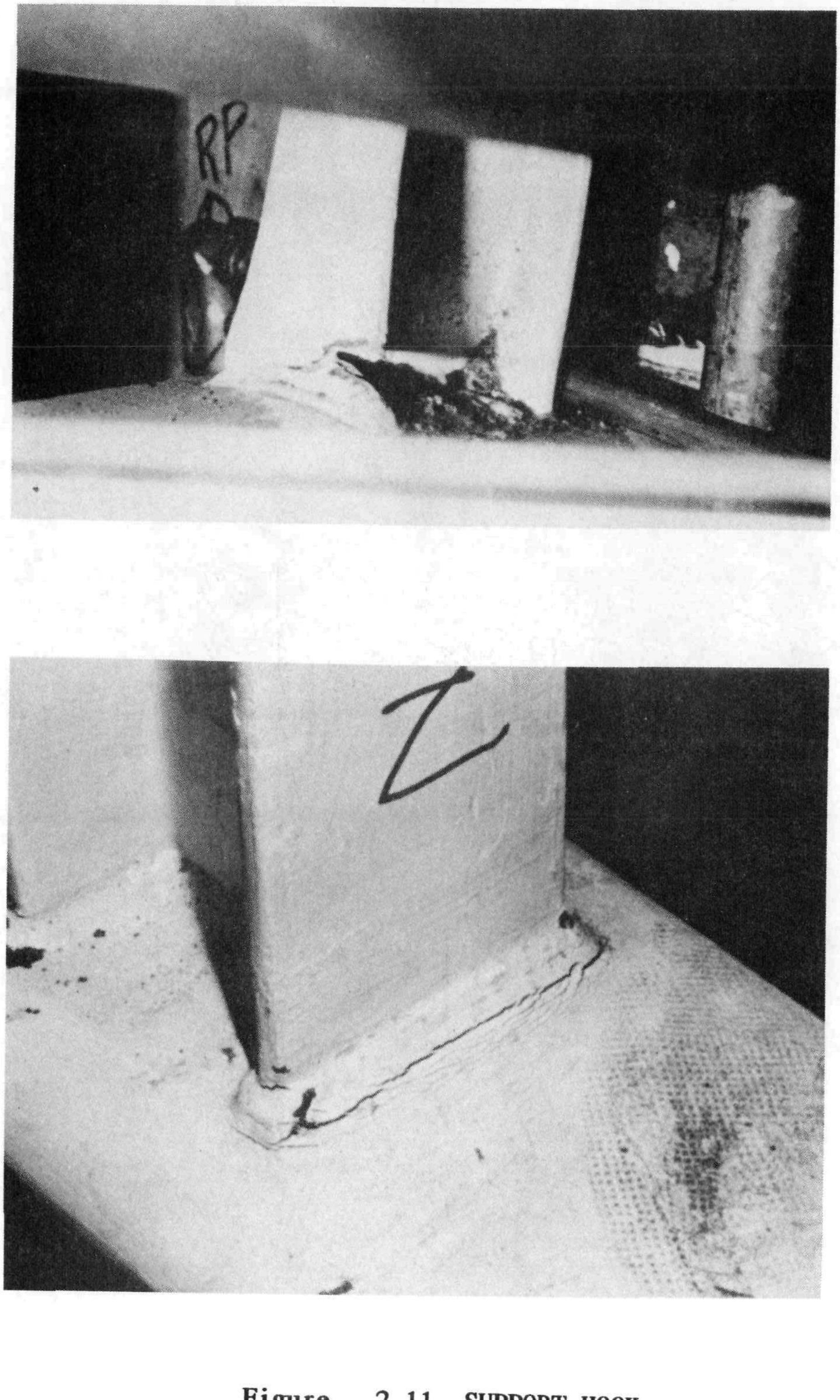


Figure 2.11 SUPPORT HOOK

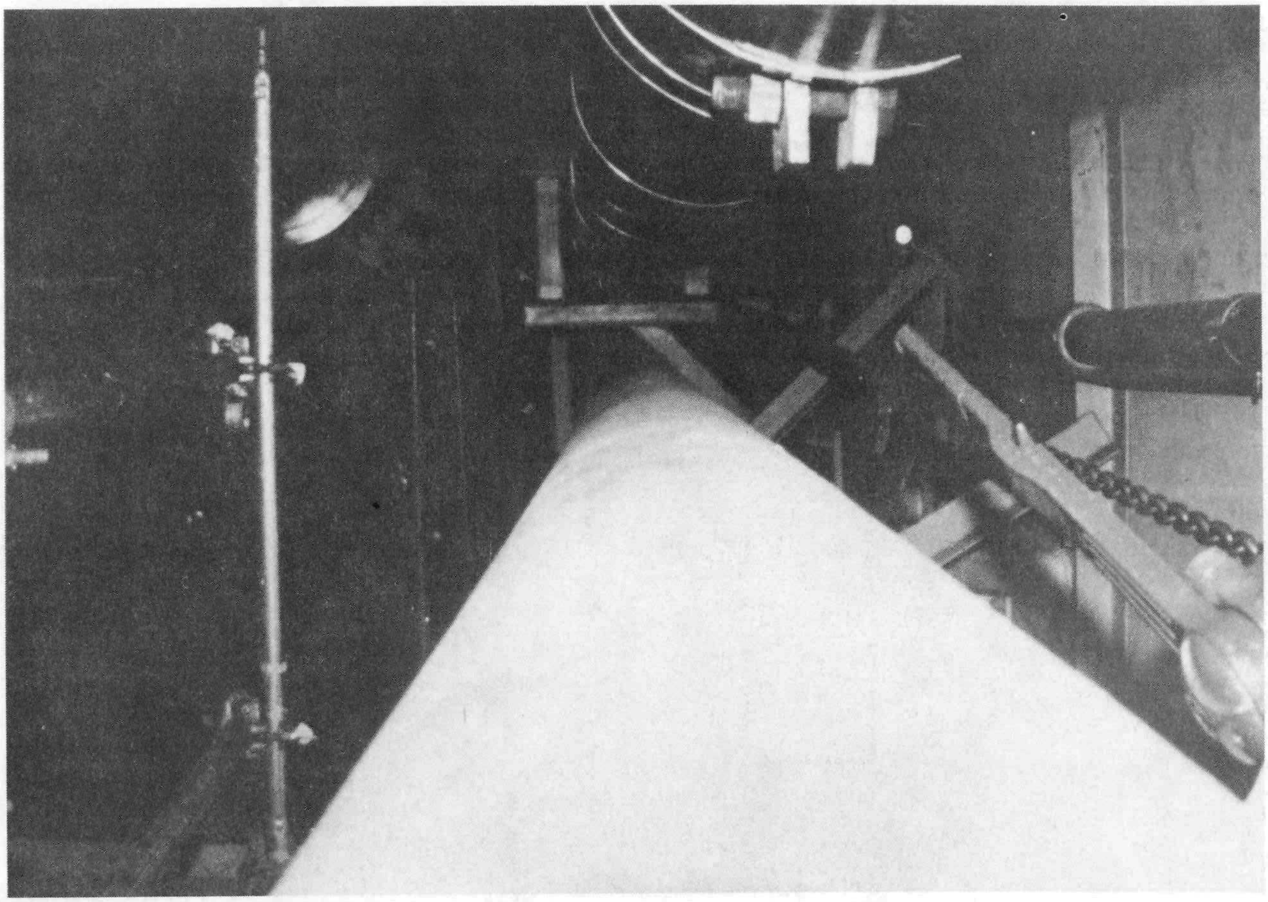


Figure 2.12 VIEW FROM HOOK TO HOOL

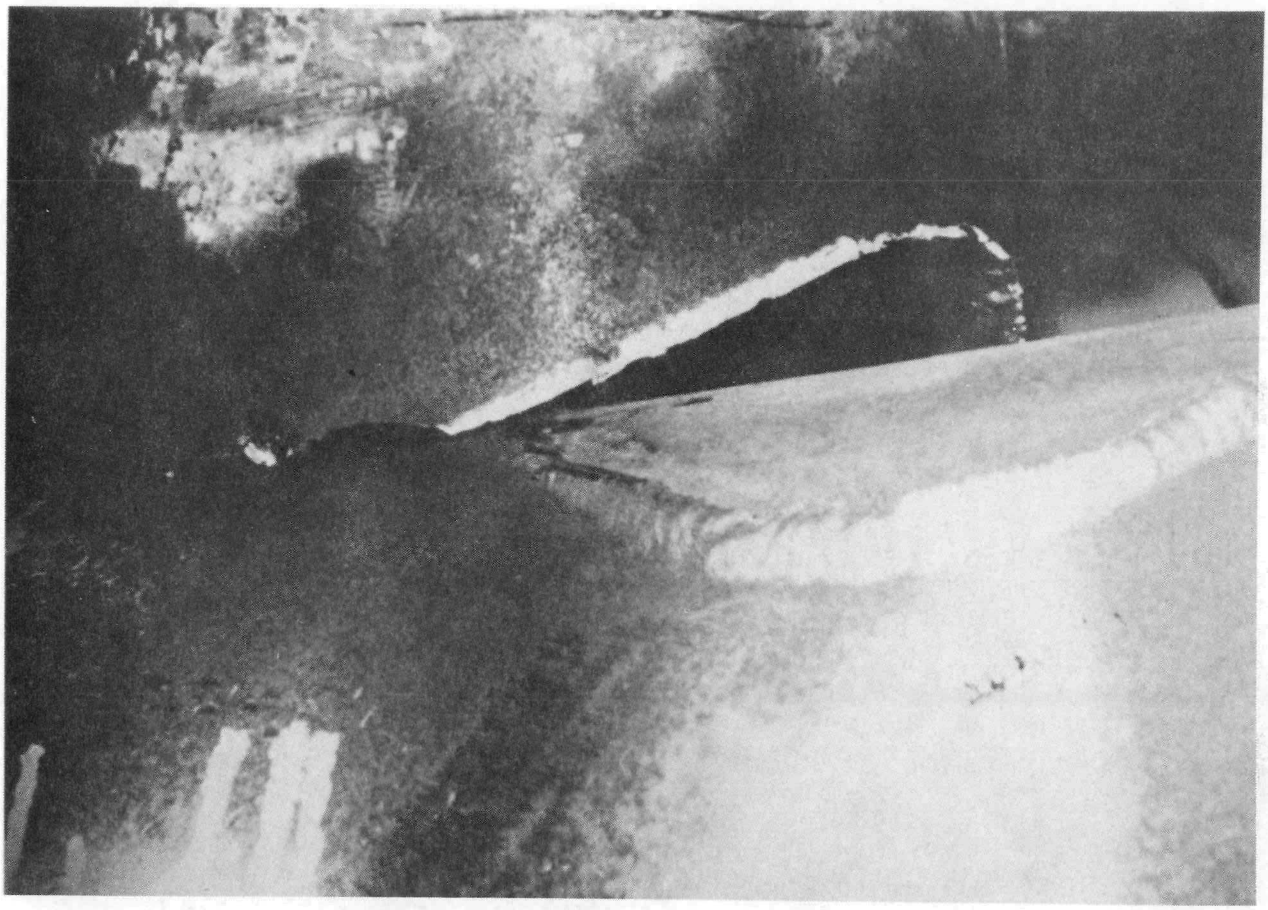


Figure 2.13 SUPPORT HOOL

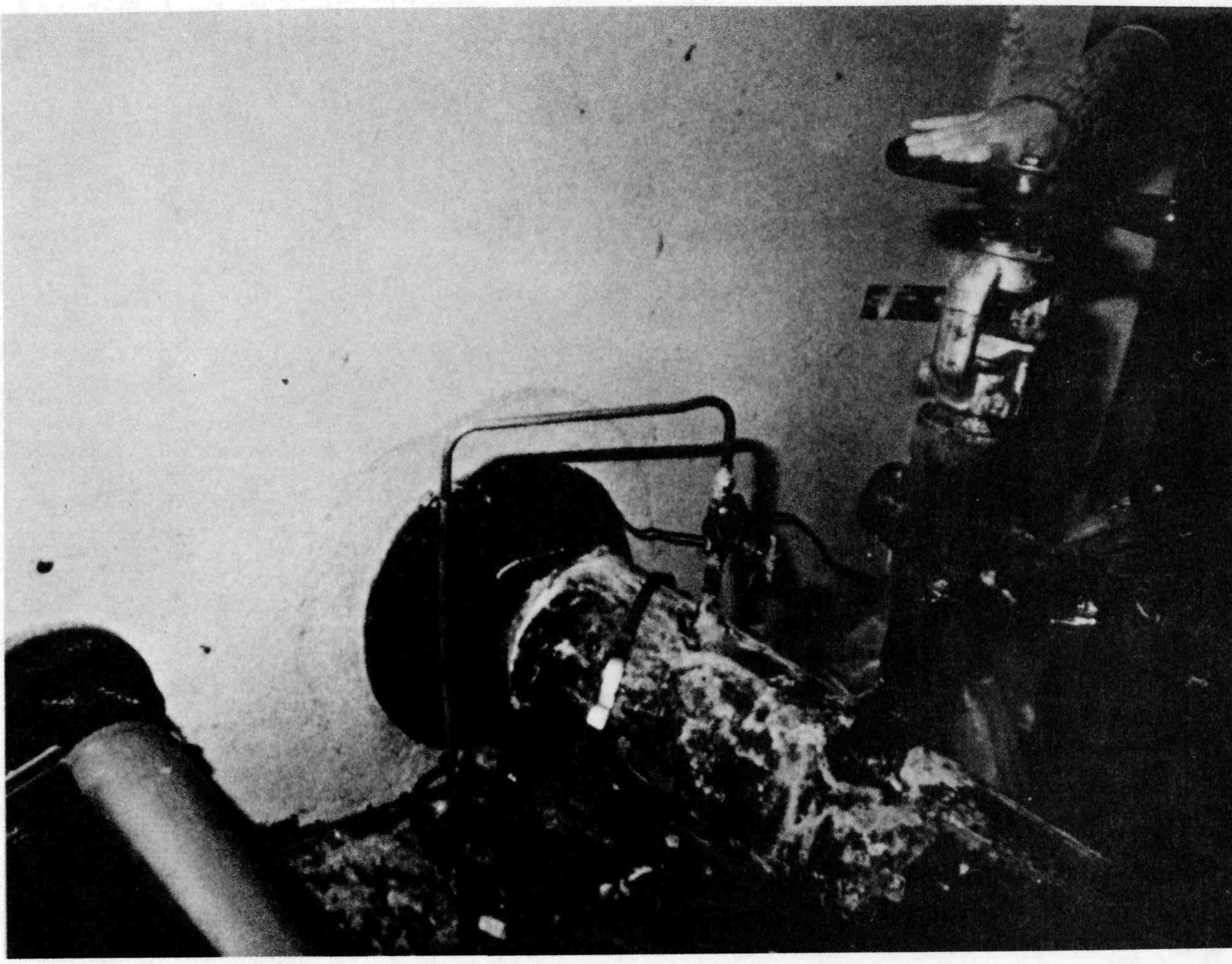


Figure 2.14 LOOP B CONTAINMENT PENETRATION

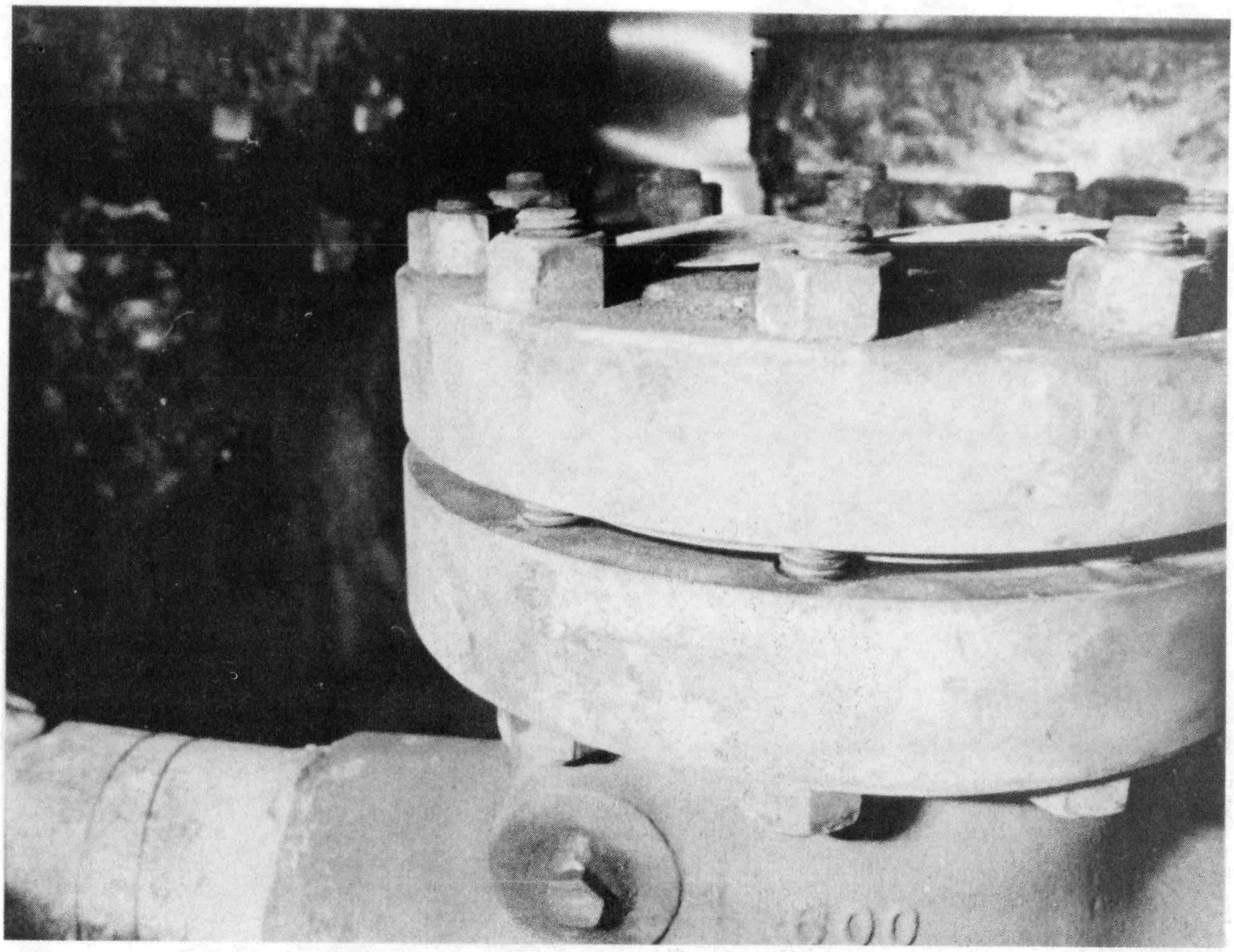


Figure 2.15 BONNET OF CHECK VALVE FWS-378

Figure 2.16 DAMAGE TO YOKE OF FLOW CONTROL VALVE FCV-457

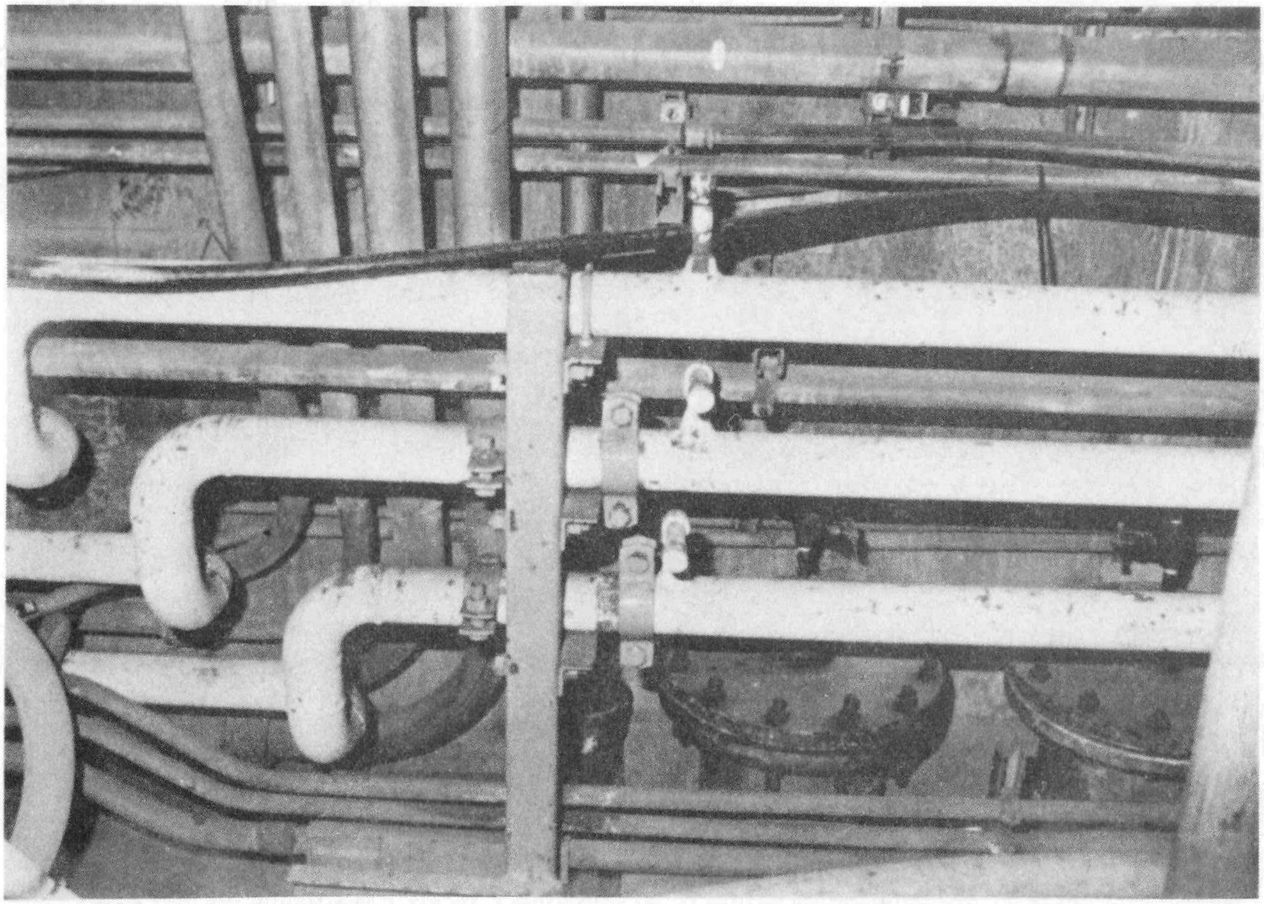


Figure 2.17 INDICATIONS OF MOTION IN B AFW LINE

VALVE MALFUNCTIONS AND DAMAGE

During the post–waterhammer investigation, five failed check valves were discovered. The nature of the failures indicated that they were not caused by the waterhammer, and in fact were eventually identified as an underlying cause of the event.

All of the failed check valves were of the "swing" type, as illustrated in the top portion of Figure 2.18. The valve consists of a closure disk mounted on a hinge internal to the valve assembly. The disk is free to swivel about the hinge, permitting water to flow from left to right in the Figure. However, the disk will close and prevent flow from right to left. A valve bonnet is provided to allow access to the disk for inspection and maintenance.

In two of the failed check valves (FWS–345 and 346) the disk was actually separated from the hinge arm and found lying in the bottom of the pipe. The three other valves (FWS–398, 438 and 439) were found stuck partially open due to partial rotation of the disks. The anti–rotation lugs were lodged under the hinge arm and prevented the disk from fully closing, as illustrated in the bottom half of Figure 2.18.

In all cases, there were indications that the check valve had been damaged over a period of time prior to the waterhammer event. For example, various wear and scratch marks found on the FWS–345 and 346 valve internals shown in Figure 2.19, indicate continued operation with loosened or lost disk nuts. Wear on the anti–rotation lugs in the other three check valves indicates that they had been subject to repeated impact over a long period of time. This evidence indicates that the five failed check valves were already inoperative when the waterhammer occurred.

2.5 WATERHAMMER DIAGNOSIS

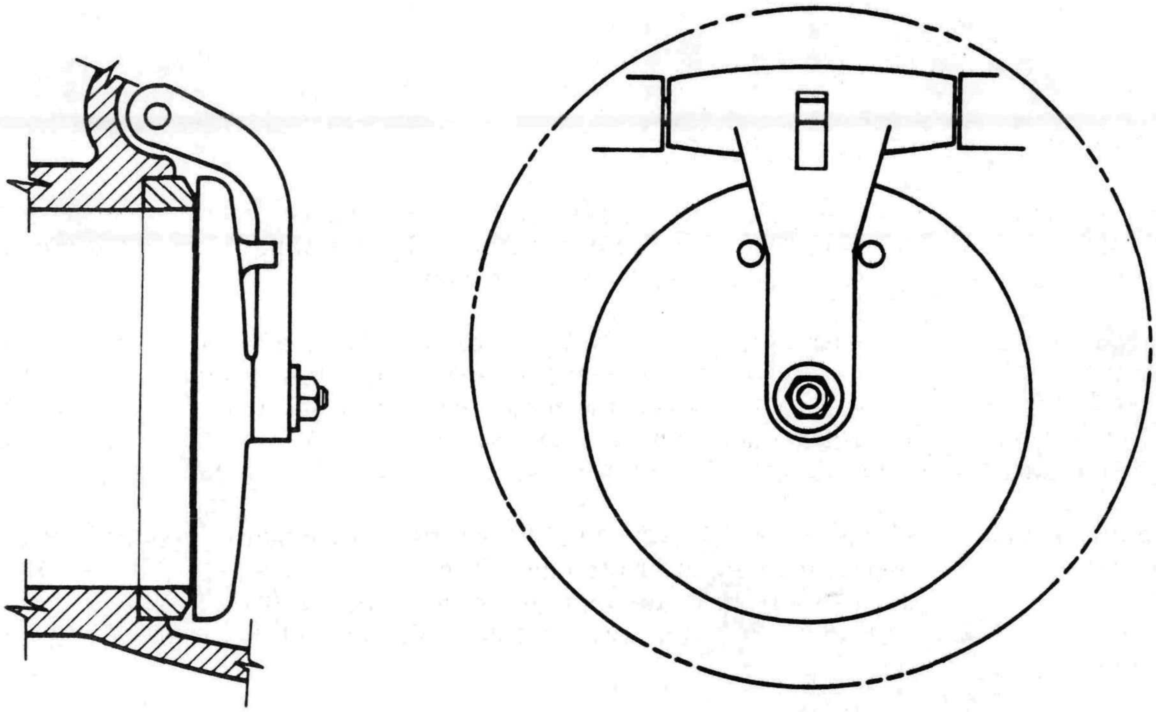
EVENT CENTER

Preliminary considerations regarding the event center are discussed referring again to Figure 2.1, which shows loop B inside containment and the locations of the most severe damage.

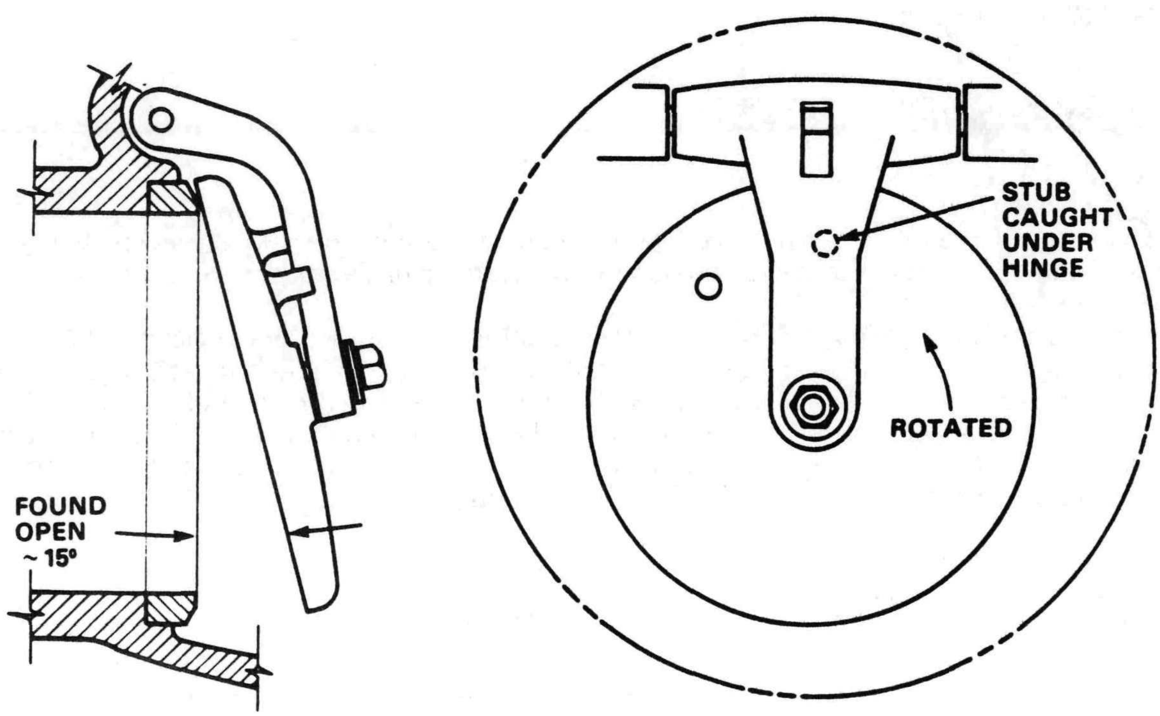
The severe nature of the damage from this event, combined with the long horizontal layout of the piping, suggests a subcooled water slug event scenario. In such an event all segments of pipe damaged directly by overpressure must be filled with water that leads up to a high pressure steam reservoir. The B steam generator is the only source of steam. Therefore, if the event involves a subcooled slug then the event center is either in the feedring or in the B feedline somewhere between support H00G and the steam generator.

FLUID STATE

For a subcooled water slug, there must be a source of high pressure steam and subcooled water flowing near the event center. The water level in steam generator B must have fallen beneath the feedring. Plant data are available to indicate the temperature and flow rate in feedwater loop B, as well as the steam generator level. Unfortunately, the strip chart recorders could not operate during the four minute loss of ac power, so data from the period immediately preceding the waterhammer is unavailable.



VALVE FWS-438 AS ASSEMBLED



VALVE FWS-438 AS FOUND

Figure 2.18 ROTATION OF THE CHECK VALVE DISK PREVENTED COMPLETE CLOSURE

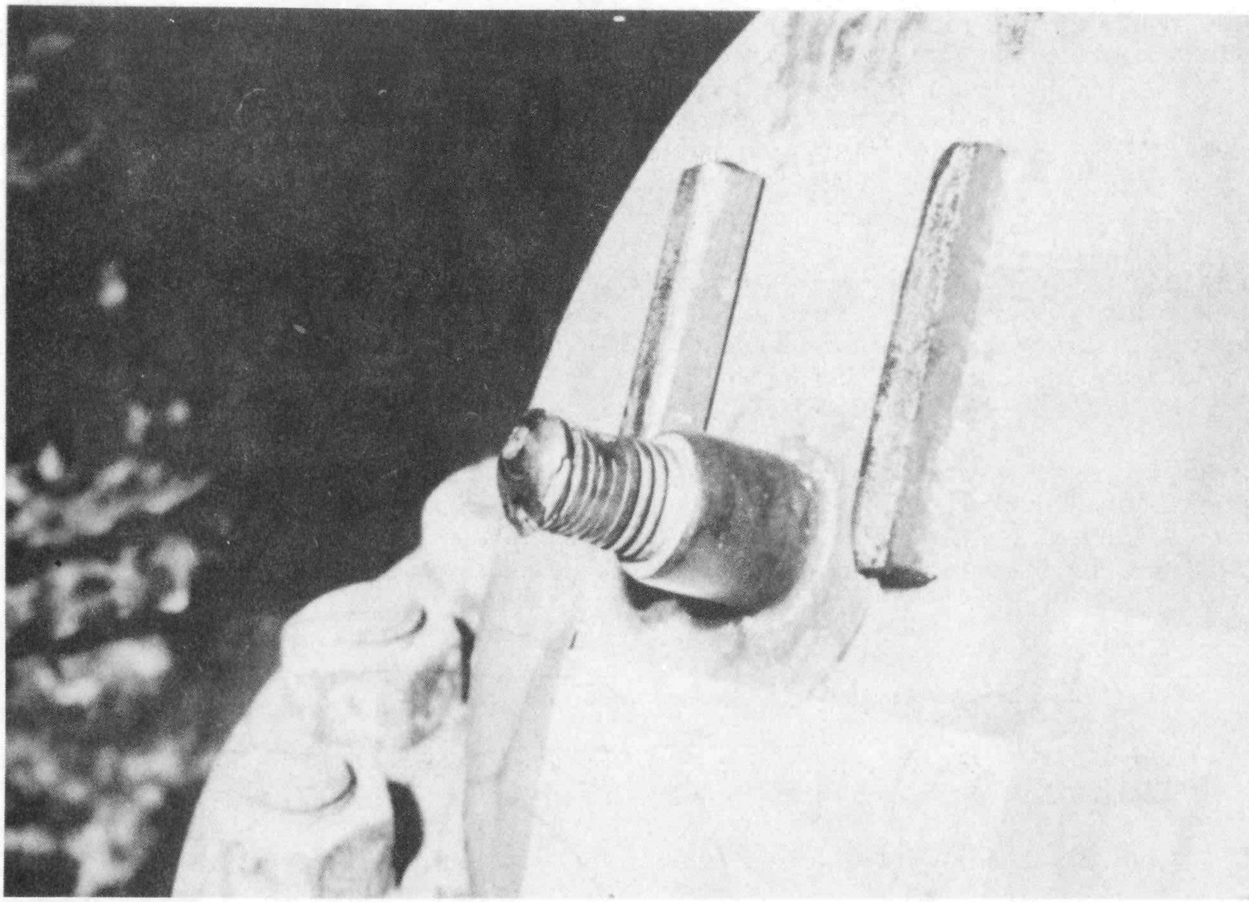


Figure 2.19 EVIDENCE OF WEAR IN CHECK VALVE FWS-346

The recorded water levels in all three steam generators are shown in Figure 2.20. The record indicates a steady level up until the event. The recorder does not function during the loss of power at 4:51 (time zero in the Figure). After recovery of plant power, the recorder remained off–scale low, indicating significant loss of water from the steam generator (the feedring is at 26% of the level range).

The record of the temperature in feedwater loop B is presented in Figure 2.21. The temperature recorder (TR–456) is located upstream of the main feedwater header, as illustrated in Figure 1.1. Up until the event, the line was at a steady temperature of about 365°F. At 4:51 the loss of power occurred and the recorder failed. When the power is restored the chart shows a large increase in temperature, indicating steam was present in the line. A subsequent rapid temperature drop indicates the injection of cool auxiliary feedwater. The rate of temperature decrease slows after loop B is isolated at 4:55.

The record of the flow rate in feedwater loop B is presented in Figure 2.22. Flow is measured just upstream of the loop B flow control station. Prior to the event, the strip chart shows increasing flow from 4:00 up to the event in response to a planned rise in reactor power. The record drops to zero during the loss of power, but remains low and offscale even after ac power is restored. This is as expected, since at this point the feedline was isolated.

Feedwater and steam pressure records from the event are shown in Figure 2.23. The feedwater pressure (measured at the feedwater header) is lost after the loss of power. The steam pressure record indicates high steam pressures (725 psig) throughout the waterhammer period. Steam pressure decreases after the event as operators cooled the plant.

In summary:

1. The feedring in steam generator B was uncovered, allowing steam into feedwater loop B,

2. The temperatures in loop B indicate the presence of high pressure steam, followed by subcooled auxiliary feedwater.

EVENT SCENARIO

A subcooled water slug event has already been postulated. The discovery of the failed check valves suggests a mechanism of void formation.

1. Void Formation

A large steam void formed in feedwater loop B due to blowdown of the steam generators backwards through the feedlines and out the ruptured flash evaporator. This blowdown was possible for two reasons: 1) five check valves failed leading from the steam generators to the ruptured evaporator (FWS–345, –346, –398, –438 and –439, Fig. 6.1.1), and 2) no makeup water could be pumped to the steam generators due to the four minute loss of ac power. A large fraction of the steam generator inventory was lost during this period. The blowdown continued until operators closed the feedwater isolation valves. Plant temperature records indicate the presence of steam upstream from the flow control stations.

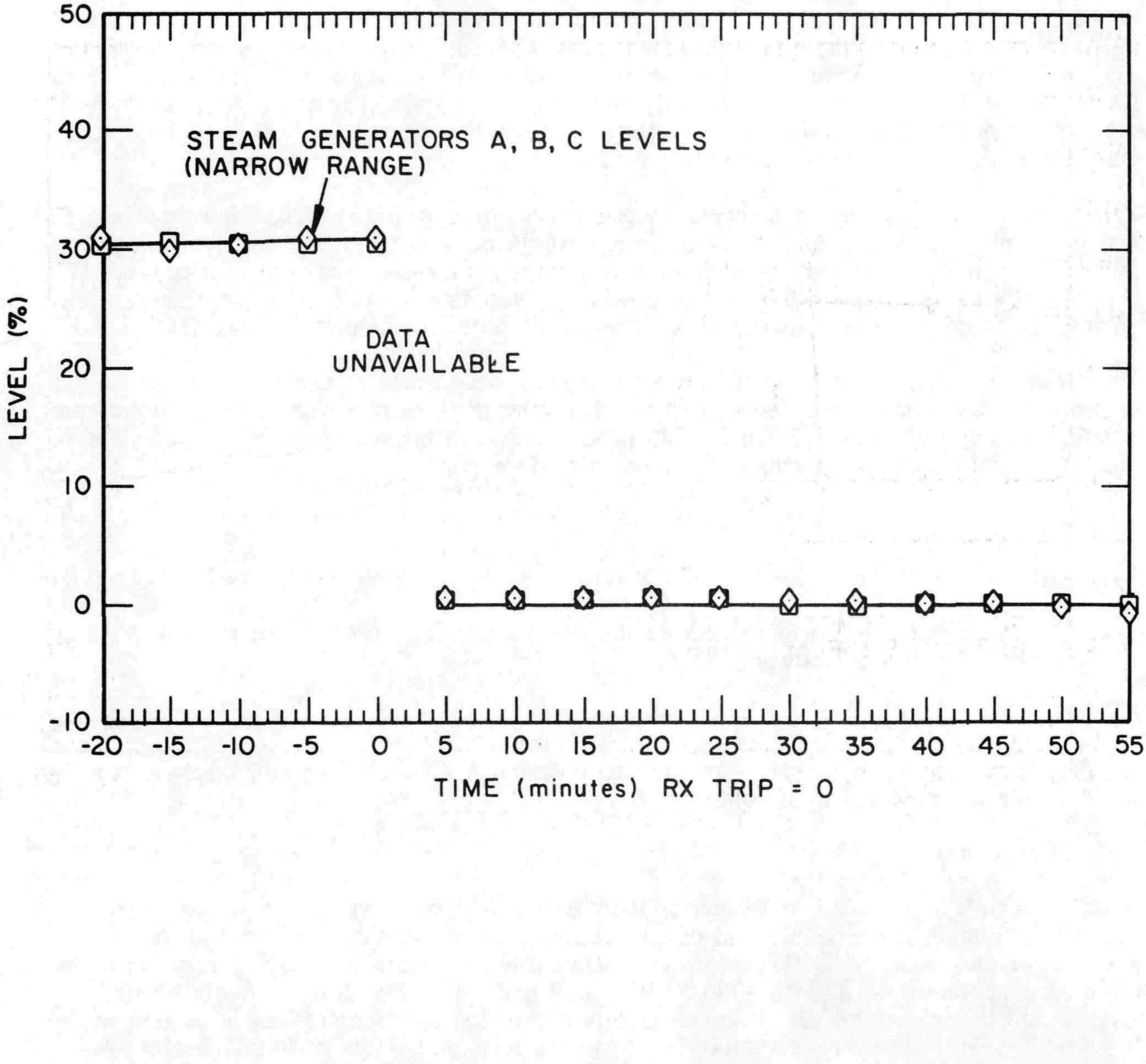


Figure 2.20 RECORDS OF WATER LEVEL IN THE STEAM GENERATORS

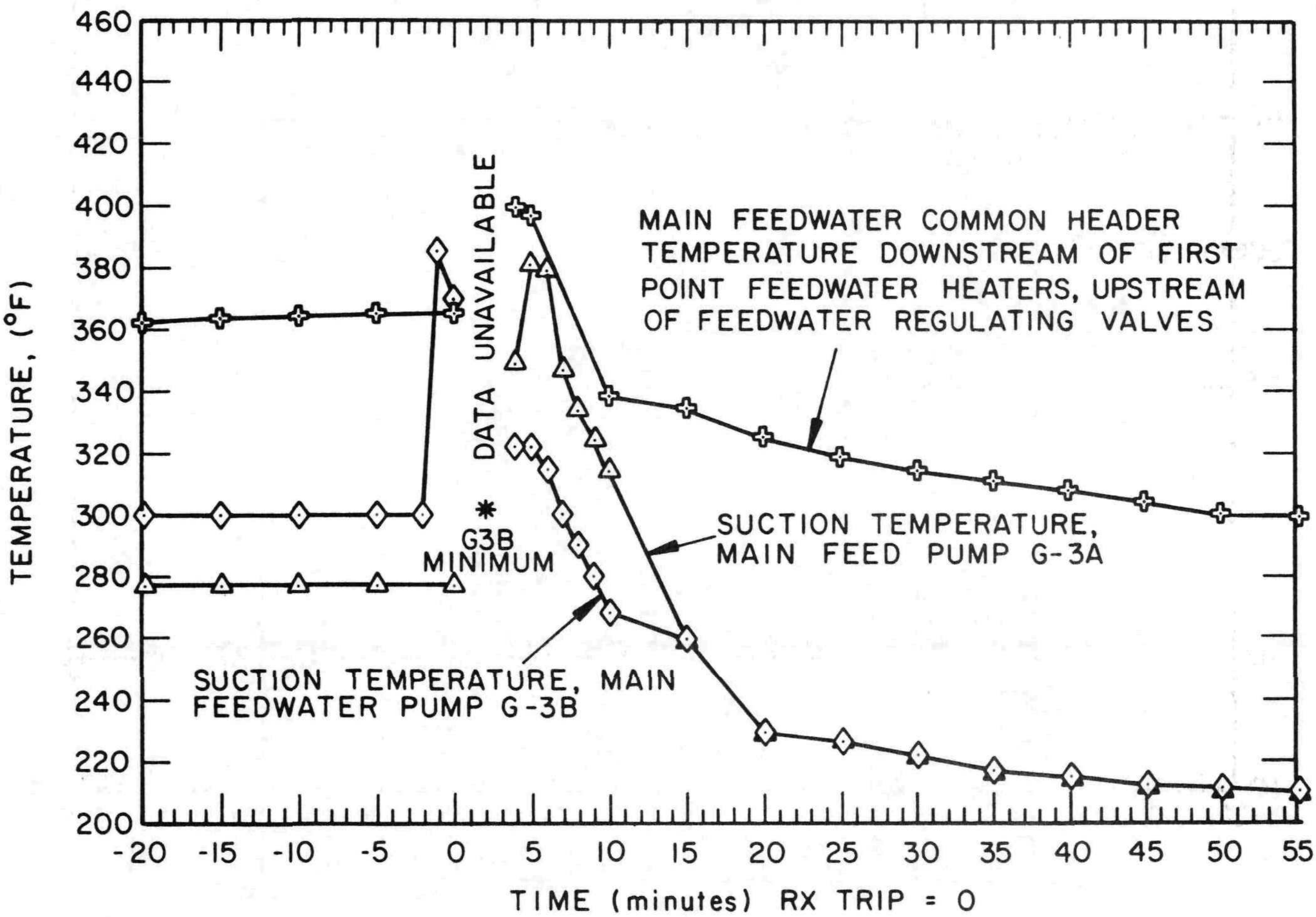


Figure 2.21 RECORDS OF FEEDWATER TEMPERATURE

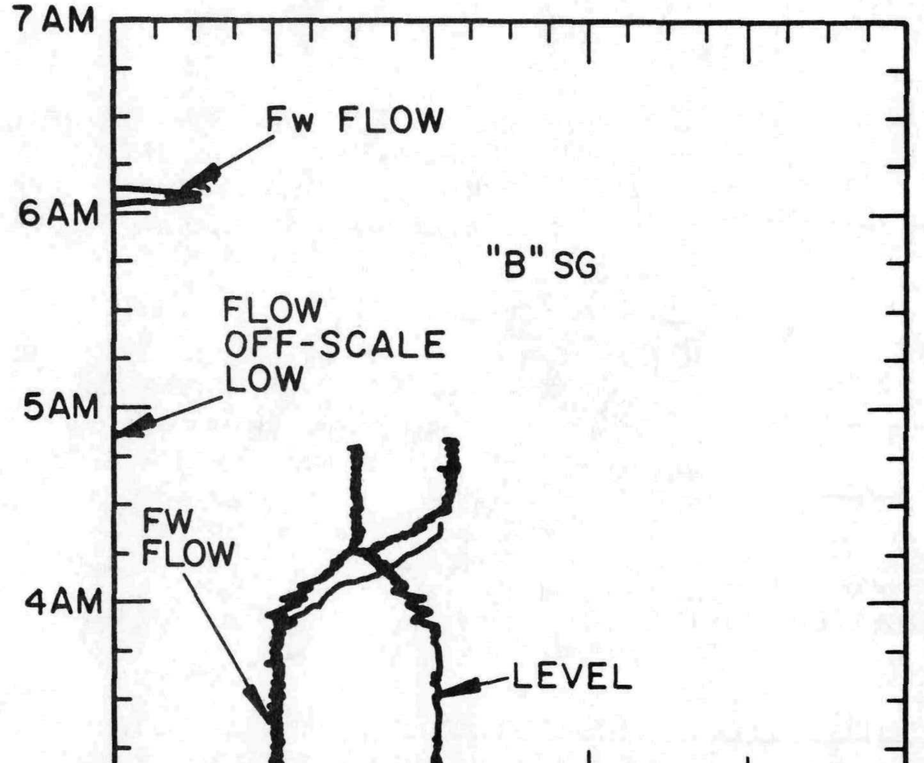


Figure 2.22 RECORDS OF FEEDWATER FLOW IN LOOP B

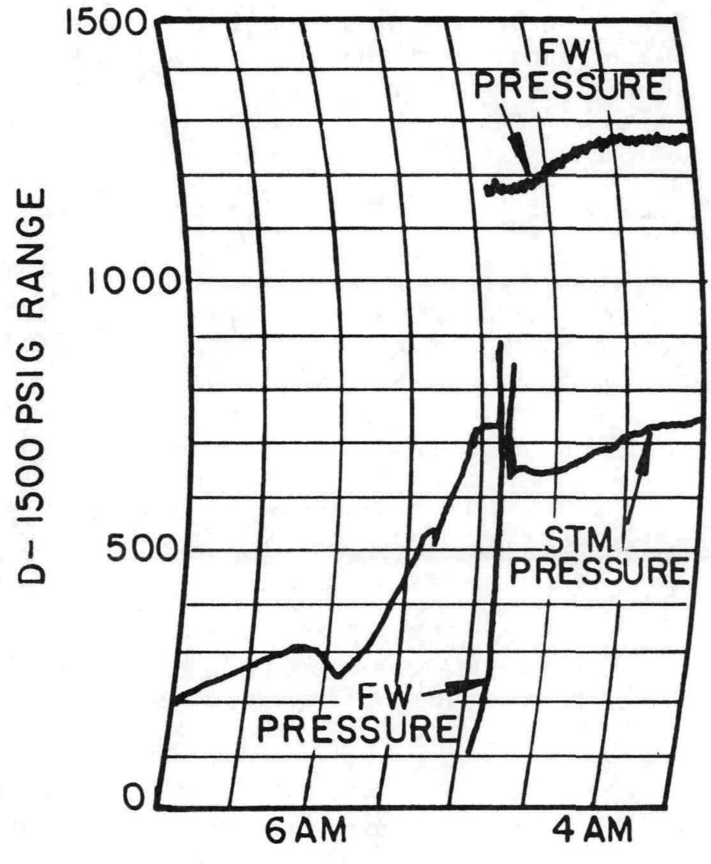


Figure 2.23 RECORDS OF STEAM AND FEEDWATER PRESSURE

2. Slug Formation

Slug formation occurred following the initiation of auxiliary feedwater (due to low water level in the steam generator). Assume for now that the low rate of AFW injection would not fill the loop B feedwater pipe in a plug fashion (this will be shown later by first order calculations). The feedline filled like a "pool," the water level rising gradually and presenting a large surface of subcooled water. The cool water surface was in contact with steam already present in the feedline.

This situation is illustrated schematically in Figure 2.24. Segment A shows a portion of the feedline isolated on the right and with a source of high pressure steam on the left. Cold AFW is injected at a low rate into the line near the isolated end, condensing steam and causing more steam to flow into the line. As more cool water enters the feedline, the rate of steam condensation increases because the surface area of cold water has increased. When the pipe is nearly full of water (segment B), rapidly condensing steam flows at a high rate over the free surface. Waves are generated which contact the upper surface of the pipe, isolate a pocket of steam, and are the nucleus of a liquid slug.

3. Slug Acceleration

The event scenario now proceeds just as in the previous case study. A liquid slug has trapped a pocket of hot steam which rapidly condenses and reduces the pressure in the pocket. The slug is accelerated into the low pressure void by the 725 psig steam acting on its other face. This is illustrated in segment C of Figure 2.24.

4. Void Collapse

Rapid condensation of steam in the void is enhanced by turbulent mixing as the slug accelerates. There is little cushioning effect from compressing the steam.

5. Impact

The high velocity slug of liquid impacts the water column filling the rest of the feedline. High pressure waves are generated which propagate down the feedline and cause severe damage.

Uncertainties in the Event Scenario

There are some uncertainties which must be resolved to support the above diagnosis. It must be shown that conditions in the loop B feedline were conducive to waterhammer. In particular, the flow regime should be examined to verify that slugs could have developed. Furthermore, it is puzzling that a waterhammer occurred in loop B but not in loops A or C. All three loops blew down due to failed check valves and were refilled slowly with auxiliary feedwater. The diagnosis should be able to explain this discrepancy.

SCOPING CALCULATIONS

Filling Loop B with Auxiliary Feedwater

The Froude number in the loop B feedline indicates the flow regime during the refill period. During this period the AFW pumps provided a total of 135 gpm per steam generator (see Table 2.1). The Froude number during refill will be evaluated using the combined AFW flow, because there was only a short period during which a single pump was operating.

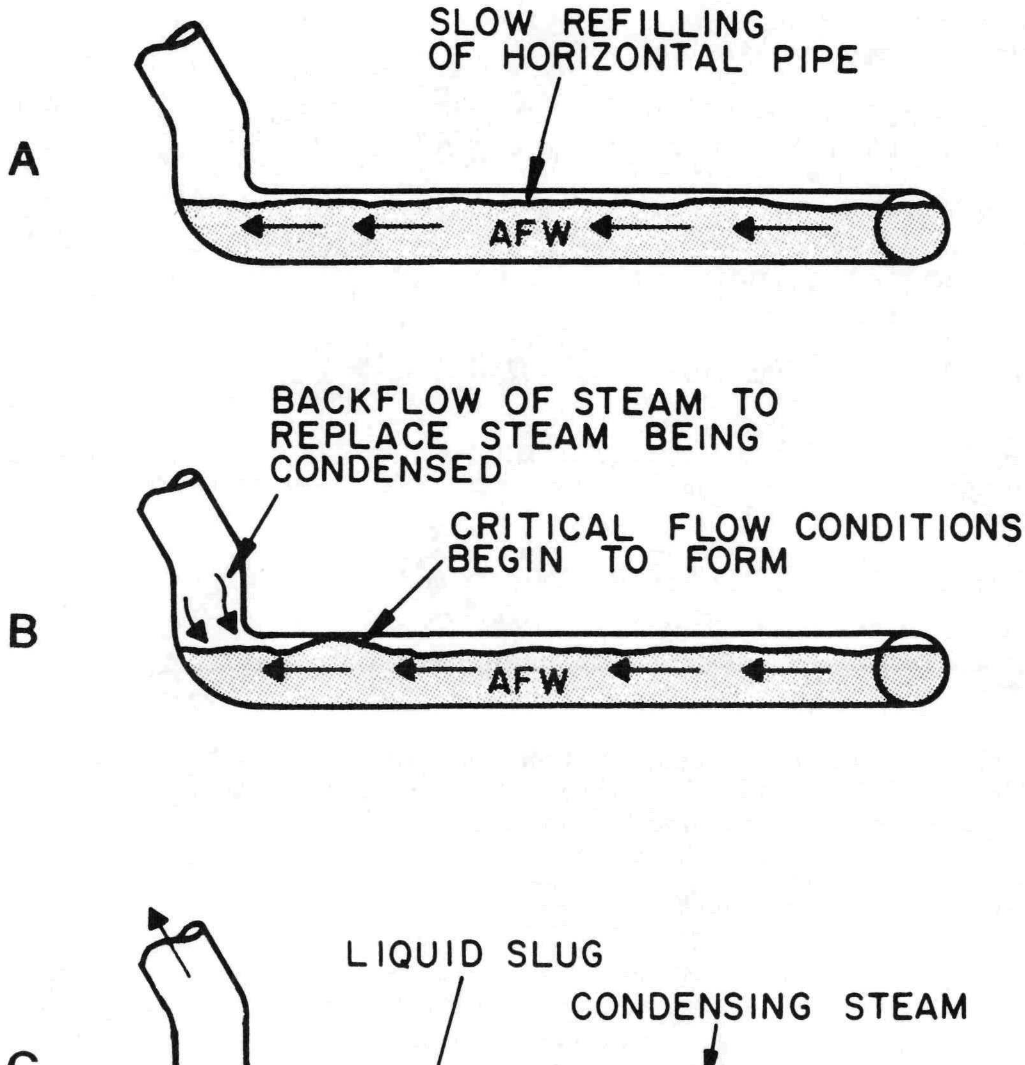


Figure 2.24 REFILLING OF LOOP B LEADING TO WATERHAMMER

Refer to Figure C.2 in Volume 1 for 135 gpm flowing in a 10 inch pipe. The Froude number is clearly less than 0.2, and in fact is equal to:

$$F = (0.25)(135 \text{ gpm})(10 \text{ in})^{-2.5} = 0.11$$

With both AFW pumps running, the B feedline would not run full.

The time for both feedpumps to fill the loop B feedline may be estimated. The problem is complicated because the rate of AFW flow was altered during the event. Referring to the timetable (Table 2.1), there are two refilling periods:

1. from 4:55 to 5:02 (7 minutes) flow was 135 gpm/SG, and
2. from 5:02 until 5:07 (5 minutes) flow was 25 gpm/SG

The length of the horizontal feedline from the closed isolation valve (MOV–20) to the riser near steam generator B is roughly 200 feet (see Figures 2.1 and 2.2). Refer to Figure C.1 in Volume 1 for the first refilling period. Using the formula,

$$\Delta t_B(135 \text{ gpm}) = (200/100) \times \Delta t_{100} = (2)(4.07)\frac{(10 \text{ in})^2}{(135 \text{ gpm})} = 6.0 \text{ min}$$

In five minutes, 5/6 of line B would be filled, leaving 33 "feet" of pipe empty (Actually the line did not fill up linearly in this manner. However the volume calculation does not depend on the actual shape of the empty pipe section).

The time to fill the remaining 33 "feet" of the B feedline at 25 gpm is:

$$\Delta t_B(25 \text{ gpm}) = (33/100) \times \Delta t_{100} = (0.33)(4.07)\frac{(10 \text{ in})^2}{(25 \text{ gpm})} = 5.4 \text{ min.}$$

The period of 25 gpm to the steam generators lasted only five minutes, thus it appears that a small void still existed in the feedline at the time of the waterhammer. A crude estimate of the void fraction in the B feedline based on these calculations is about 1%:

$$\text{feet of empty pipe, time of waterhammer} = \frac{0.4 \text{ min.}}{5.4 \text{ min.}} \times 33 \text{ ft} = 2.4 \text{ ft}$$

$$\frac{2.4 \text{ feet}}{200 \text{ feet}} \approx 1.0\%$$

The B feedline was very nearly full at the time of the waterhammer, and the uncertainty in these calculations probably exceeds the above estimate of void fraction. The initial conditions in the loop B feedline will require further investigation during the confirmation stage.

A and C feedwater lines

A rough isometric showing all three feedwater lines is presented in Figure 2.25. Loops A and C are each about 125 feet long, which is significantly shorter than loop B. At the time of the waterhammer, they would already have been filled up to their respective steam generators.

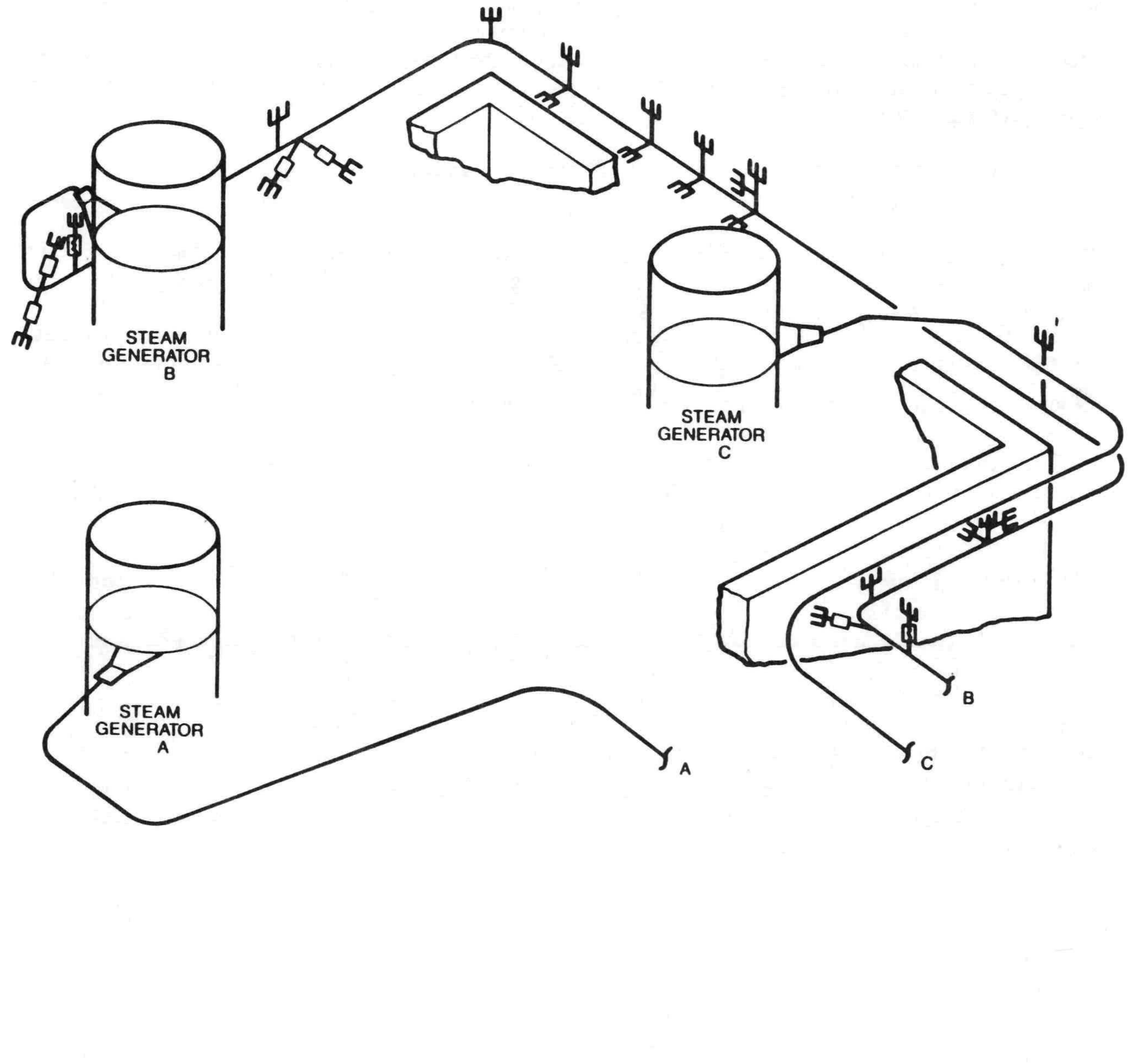


Figure 2.25 FEEDWATER LOOPS A, B AND C

This is a partial explanation why no waterhammer occurred in these two loops; it is still not clear why a waterhammer could not have occurred in these pipes before they were completely filled.

Magnitude of waterhammer loads

The overpressure due to impact of the subcooled water slug can be estimated based on the above calculations. The procedure is to calculate the characteristic overpressure, P_o (Figure C.7 in Volume 1), then use the modifying factors in Table C.2 (Volume 1) to correct for the specific geometry.

The pressure difference across the slug is 725 psi in this case. Referring to Figure C.7:

$$P_o \simeq 15{,}400 \text{ psi}$$

From Table C.2, this must be modified by the factor given by the bottom–most row, corresponding to initial slug length L_o and void fraction α. In this case $L_o = 0$ and the factor is simply $\sqrt{\alpha/(1-\alpha)} \approx 0.10$, so the modified overpressure is:

$$P_H \simeq 1{,}540 \text{ psi}$$

The corresponding segment force on the 10–inch feedline may be estimated using Figure C.11 in Volume 1:

$$F_H \approx 120{,}000 \text{ lb}_f$$

The pressure and load are relatively small. However, there are substantial uncertainties in these calculations, and the actual loads due to the subcooled water slug could have been much greater.

Pressure estimated from damage

The damage to the bonnet of check valve FWS–378 provides a simple way to estimate the pressure in the feedwater control station due to the waterhammer. The bonnet was held in place by 10 1–inch stainless steel bolts. The yield stress of these bolts is estimated at 70,000 psi. The bonnet cap is 10 inches in diameter. Therefore the minimum pressure on the cap necessary to stretch the bolts (see Section 4.3, Volume 1) is:

$$P = \frac{N\ \sigma_y\ d^2_{bolt}}{D^2_{bonnet}} = \frac{(10)(70{,}000 \text{ psi})(1 \text{ in})^2}{(10 \text{ in})^2} = 7{,}000 \text{ psi}$$

Since the pressure wave would have been reflected from this location, and the reflected wave magnitude is twice that of the incident wave, this implies an incident overpressure of 3,500 psi. This pressure is larger than our previous estimate of the waterhammer pressure, but within the range due to uncertainty in void fraction. For example, a void fraction of 10% would predict an overpressure of 4,620 psi.

Transmission past the pipe junctions

The 8–inch AFW line joins the loop B feedline just outside the containment penetration. This junction will attenuate the waterhammer pressure wave as is passes by towards the feedwater control station. The transmission coefficient may be estimated using the equations presented in Section 5.8 (Volume 1):

$$s = \frac{2 \times (10)^2}{(10)^2 + (10)^2 + (8)^2} = 0.76$$

So the pressure wave in the feedline is attenuated to 76% strength as it crosses the junction with the AFW line. A similar reduction would occur as the wave travels through the junction with the low flow bypass line, resulting in a total attenuation to about 65% original strength, or 3,300 psi. This is close to the pressure that was estimated to elongate the bolts in the bonnet of check valve FWS–348. This simple analysis neglects pressure attenuation due to damage in the feedline, but serves to illustrate the plausibility of the proposed event scenario. More elaborate analysis is left for the confirmation stage.

CONCLUSION OF THE INITIAL DIAGNOSIS

The initial diagnosis has produced a plausible event scenario. Estimated pressures and forces on piping are large and, within the uncertainty of these calculations, appear capable of producing the observed damage. There are significant differences in the lengths of the feedwater lines which might account for the absence of waterhammer in the A and C loops, though the exact mechanism is still unclear. Finally, initial estimates of the void fraction in loop B at the time of the waterhammer show that it was very nearly full.

2.6 CONFIRMATION

Major confirmatory actions were initiated to resolve the remaining uncertainties in the event scenario. The three primary activities concerned:

1. the magnitude of the pressure wave and its propagation,
2. initial conditions in the feedline, and
3. initiating mechanism and comparative evaluation (why there was no waterhammer in the A and C feedwater loops)

These items are discussed in turn below.

MAGNITUDE OF THE PRESSURE WAVE

The forces on the piping were estimated to lie between 123,000 and 198,000 lb_f. These estimates are based on detailed structural analysis of pipe displacement and component damage, as well as "time history anlaysis." Analysis of damage yielded both a maximum and minimum estimate for the axial load on the long section of feedwater loop B inside the containment building. Maximum loads were estimated based on components which had *not* failed. The force could not have been greater than that which would have broken these components. The minimum load estimate is based on the minimum forces necessary to cause the observed damage.

Time history analysis provided a load estimate of 160,000 lb_f. Time history analysis is an interactive process. The investigator starts with an estimated forcing function and compares the calculated pipe displacement with the actual displacement. A new forcing function is estimated based on these results. The solution is the force at which the calculated displacement is close to the observed displacement.

More precise estimates of the pressure necessary to stretch the check valve bonnet valves by 1/2" yield overpressures of about 10,000 psi, or 5,000 psi before reflection.

INITIAL CONDITIONS

The initial scoping calculations indicate uncertainty in the void fraction at the time of the event. The calculated void fraction is so small (1%) that there may actually have been no steam in the line at all. Furthermore, the waterhamer pressure is sensitive to the void fraction. More detailed analysis of the conditions in the B feedline were undertaken to confirm that condensation induced waterhammer was indeed responsible for the event.

The void fraction in loop B was estimated using three approaches:

1. sequence of events,
2. hydrodynamic instability, and
3. back–calculating from damage.

If all three methods yield similar estimates of a finite void fraction, this is evidence that a condensation–induced waterhammer occurred in the B feedline. The results of these calculations are summarized in Table 2.3. The estimated void fractions are indeed similar, and they support the subcooled water slug event hypothesis.

Sequence of Events Calculation

The sequence of event calculations are more elaborate versions of the initial scoping calculations, modified to account for major uncertainties. These uncertainties are due to flow instrumentation and the timing of events. Calculations of the void fraction in the B feedline were performed using the following ranges of parameters:

auxiliary feedwater flow rate:	120 to 170 gpm
time of AFW flow reduction:	4:59:30 to 5:00:30
reduced AFW flow rate:	25 to 40 gpm

TABLE 2.3: ESTIMATED VOID FRACTION AT INSTANT OF WATERHAMMER		
METHOD OF ESTIMATION	LOWER BOUND VOID FRACTION	UPPER BOUND VOID FRACTION
SEQUENCE OF EVENTS	0	10.5%
HYDRODYNAMIC INSTABILITY	4%	15%
EVENT DAMAGE	0.1%	22%

As shown in Table 2.3, the lower bound for the estimated void fraction is 0 and the upper bound is 10.5% This upper bound void fraction corresponds to a waterhammmer overpressure of 5,300 psi.

Hydrodynamic Instability Calculations

At high counter–current steam flow rates, hydrodynamic instability results in transition from stratified to slug flow. There is a critical void fraction for this transition which should equal the void fraction in loop B at the time of the waterhammer. Estimates of the void fraction made on this basis (shown in Table 2.3) range from 4 to 15 percent. The overpressure at 15% void fraction would be about 6,500 psi.

Empirical correlations are available to predict the conditions under which the transition to slug flow occurs. It is necessary to know the steam flow rate in order to estimate the critical void fraction. To encompass uncertainties, high and low estimates of steam flow were made. The steam flow rate depends on the rate of condensation. Low estimates assume steam condensation only on quiescent liquid surface within the feedline, while the high flow estimate assumes condensation on pipe walls as well.

Back–Estimates Based on Damage

Upper– and lower–bound estimates of the void fraction can be made based on the observed damage from the event. The range of void fractions in this case is 0.2 to 22 percent, as shown in Table 2.3. These values are in reasonable agreement with the other calculated ranges. The upper estimate is based on the damage to the FWS–378 valve bonnet. The pressure wave magnitude at the feedwater flow control station was 5,000 psi. The void fraction in the pipe at the time of slug impact was deduced using the methods in Appendix C. The lower void fraction is based on damage to pipe support structures along the feedline in the containment building. The minimum force is estimated at 123,000 lb_f. The force can be converted into an impact pressure which yields the lower estimate of the void fraction.

Conclusions

The two phenomenological estimates indicate that the waterhammer occurred when loop B was almost full. Critical steam velocities are not achieved until the pipe is almost full, which constricts the area for steam flow. Severe event damage indicates large pressure waves, which also occur at low void fractions. Thus it is not surprising that the sequence–of–events estimates indicate void fractions which are close to zero. The waterhammer pressures predicted by the more precise analyses are in good agreement with the pressure necessary to damage the bonnet of check valve FWS–378.

INITIATING MECHANISM AND COMPARATIVE EVALUATION

During the transient the A and C feedwater loops were both filled with water after filling with steam. At some point, each loop would have had a void fraction equal to the critical void fraction for slug formation. Why then didn't these loops experience a waterhammer? The proposed event scenario must explain this difference.

A detailed analysis of the thermal hydraulic phenomena in the feedlines was performed. The three key parameters which influence the potential for waterhammer are the length of the feedwater pipe, the pressure, and the AFW flow rate. A map showing the main results of the analysis is presented in Figure 2.26. The map applies for a specific steam pressure (725 psig in this case) and shows a range of AFW flowrates as a function of feedline length. Waterhammer is possible only within the indicated region.

Longer feedlines are susceptible to waterhammer over wider ranges of AFW flow. Therefore the B feedline, which is significantly longer than both the A and C lines, has a greater potential for waterhammer. The A and C loops were completely filled at a high AFW flow rate (120 gpm) while the B loop was filling at a low AFW flow rate at the time of the waterhammer (25 gpm). These points are indicated in the Figure, showing that the A and C loops operated well outside the range of flows in which waterhammer may occur. The B loop, on the other hand, falls within that range. This analysis provides the key explanation for why waterhammer did not occur in the other two feedwater loops.

Waterhammer will not occur if the AFW flow rate exceeds a certain limit. This is why the A and C lines did not suffer from a waterhammer. The limit is determined by the condensation rate of steam. If the water flow rate exceeds the condensation rate, then no net steam will flow into the line and waterhammer will not occur. There is also a lower limit on AFW flow, below which waterhammer cannot occur. If the water flow rate is so low that the entire volume of liquid in the pipe is heated to near–saturated conditions, then a subcooled water slug event cannot occur. This lower limit is usually much less than 5 gpm.

A simple air/water experiment was performed to study the refilling process in a 6–1/4 inch pipe at two injection flow rates. Results of the experiment confirm that with a very high injection flow liquid slugs disappear shortly after their creation. This finding supports the theory that a water slug generated by the steam flowing back toward the steam generator will collapse due to lack of accelerating force. It also provides corroborating evidence that a waterhammer could not have occured in the A and C feedwater loops.

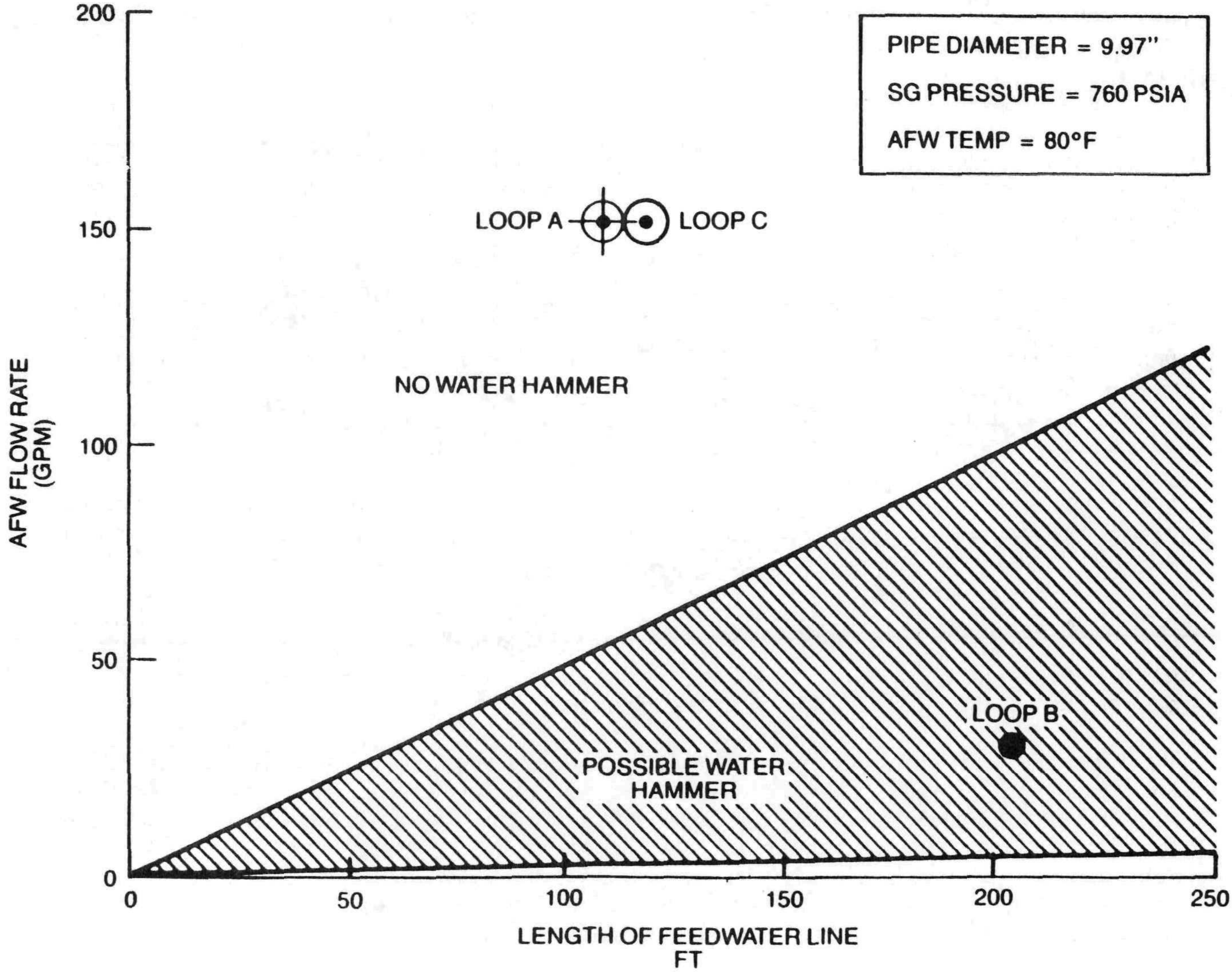


Figure 2.26 ACTUAL CONDITIONS NECESSARY TO INITIATE WATERHAMMER

CONCLUSION OF CONFIRMATION

These confirmation activities lend a high degree of confidence to the proposed event scenario. It has been shown that the loads estimated from plant damage are consistent with the forces which would be generated in a subcooled water event. The proposed scenario satisfies the boundary conditions from the timetable of events. Finally, the proposed mechanism explains the lack of waterhammer in the A and C feedwater loops.

2.7 DISCUSSION

Though this event was triggered by the failure of five check valves, there are some general lessons about waterhammer.

1. Collapse of very small steam voids can lead to large piping loads. It only requires a small liquid slug to fill a small void, and a small slug can quickly reach high velocities. Thus waterhammers caused by subcooled water slugs at low void fractions can be very damaging.

2. Waterhammer can be prevented by ensuring that the subcooled water flow rate is high enough. In the case of the A and C feedlines, flowrates down to 50 gpm would have been sufficient, and for the B feedline 80 gpm could have prevented the waterhammer.

3. Significant forces may be generated far from the event center. Check valve FWS–378 is located 200 feet from the point of slug impact.

3 A TRAPPED VOID COLLAPSE IN A PWR FEEDWATER SYSTEM

This case study concerns a waterhammer during an inadvertent steam generator blowdown.

3.1 Purpose of This Case

This case study:

1. illustrates an event scenario including dynamic column separation.
2. illustrates another mechanism of check valve failure with the potential to cause damaging waterhammer,
3. shows how operating procedures can provide diagnostic information,
4. illustrates the use of fluid transient analysis for confirmation.

3.2 System Description

This event involves the feedwater system and sections of the condensate system in a pressurized water reactor.

STEAM GENERATOR AND FEEDWATER SYSTEM

The steam generator and feedwater system in this case are similar to those described in the previous cases. A rough schematic showing the important components is presented in Figure 3.1. The relevant section of the feedwater system extends from the feedwater header to the #3 steam generator. From the header, feedwater flows through the 23BF19 valve through the 14" feedwater line at el. 121'. A low flow bypass valve is provided in parallel with the BF19 valve. In the turbine building yard the feedpipe is raised to el. 138', then drops to 98' in the penetration area. The feedwater then flows through the BF22 stop/check valve, enters containment, rises to el. 144' and joins with the steam generator feedring. The main feedwater pumps were bypassed and are not shown.

CONDENSATE SYSTEM

Portions of the condensate system are also illustrated in Figure 3.1. During the waterhammer, the condensate system was operating in condensate polishing mode. Condensate polishers are full flow, in–line demineralizers which are operated routinely to prevent debris from building up inside the steam generators. In condensate polishing mode, the condensate pump takes suction from the condenser and pumps 7,000 gpm of water through condensate polishers and the feedwater heaters to the feedwater system header. Water from the header passes through a strainer and flows through the condensate recirculation valve back to the condenser.

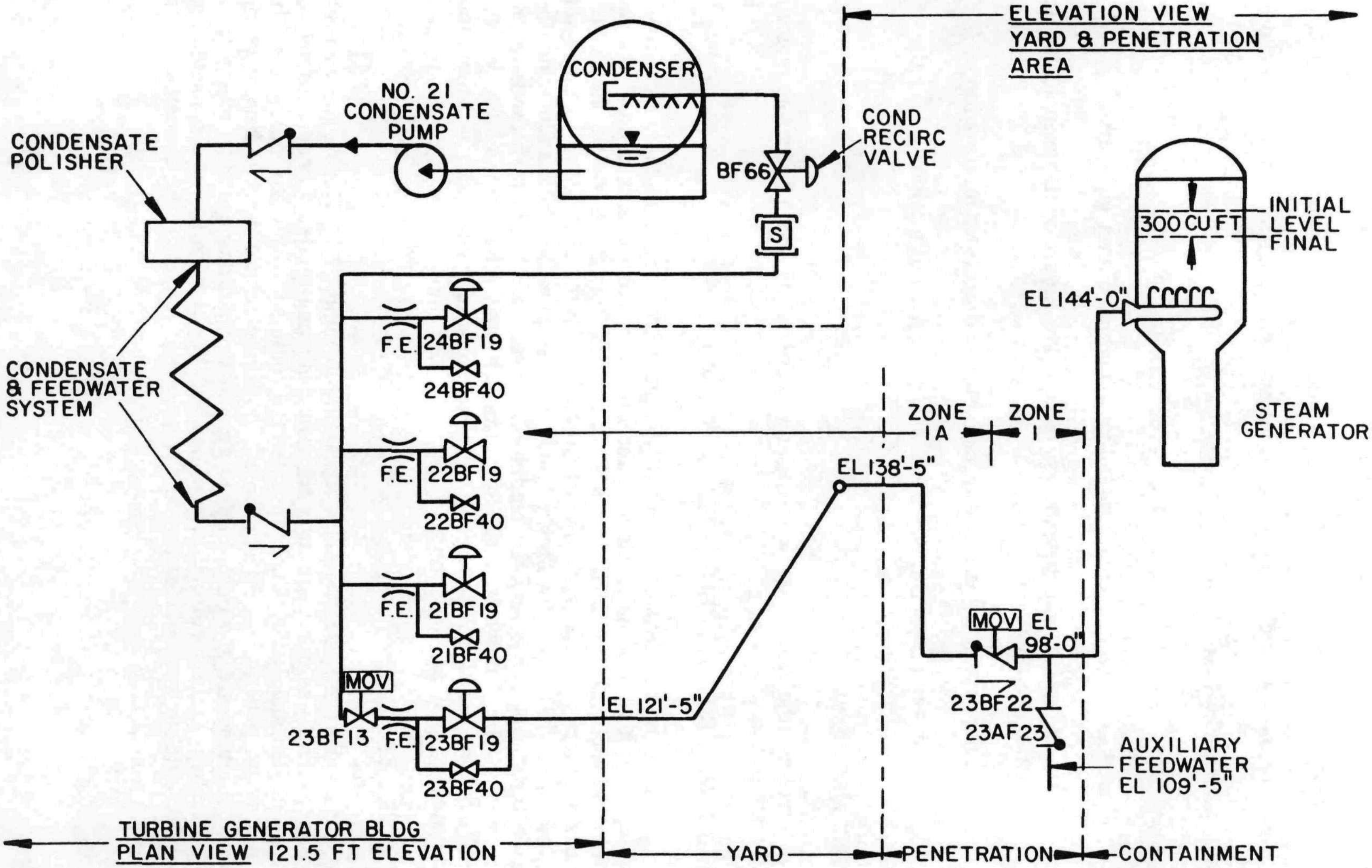


Figure 3.1 SKETCH OF CONDENSATE AND FEEDWATER SYSTEMS

3.3 Sequence of Events Leading to Waterhammer

Prior to the waterhammer, the reactor was in Mode 3 (hot standby) following a turbine and reactor trip. The reactor was at zero power and the reactor coolant system temperature and pressure were 547 F and 2,240 psig, respectively. Steam generator pressure was holding steady at 1,000 psig and the water level was steady at 41% of the wide range. Auxiliary feedwater was supplied to all steam generators to maintain the primary system temperature

The status of the condensate and feedwater systems is described referring to Figure 3.1. The #21 condensate pump was in service for secondary coolant cleanup through the condensate polisher. All feedwater heater strings were in service and the condensate recirculation valve (BF66) was open. All steam generator feedwater regulation valves (21–23 BF19) were closed, as were the bypass valves (21–23 BF40). The steam generator isolation valves (21–23 BF13) were all open, not having been shut following the turbine trip. Likewise, the motor operators of the feedwater stop/check valves (21–23 BF22) were still in the OPEN position. This does not imply that the valves were open, simply that they were not held shut. They should still have functioned as check valves to isolate the steam generators.

A summary timetable of significant events is presented in Table 3.1. In preparation for plant startup, surveillance procedures require that the feedwater regulation and bypass valves (BF19 and 40) be tested in each feedwater line. The test procedure requires that each valve be opened, and then timed closed. Testing had been satisfactorily completed on valves 21BF19, 21BF40, 22BF19 and 22BF40.

At 1633 hours, 23BF19 was opened. Immediately afterward a loud "rumbling" noise was heard in the control room and throughout the plant. All control console push–button backlights were varying in intensity, and all meter indications were fluctuating. Operators believed that a main steam line may have ruptured. The 23BF19 valve was closed, as well as the feedwater isolation valves (21–23 BF13). Primary plant parameters remained steady and stable throughout the event.

3.4 Description of Damage

The entire feedline, from the #3 steam generator through the recirculation line to the condenser, was visually inspected. The feedline inside containment showed no evidence of damage. Inside the turbine building and south penetration the feedline insulation was damaged or missing in some places. The feedline supports suffered the following damage: two hangers were broken, one hanger was bent, and one snubber was found locked up at the highest elevation of the piping run between the BF22 and BF19 valves. Trunnions supporting the riser to the #3 steam generator were also found damaged. Five other impaired snubbers were found, possibly damaged by the transient.

The steam generator stop/check valve (23BF22) was found to be leaking. The #23 feedwater regulation and bypass valves both suffered internal damage. The #23 flow metering nozzle was displaced towards the BF13 valve (see Fig. 3.2). Several pressure gauges along the feedline (rated from 600 to 2,000 psi) were found overranged.

The #21 and #22 feedlines were walked down as well, but no damage was found.

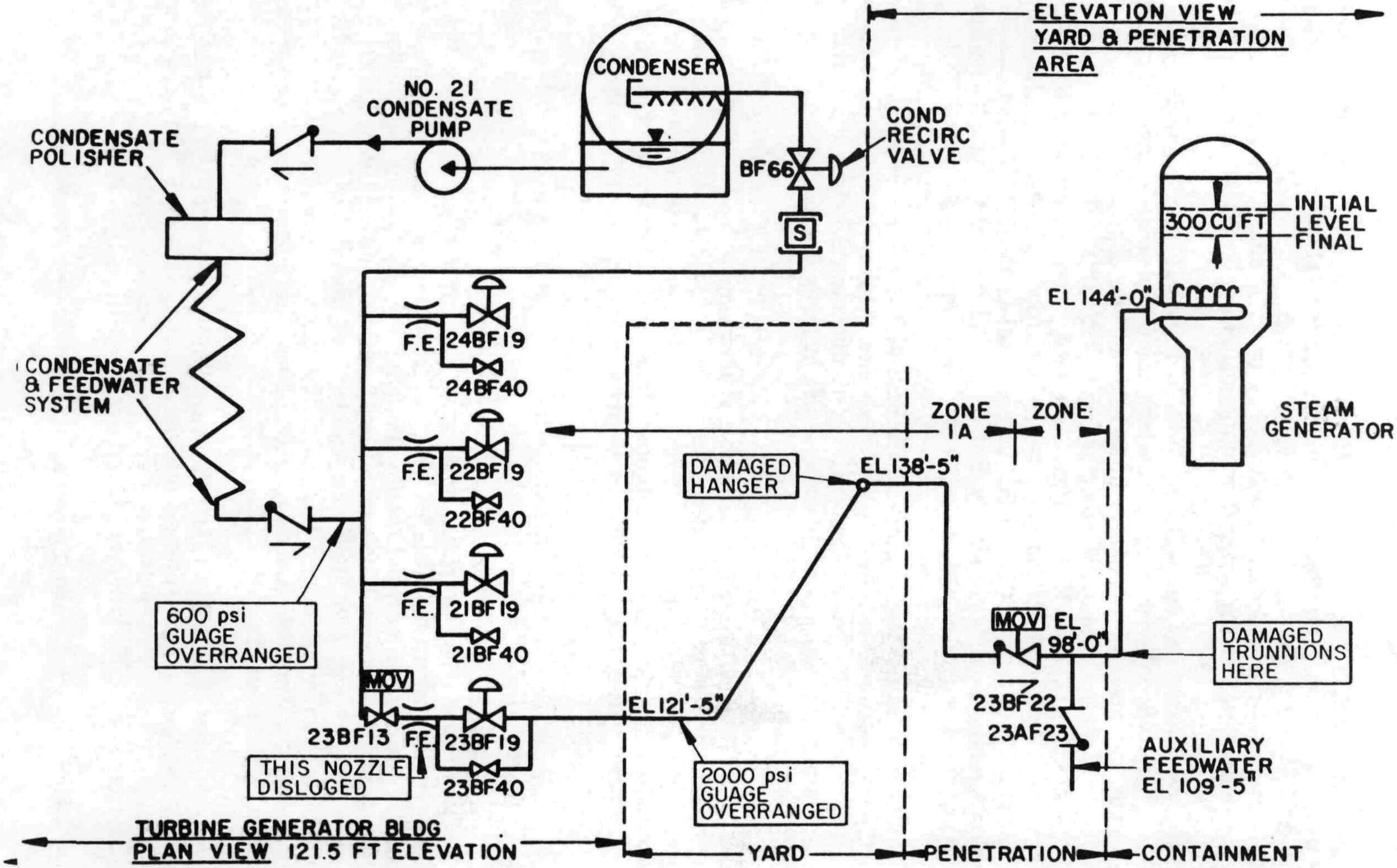


Figure 3.2 DAMAGED PRESSURE GAUGES IN THE CONDENSATE AND FEEDWATER SYSTEMS

Table 3.1. TIMETABLE OF EVENTS LEADING UP TO THE WATERHAMMER	
Prior to event	Reactor in mode 3 (hot standby) following a turbine trip. RCS temperature = 547°F, SG pressure = 1,000 psig. Steam generators supplied with AFW. #21 condensate pump in–service for secondary cleanup through the condensate polisher.
16:05	Prior to restart, in–service testing of Feedwater Regulating Valves (21–23 BF19) and Feedwater Regulating Bypass Valves (21–23 BF40) is begun.
16:30	Testing complete on 21 BF19, 21 BF40, 22 BF19 and 22 BF40.
16:33:05	23 BF19 is opened; operators hear a loud rumbling noise.
16:33:20	Operators activate closures of 23 BF19
16:33:25–35	Rumbling noise stops
16:33:45	23 BF19 completes closure

3.5 Waterhammer Diagnosis

EVENT CENTER

An event center is not obvious from inspecting the system diagram. There are long lengths of horizontal pipe, but a subcooled water slug event could not have occured because the water level in the steam generator remained above the feedring at all times. Likewise, voids could not have formed by draining down from high points because the system was at high pressure throughout the event (at least 450 psig set by the condensate pump).

Instrument damage provides an important clue in this case, suggesting that the event center lies in the #3 feedline between the BF19 valve and the steam generator. The locations of damaged pressure gauges are shown in Figure 3.2. A 2,000 psi pressure gauge was found overranged between the BF19 and BF22 valves, indicating that overpressures exceeded 2,000 psi in the #3 feedline. On the feedwater header, a 600 psi pressure gauge was found overranged but a nearby 1,500 psi gauge was undamaged. Overpressures in the header were therefore less than 1,500 psi, perhaps indicating that the waterhammer wave was attenuated as it propagated from the event center in the feedline.

FLUID STATE

The #3 feedline and feedwater header were initially full of condensate at 70 F. The initial pressure in the feedwater header was 450 psig. The #3 steam generator was initially at 1,000 psig and 547 F.

The valve lineup during the event suggests that there was no net flow through the feedline. However, records of the steam generator water level indicate that this could not have been the case. A strip chart showing the steam generator water level from around the time of the event is shown in Figure 3.3. There are two notable features of the water level record. First, the level shows a very sharp spike immediately following the opening the of BF19 valve. Following the spike there is a more gradual (about 20 seconds long) decrease in water level.

The sharp rise in steam generator water level is due to level swell which occurs upon depressurization. The steam generator depressurized when the BF19 valve was opened, so there must have been a direct fluid path from BF19 to SG#3. This could only happen if the BF22 check valve failed (recall that the motor–operator was not used to actively shut the valve).

The gradual decrease in water level following the level swell indicates a flow of liquid from the steam generator into the feedpipe. This decrease in inventory is further evidence for check valve failure.

After the event, the BF22 stop/check valve was inspected and no unusual conditions were found which might have prevented its closure.

EVENT SCENARIO

Based on the above considerations, the following event scenario is postulated. The scenario is illustrated schematically in Figure 3.4.

1. Void formation

The BF22 stop/check valve was stuck open due to loose debris in the valve seat, as illustrated in section 1 of Figure 3.4. As a result, the initial pressure in the #3 feedline from the BF19 feedwater control valve to the steam generator was roughly 1,000 psi. The BF19 valve was opened for testing under these unusual circumstances. Normally the pressure difference across the valve is small and acts in the direction of normal feedwater flow. In this case, however, a large differential pressure (probably over 500 psi) acted on the valve opposite to the normal flow direction. As a result, the valve actuator controls acted to very suddenly open the valve completely.

In response to the sudden valve opening, a depressurization wave was initiated in the feedline which travelled upstream to SG#3 (section 2, Figure 3.4). The depressurization wave eventually reached the steam generator and caused the level swell indicated in the strip chart. At this point water began to flow from the steam generator through the #3 feedline back to the condenser, illustrated in section 3 of Figure 3.4.

When the hot steam generator water flowing through the feedline was reduced to 450 psi, it flashed to steam. Voids formed in the feedline at the interface between the initially cool water and the relatively hot steam generator water. Probably recondensation and flashing occurred continuously at the hot/cold interface, causing the "rumbling" noises heard by plant personnel.

Flow from the steam generator stopped when the BF22 stop/check valve closed. It is speculated that a high flow rate of water back through the stuck valve eventually dislodged the debris which prevented it from closing (section 4, Figure 3.4). The check valve slammed shut and prevented further flow in the feedline.

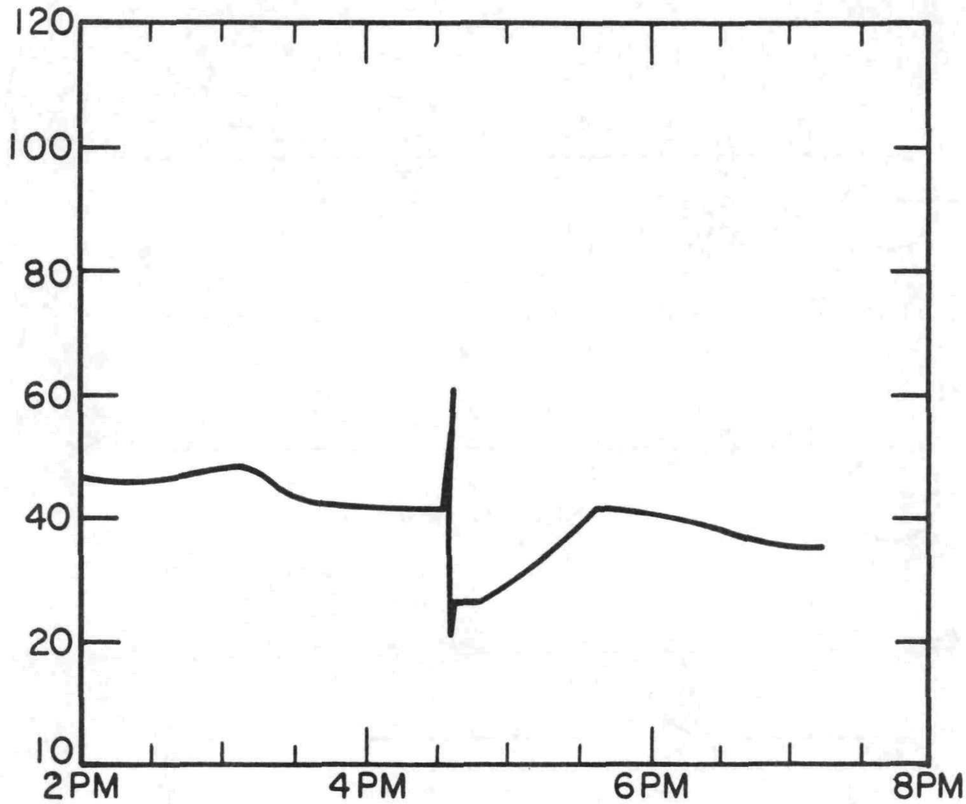


Figure 3.3 RECORD OF STEAM GENERATOR WATER LEVEL

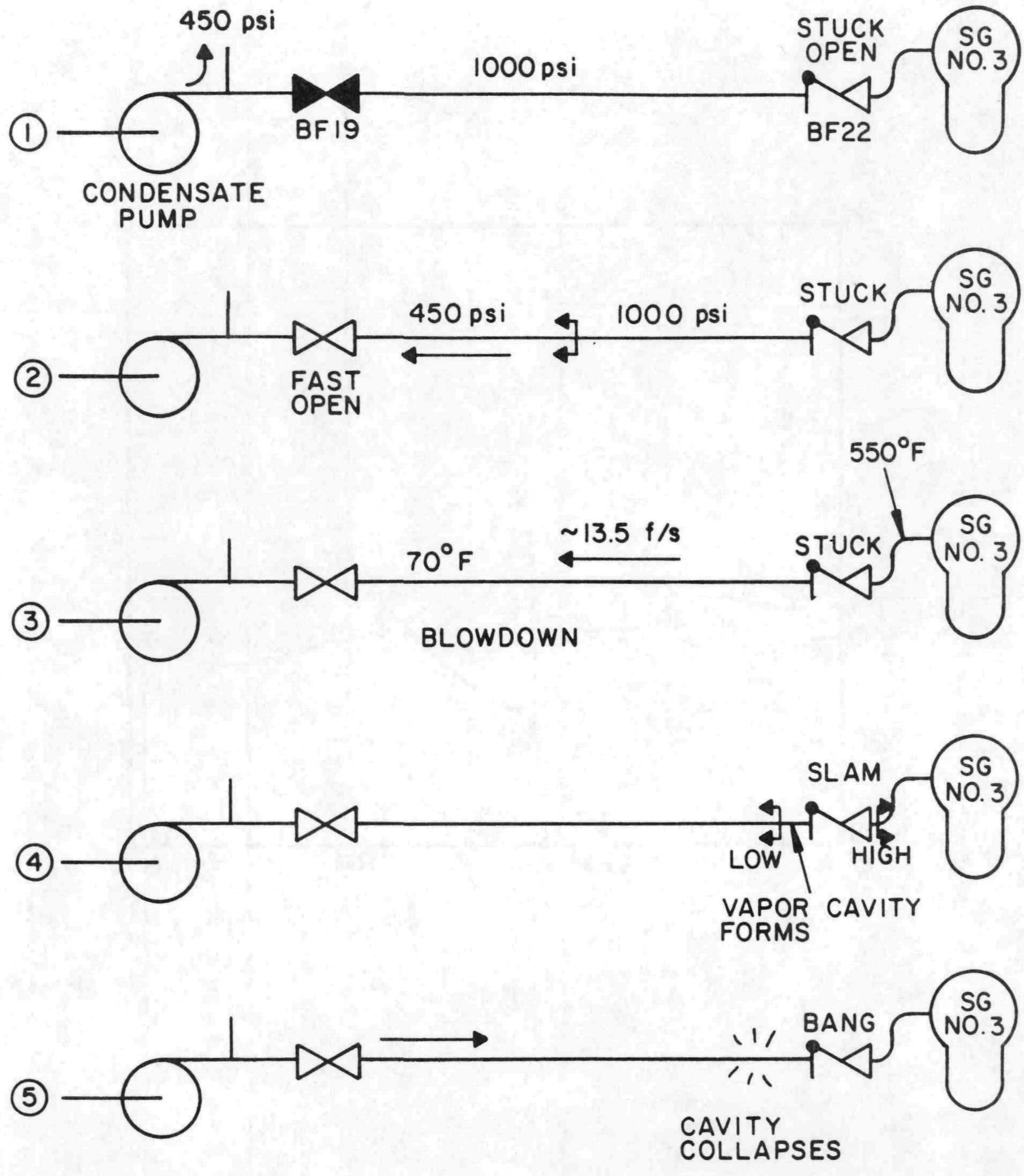


Figure 3.4 EVENT SCENARIO FOR VOID COLLAPSE IN THE FEEDWATER SYSTEM

Two pressure waves were generated when BF22 slammed shut. A low pressure wave travelled downstream from BF22 towards the BF19 feedwater regulating valve. The pressure behind this wave was less than the liquid vapor pressure, so vapor cavity formed on the condenser side of the BF22 stop/check valve. This vapor cavity is the void for the condensation–induced waterhammer. A second, high pressure wave travelled upstream through the feedline from BF22 to the steam generator.

2. Slug formation

The slug to be accelerated is the water column flowing through the feedline extending from the vapor cavity to the #1 condensate pump. It is formed after the low–pressure wave from the check valve has dissipated in the condensate system, leaving behind a stagnant water column.

3. Slug acceleration

The #1 condensate pump operates continuously throughout this transient. After the low pressure wave is gone, it acts to accelerate the water slug through the feedpipe to collapse the vapor cavity.

4. Void Collapse

The pumped water column raises the cavity pressure above the saturation level, causing the steam to condense. The void collapses in front of the advancing water column.

5. Impact

The pumped water column eventually condenses the entire vapor cavity and strikes the condenser–side of the BF22 stop/check valve, as shown in Section 5 of Figure 3.4.

This event scenario is consistent with records of previous plant operation. Previous startups from hot standby did not involve recovering from a turbine trip, as this case did. During normal startup the BF13 isolation valves would still have been closed during the tests of the BF19 regulating valves. Thus, even if the stop/check valve had been stuck open previously, flow through the feedline would have been impossible during the BF19 stroke test. Following the turbine trip, however, auxiliary operating procedures (AOPs) were used. These procedures did not call for the BF13 valves to be closed before testing the BF19 valves. In this case a faulty stop/check valve could and probably did result in backflow down the feedline.

The proposed event scenario is consistent with available plant evidence, such as the reconstructed timetable of events and the steam generator water level record. There are several uncertainties which remain, especially whether a vapor cavity could have formed after the check valve slam and whether the loads generated by the cavity collapse would be sufficient to cause the observed plant damage. These questions can be partially addressed by the following scoping calculations.

SCOPING CALCULATIONS

1. Flowrate and amount of hot water in the feedline (prior to the check valve slam)

The flowrate in the feedline during the steam generator blowdown can be estimated from the decrease in steam generator water level. Discounting the initial level swell, the steam generator level indicated in Figure 3.3 dropped from 41% to 26% of the narrow (12 foot) level range during the event. This represents about 210 ft^3 of water drained from the steam generator (this number is determined from a vendor–supplied curve showing steam generator volume vs. level). The flow period lasted from 20 to 30 seconds, implying a flowrate between 7 and 10.5 ft^3/s (3,100 to 4,700 gpm).

It is important to estimate how far the hot (547 F) steam generator water was able to travel down the feedline before the check valve slam. If the hot water extended beyond the BF22 stop/check valve, then vapor cavity formation after the slam is much more likely. Feedline #3 is a 14" i.d. pipe. The time to fill 100 feet of the feedline is given by Figure C.1 in Volume 1:

$$\Delta t_{100} = \frac{(4.07)(14\,in)^2}{(3{,}100\ gpm)} = 0.26 \text{ minutes (or 15 seconds)}$$

This calculation uses the lowest estimated flowrate to give a conservative estimate of the hot water penetration. In 20 to 30 seconds, the hot water could have travelled 130 to 200 feet down the #3 feedline. The distance from the steam generator to the BF22 stop/check valve is roughly 100 feet. Therefore, very hot water was probably in the section of pipe between the BF22 and BF19 valves when the check valve slam occurred.

2. Waterhammer pressure and void formation (due to check valve slam)

The waterhammer overpressure due to sudden deceleration is estimated using Figure C.8 (Volume 1), for a 14" pipe and 3,100 gpm of flow. The pressure difference across the low–pressure wave is approximately 600 psia. The saturation pressure of the hot steam generator water can be read from Figure D.1 (Volume 1), and is found to be over 1,000 psia. Therefore, the low pressure wave generated by the check valve slam reduces the pressure of this water below its vapor pressure. A vapor cavity could have been created due to the sudden check valve closure.

3. Waterhammer pressure due to void collapse

The slug acceleration is driven primarily by the #1 condensate pump, which was operating at 7,300 gpm (in cleanup mode) throughout the transient. An estimate of the waterhammer pressure is obtained by assuming that the slug in the feedline has reached this flowrate prior to impact. Refer again to Figure C.8 (Volume 1) for a 14" pipe and a flowrate of 7,300 gpm. The indicated pressure pulse is roughly 800 psia.

4. Piping loads

The axial force due to the vapor cavity collapse may be estimated using Figure C.11 in Volume 1. An overpressure of 800 psia in a 14" pipe implies a segment force of roughly 120,000 lb_f. Qualitatively, this is a large force and appears sufficient to have caused the observed piping damage.

CONCLUSION OF THE INITIAL DIAGNOSIS

The first order analysis presented above adds to the plausibility of the proposed event scenario. Two complex issues remain, however. First, what piping loads were necessary to cause the actual damage? Second, the loads are directly proportional to the assumed slug velocity. The slug was accelerated by the condensate pump, which is coupled to the rest of the condensate system as well as the #3 feedline. What was the actual velocity of the slug at the instant of impact?

Both issues are addressed in the confirmation stage.

3.6 Confirmation

PIPING LOADS ESTIMATED FROM OBSERVED DAMAGE

The piping support vendor thoroughly inspected the damaged components. An estimate of the waterhammer forces was obtained by stress analysis. The force was estimated at 80,000 lb_f, which is in reasonable agreement with the the first order calculations. More elaborate fluid transient analysis of the event (see below) also predicts forces in this range.

FLUID TRANSIENT ANALYSIS

Numerical simulations of the fluid transient were performed to gain a better understanding of the event. They provide more precise estimates of piping loads by simulating all important elements of the fluid system. The primary uncertainty addressed by these analyses is the fluid column velocity at the instant of the vapor cavity collapse. They also allow a range of possible scenarios to be simulated, indicating which sequence of events results in large piping loads.

The fluid transient analysis program uses the Method of Characteristics to calculate compressible flow phenomena such as waterhammer. The program is able to account for column separation, to calculate the transient behavior of vapor cavities, and to calculate the pressure transients when the cavities collapse. The program constructs a specific piping system from a library of basic components. Fixed points in the system are computational nodes, while node–connecting elements are components such as pipes, pumps, valves, strainers, etc.

The model for the condensate and feedwater system in this case is illustrated in Figure 3.5. Boundary conditions are closed valves or reservoirs such as the #3 steam generator or the condenser. Both AFW systems, which were operating throughout the transient, are included in the model. Node "23E" is indicated in the Figure. Calculated parameters from the location (just upstream of the BF22 check valve) will be presented below.

Some of the major results of the analysis are presented in Figures 3.6 and 3.7 The vapor cavity volume on the condenser side of the BF22 stop/check valve (node 23E) is shown in Figure 3.6 as a function of time. (In the simulation the steady blowdown from the steam generator was modeled for only a few seconds; the BF22 valve closes abruptly at t = 4 s in the Figure). The calculated cavity reached a maximum of about 2 ft^3 approximately 1 second after the check valve slammed shut. The cavity then collapsed and generated a pressure spike

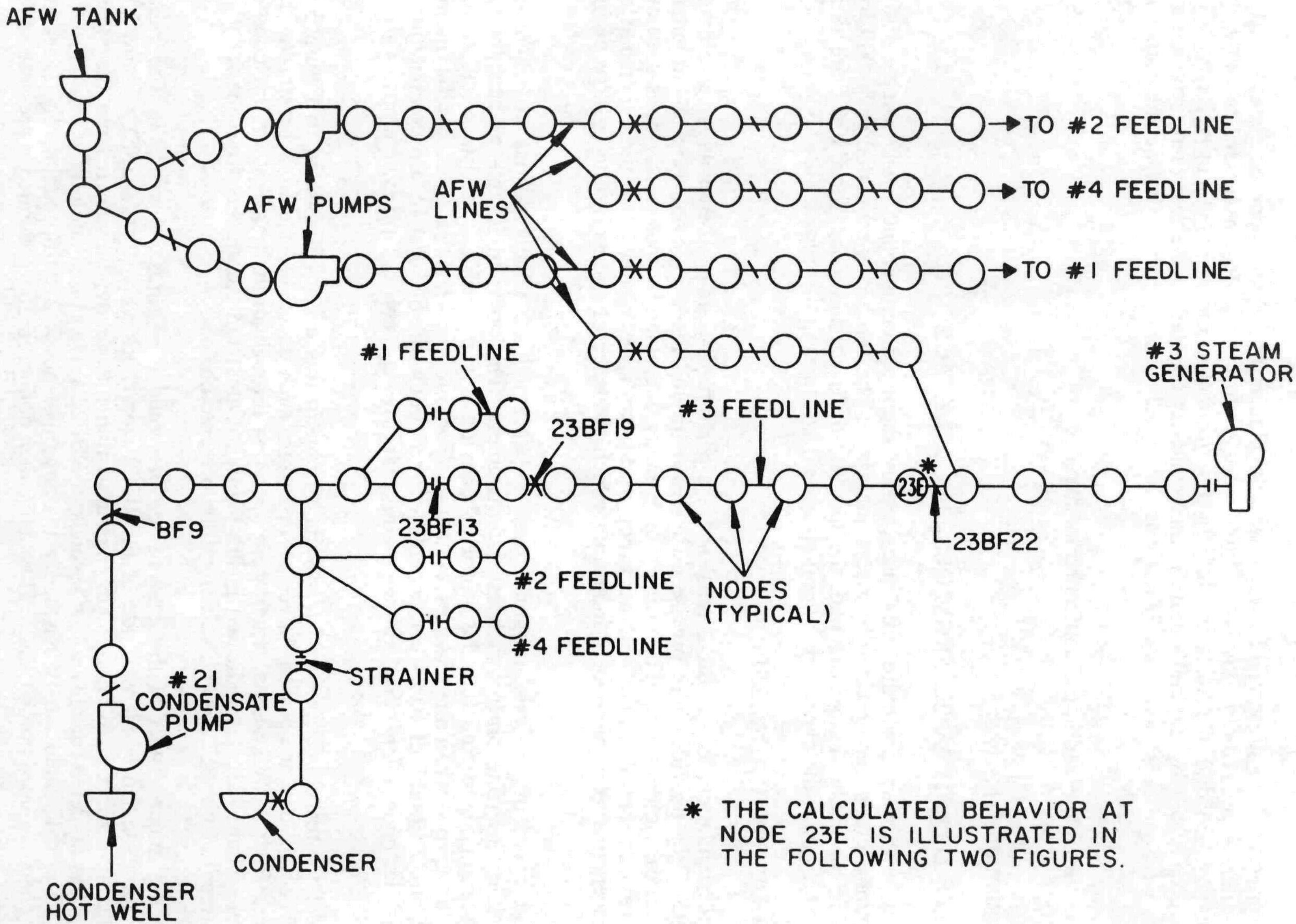


Figure 3.5 COMPUTATIONAL MODEL OF THE CONDENSATE, FEEDWATER AND AUXILIARY FEEDWATER SYSTEMS

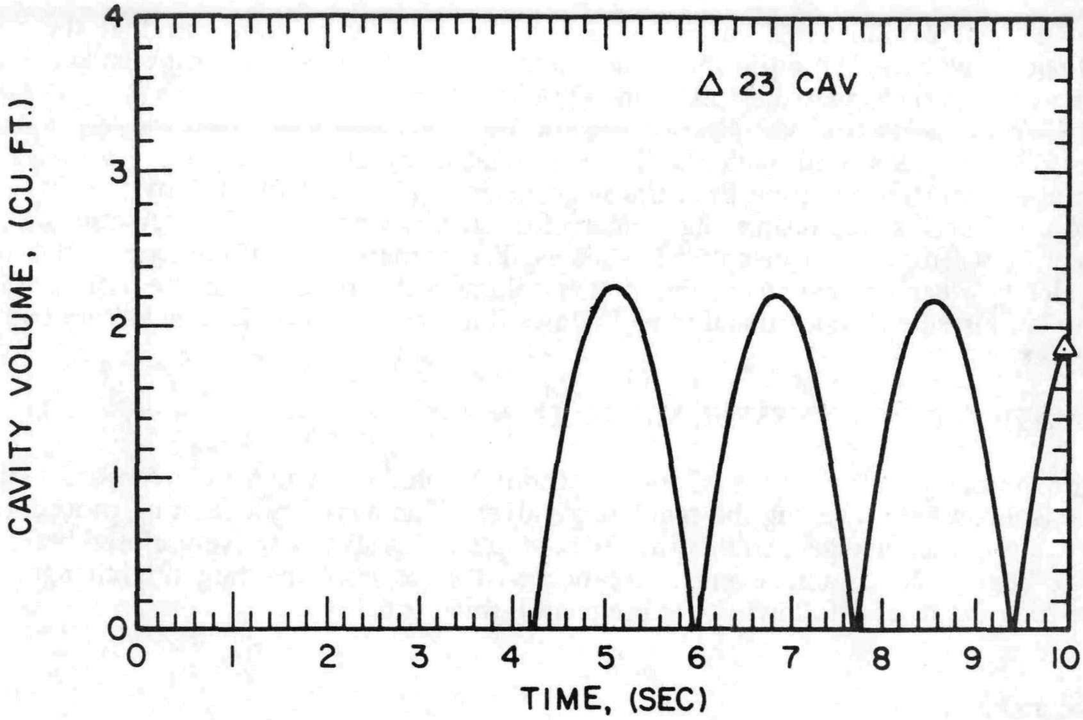


Figure 3.6 CALCULATED CAVITY VOLUME UPSTREAM OF THE BF22 STOP/CHECK VALVE

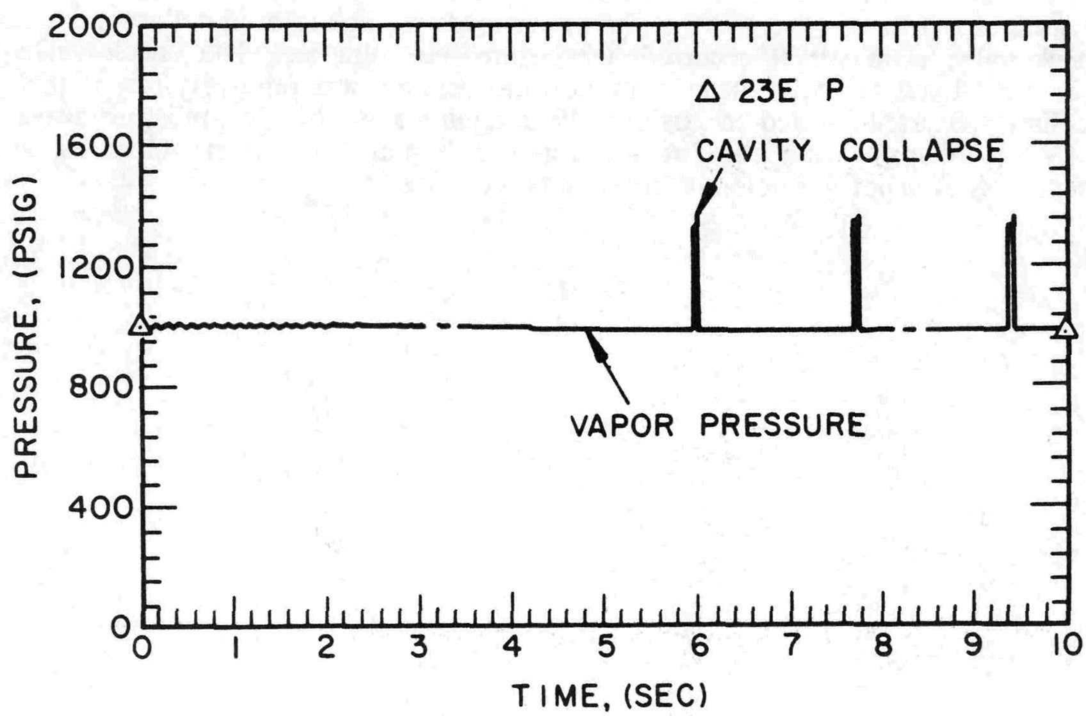


Figure 3.7 CALCULATED WATERHAMMER PRESSURE DUE TO CAVITY COLLAPSE

of about 400 psi, as illustrated in Figure 3.7. The calculation indicates that the cavity oscillated due to wave reflection in the feedline, generating a series of pressure spikes. Axial piping forces due to these pressure spikes are 62,000 lb_f.

This piping load agrees well with the force estimated by stress analysis. However, the pressure surge calculated with the fluid transient code is half that estimated by the first order calculations. This is reasonable agreement for such scoping level calculations. The discrepancy between the two calculated loads is due primarily to differences in the water column velocity when the cavity collapsed (the column velocity is less in the transient code calculation because the computational model allows fluid to flow from the condensate pump to the condenser).

CONFIRMATION BY SUCCESSFUL MITIGATION

This waterhammer problem has a simple procedural solution, which is to ensure that the feedline is isolated before testing the regulating valves. The auxiliary operating procedures at this plant were in fact changed, so that the BF22 stop/check valve is actively closed before the stroke tests begin. No similar events have occurred since implementing this change, even when restarting the reactor following a subsequent turbine trip.

3.7 Discussion

This is yet another case where failure of a check valve results in unanticipated flow conditions, ultimately causing waterhammer. As a general rule, waterhammer investigators should always question the operation of check valves when evaluating an event scenario.

An interesting aspect of this event is that the major loads are due to void collapse, and not the BF22 check valve slam which occurred just before the collapse. The check valve slam resulted in small loads for two reasons: 1) the fluid velocity was relatively low (4,000 gpm) and 2) column separation acted to cushion the magnitude of the low–pressure wave even further. Void collapse was driven by the condensate pump at higher velocities, and no cushioning effect of vapor formation occurred upon collapse.

4 TRAPPED VOID COLLAPSE IN A PWR CONDENSATE SYSTEM

This waterhammer occurred due to trapped void collapse upon startup of the condensate pumps. The void was formed due to heat transfer from the blowdown heat exchanger.

4.1 Purpose of This Case

This case is included to:

1. Illustrate void formation by active heat transfer, and

2. Illustrate the extent of piping motion which can occur due to waterhammer in unrestrained piping systems.

4.2 System Description

CONDENSATE SYSTEM

A schematic of the condensate system is shown in Figure 4.1. The system consists of the condenser, condensate pumps, several heat exchangers, the condensate storage tank and the associated piping and valves. During normal operation the three condensate pumps take suction from the condenser hot well. Condensate temperature is about 100°F. Each pump has a rated capacity of 8250 gpm with a discharge pressure of 215 psig. After passing through the steam jet air ejector condensers and the gland steam condensers, condensate is pumped through five demineralizers and then through a series of low pressure feedwater heaters. The heated condensate flows to the three condensate booster pumps which provide suction to the main feedwater pumps.

A small fraction of the condensate flow is pumped through a parallel path to cool the steam generator blowdown heat exchangers. Downstream of the gland steam condenser an 8 inch condensate pipe (8"GB14–1080) carries cool condensate to the tube–side of the blowdown heat exchanger. An isometric drawing of this line is shown in Figure 4.2. Roughly 300 gpm of condensate flows through each blowdown heat exchanger. After cooling the steam generator blowdown, the heated (140°F) condensate is routed directly to the condensate storage tank. The pipes leading to and from the heat exchanger are long horizontal runs (several hundred feet each) which are not seismically restrained. Their supports are designed to handle dead weight only.

STEAM GENERATOR BLOWDOWN RECOVERY SYSTEM

The steam generator blowdown recovery system (SGBRS) treats blowdown from the steam generators to meet chemical specifications. A schematic of this system is presented in Figure 4.3. The system consists of the steam generators, blowdown heat exchangers, mixed bed demineralizers, piping, valves and controls. Liquid blowdown from each steam generator is cooled from 500 to 120°F in a blowdown heat exchanger (BDHX). There is one BDHX for each steam generator. The cooled blowdown liquid is then routed through mixed bed demineralizers and flows to the condenser.

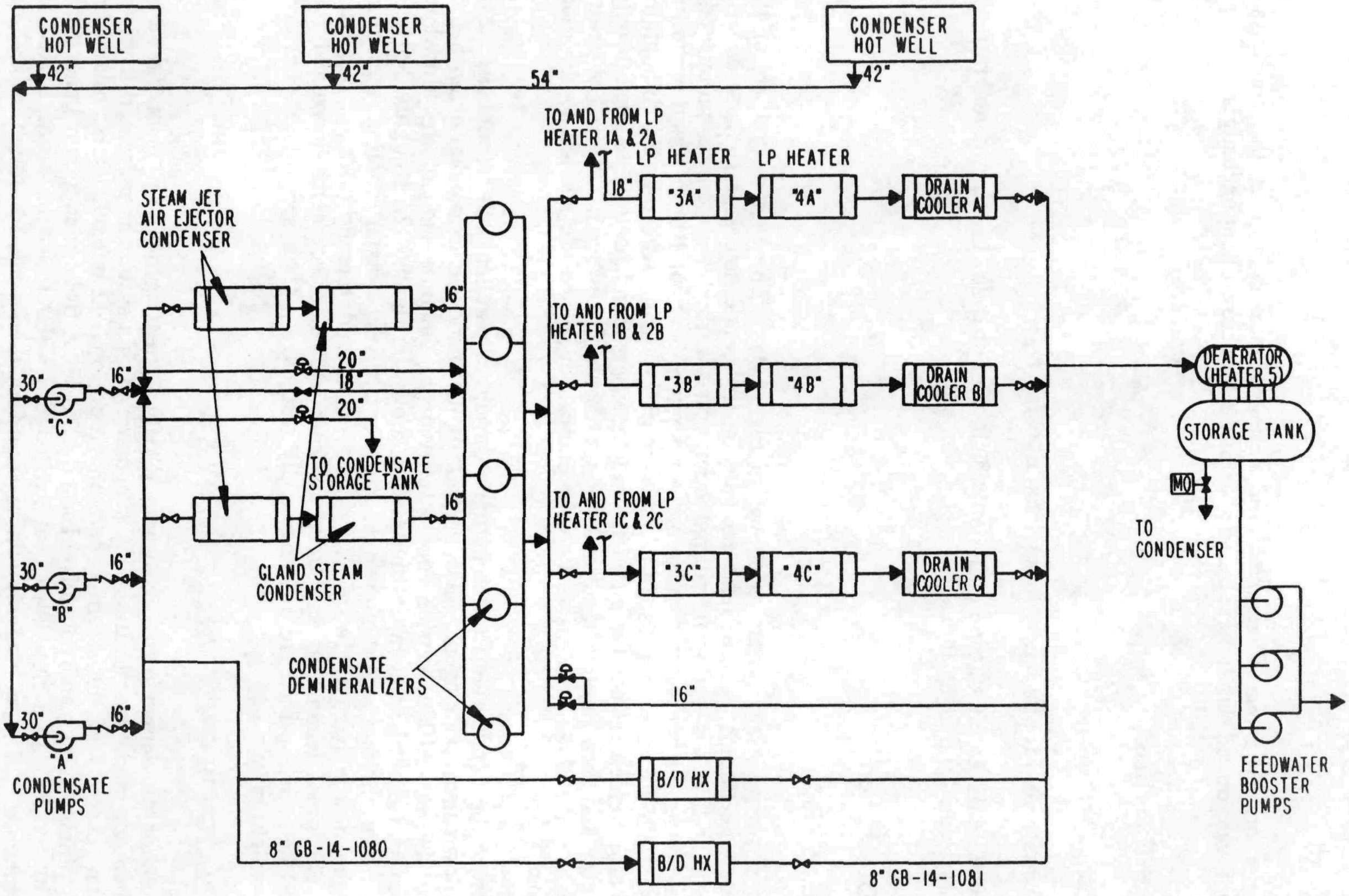


Figure 4.1 CONDENSATE SYSTEM FLOW DIAGRAM

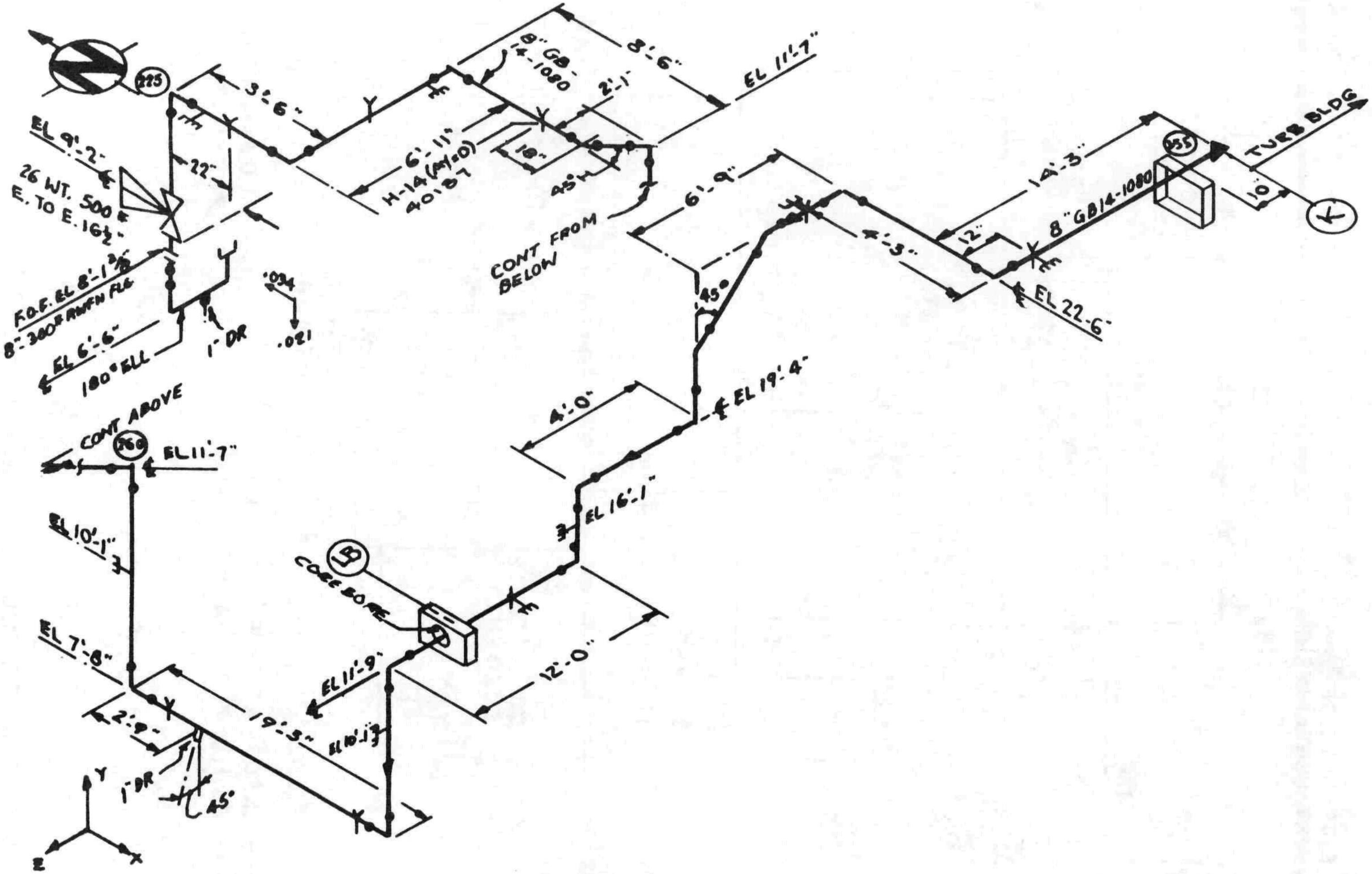


Figure 4.2 ISOMETRIC OF BLOWDOWN HEAT EXCHANGER INLET LINE

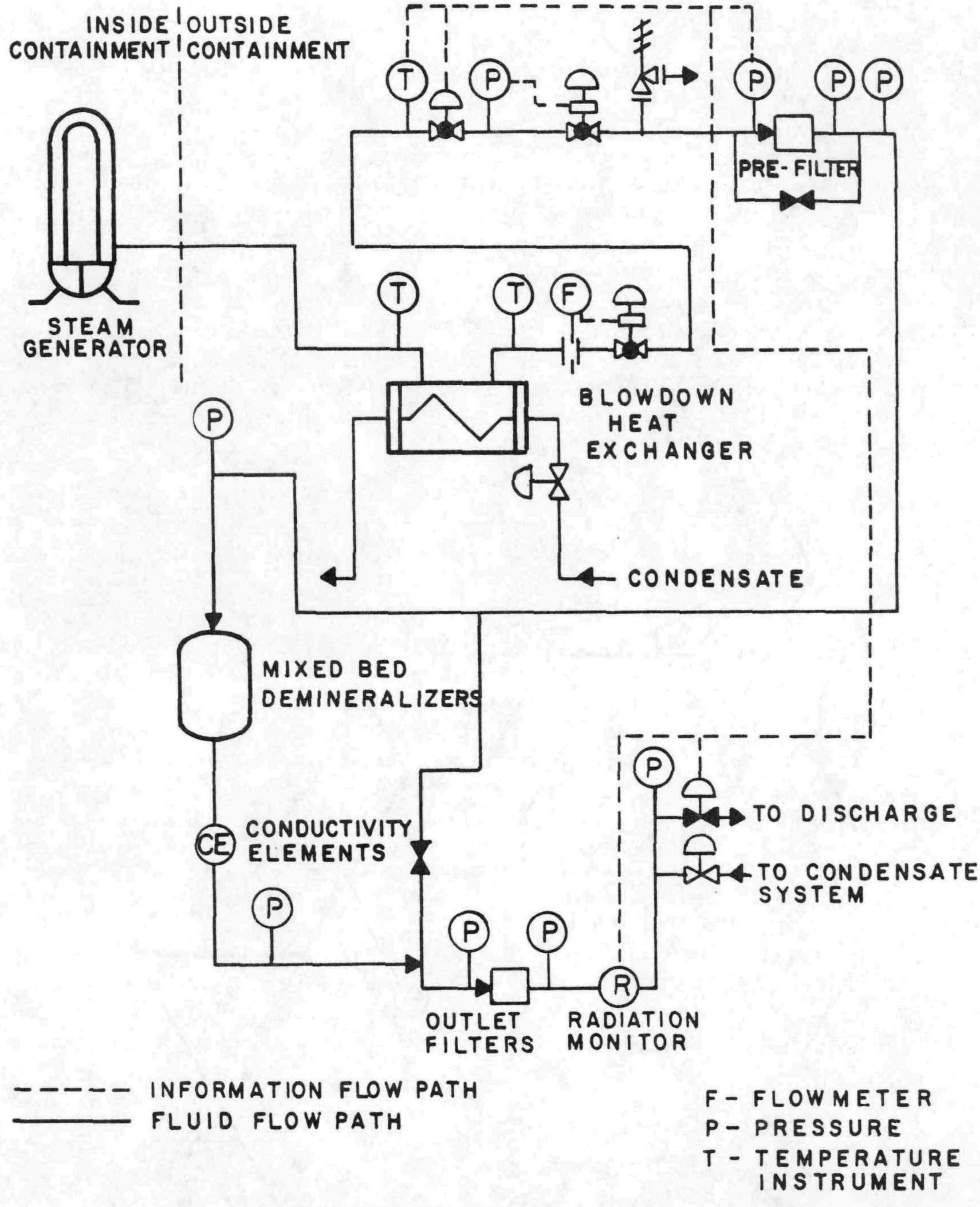


Figure 4.3 STEAM GENERATOR BLOWDOWN RECOVERY SYSTEM FLOW DIAGRAM

Whenever the steam generators are in service, it is normal operating practice to maintain 40 to 50 gpm of flow through the blowdown recovery system.

4.3 Sequence of Events Leading to Waterhammer

Prior to the waterhammer, the plant was in Mode 3 (hot standby) at normal operating temperatures and pressures. The A and C condensate pumps were running, but the B pump was shut down for maintenance on its suction line expansion joint. After the joint had been successfully repaired, operators prepared to restart the B condensate pump. To bring the pump back into service, operators first attempted to open the B pump's discharge valve. They found that the valve was stuck and would not open.

The valve was stuck because there was a large differential pressure across it. This differential pressure existed because the two operating pumps pressurized the discharge header to 215 psig. Operators stopped the operating condensate pumps to eliminate this differential pressure so the B discharge valve could be opened. Once all the condensate pumps were stopped, operators sucessfully opened the B discharge valve.

The procedure was then begun to restart all three condensate pumps. This involves starting one pump at a time with the discharge valves open. Approximately 15 minutes after all the condensate pumps were shut down, operators started the A pump. Almost immediately after the A pump began to run, a waterhammer occurred.

An equipment operator who was in the turbine building at this time witnessed the effects of the waterhammer on the 8 inch inlet line to the blowdown heat exchanger. The operator reported lateral pipe motion of "four to five feet." A nearby fire sprinkler line was hit by the moving inlet line. The sprinkler line broke and began to spray water.

4.4 Description of Damage

Damage from this event consisted of the broken sprinkler line and several damaged pipe supports.

The most severe damage occurred in the heat exchanger inlet line. A section of the 8 inch inlet line runs parallel to a 4 inch fire main in the lower levels of the turbine building. The lines are two feet apart for a run of about 20 feet. The eight–inch inlet line suffered such violent motion during the waterhammer that it struck the fire main at high velocity. The fire main broke and sprayed out a large amount of water.

Six hangers were damaged and needed repair. Also, several pipe saddles were pulled axially out of their hangers.

4.5 Event Diagnosis

EVENT CENTER

There are two conceivable mechanisms for void formation in this case. One is drainage of the blowdown heat exchanger lines into the condensate storage tank. However the elevation of the condensate storage tank inlet is above the piping where the damage occurred. Thus the void could not have formed by gravity–driven drainage.

The other mechanism is heat transfer from the shell side of the blowdown heat exchanger. Since the shell side is quite hot (350°F) and the tubes are at relatively low pressure this seems reasonable. Scoping analysis (see below) indicates that the water in the tubes would indeed boil when the pumps were shut down.

FLUID STATE

The fluid pressure in the BDHX piping is low prior to the event, since the condensate pumps are shut down and the pipe is open to the condenser. Steam which is created in the heat exchanger tubes rises out of the heat exchanger and probably collects in the raised section of outlet pipe just above the heat exchanger (see Figure 4.4). The void is limited to sections of pipe above el. 6"6', which is the inlet line elevation. Additional heat tranfer into the steam void beyond this point would raise its temperature but not result in any net fluid flow due to thermal stratification of the liquid interfaces (Figure 4.4).

EVENT SCENARIO

Based on the above considerations, the following event scenario is proposed:

1. Void Formation

When the condensate pumps are tripped to relieve the differential pressure on the B pump discharge valve, the pressure in the condensate line to the BDHX and inside the heat exchanger tubes is greatly reduced. The hot blowdown fluid on the shell side of the BDHX boils the fluid in the tube and generates a hot steam void as illustrated in Figure 4.4.

2. Slug Formation

The liquid slug consists of the condensate liquid already in the heat exchanger inlet line.

3. Slug Acceleration

The slug is accelerated when the A condensate pump is activated.

4. Void Collapse

As the condensate from the inlet line is accelerated, the hot interface which bordered the steam void is disrupted. Rapid condensation occurs on the cool condensate from the inlet line. The steam provides little cushioning effect, and the slug acceleration and impact is goverened primarily by the pump startup dynamics.

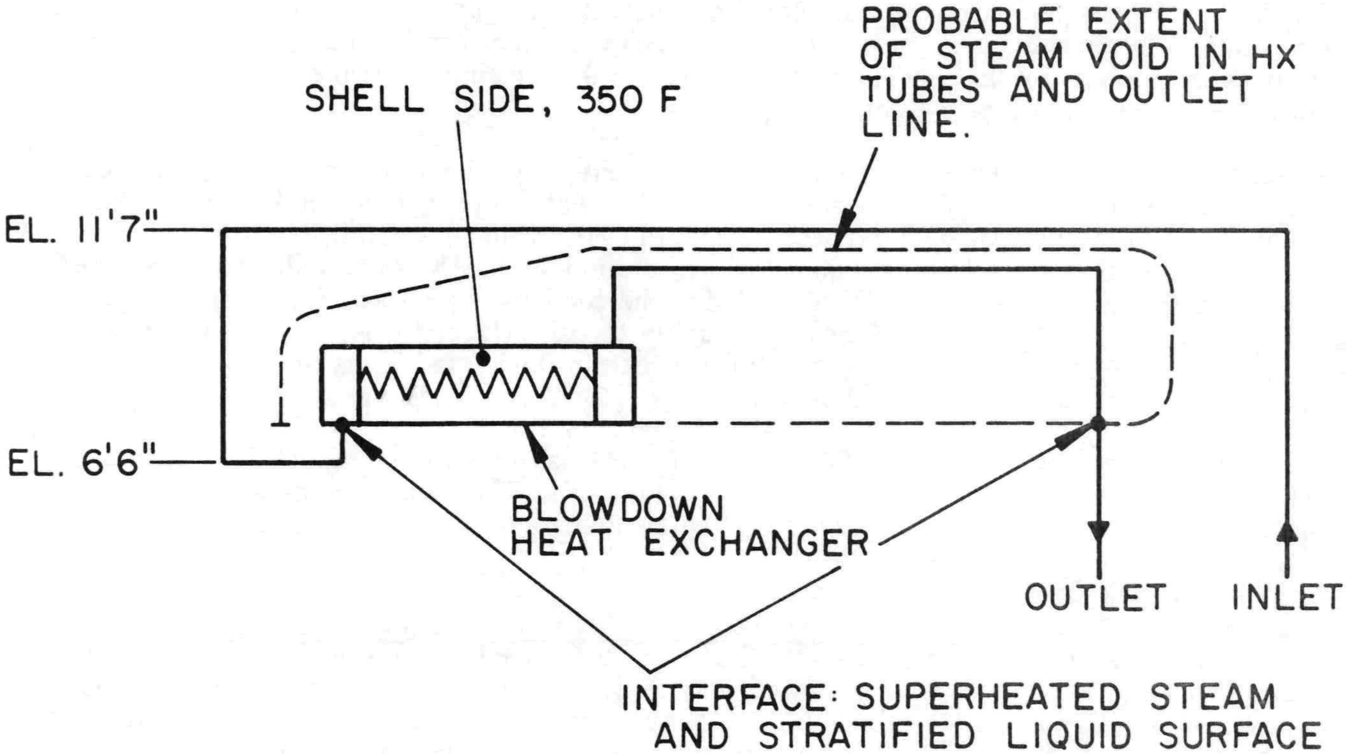


Figure 4.4 VOID FORMATION IN THE BLOWDOWN HEAT EXCHANGER

5. Impact

As the void disappears, the pumped liquid column strikes the stationary liquid surface in the BDHX exit line.

SCOPING CALCULATIONS

1. Void Formation

Condensate in the tube–side of the blowdown heat exchanger will boil if the shell side temperature is greater than the saturation pressure of the condensate. The saturation temperature depends on the tube–side pressure, so we must estimate the pressure in the tubes when the condensate pumps are not running.

When the condensate pumps are shut down, the pressure in the blowdown heat exchanger tubes is determined by depth of water between the heat exchanger and a known pressure boundary. The blowdown heat exchanger is at el. 9'0" while the condenser water level is estimated to be at el. 35'. Thus the tube side pressure in the BDHX is the hydrostatic pressure of a 26 foot column of water (at 100°F) added to the condenser pressure. Referring to Figure C.3 in Volume 1, the hydrostatic pressure is roughly 11 psi. The condenser liquid surface is at the saturation pressure corresponding to 100°F, which is 0.96 psia. Thus the pressure in the BDHX tubes is about $11 + 0.96 \approx 12$ psia..

The shell–side temperature of the BDHX is 350°F. The saturation pressure of 350°F saturated water is well over 100 psia (see Figure D.1, Volume 1). Thus the tube pressure following shutdown of the condensate pumps (24.7 psia) is low enough to permit boiling in the tubes.

2. Waterhammer Overpressure

The waterhammer overpressure due to the impact of a pumped column of liquid is estimated using Figure C.8 in Volume 1. For a scoping analysis it is sufficient to assume that the entire outlet from the A condensate pump initially flows through the BDHX inlet lines. This is reasonable because the initial fluid system response is dominated by inertia effects. The relatively low mass of fluid in the inlet line will be accelerated by the pump before the remaining large–diameter condensate lines are much affected.

The A pump is rated at 8250 gpm. Referring to Figure C.8, the impact overpressure due to sudden deceleration of the pumped column is approximately:

$$\Delta P_H \approx 3{,}000 \text{ psi}$$

3. Piping Loads

The piping load is estimated using Figure C.11 (Volume 1) for a waterhammer overpressure of 3,000 psi and an 8 inch pipe. The segment forces resulting from the waterhammer are roughly:

$$F_H \approx 150{,}000 \text{ lb}_f$$

This is a substantial load for a line which is not strongly supported.

CONCLUSION OF INITIAL DIAGNOSIS

The sequence of events and the piping configuration around the blowdown heat exchanger allowed a steam void to form while the condensate pumps were shut down. Rough calculations indicate large loads generated by void collapse which appear consistent with the damage and motion from the event.

4.6 Confirmation

In this case, as in many similar events of relatively low magnitude, this diagnosis is confirmed by a successful fix. After the event was diagnosed, two actions were taken to prevent void formation in the condensate piping:

1. Immediately following the event, operators were briefed on the problem and procedures were changed, and

2. Design modifications were made as a long term solution.

The procedural fix which was implemented almost immediately was as follows: Whenever the condensate pumps were shut down, operators were instructed to stop the flow of blowdown water from the steam generators to the blowdown heat exchanger. This greatly reduces the heat transfer to the condensate in the heat exchanger tubes, preventing (or reducing) the formation of steam voids. Following these procedural modifications, waterhammer in the condensate lines did not recur.

Consideration was given to modifying the design of the blowdown recovery system to prevent void formation in the condensate system. The modifcation concerns the control logic for the demineralizer bypass valve (see Figure 4.3). Modified control logic causes the bypass valve to close completely when the condensate pumps were deactivated. With the bypass valve closed, all blowdown flow from the steam generator is routed through the train of demineralizers. Since the pressure drop through the demineralizers for a given flow rate is much greater than that through the bypass lines, closing the bypass valve results in a dramatic reduction in the rate of blowdown flow. Reduced blowdown flow through the shell side of the BDHX reduces the rate of heat transfer to the condensate and prevents (or reduces) void formation.

5 TRAPPED VOID COLLAPSE IN A BWR RESIDUAL HEAT REMOVAL SYSTEM

This case illustrates that waterhammer can cause significant damage even without a single, large–magnitude event. In this case, diagnosis must proceed without indication of when the event or events actually occurred.

5.1. PURPOSE OF THIS CASE

This case:

1. illustrates a common drain–down incident in a piping system with large elevation differences (such as RHR or service water systems),

2. provides a description of a BWR RHR system, in which waterhammers occur relatively frequently,

3. illustrates the types and extent of snubber damage which can accumulate over time due to relatively minor waterhammers,

4. illustrates a diagnosis for an event whose exact time of occurrence is unknown, and

5. shows how piping system analysis can be used to support diagnosis.

5.2. SYSTEM DESCRIPTION

The major systems involved in this event are the residual heat removal system and its associated mechanical shock arresters, or "snubbers."

RHR SYSTEM

The primary purpose of the RHR system is to restore and maintain the coolant inventory in the reactor vessel following a LOCA so that the core is adequately cooled. Another important LOCA–related function is containment cooling to condense steam from a reactor vessel blowdown.

In fact, the RHR system has several secondary functions related to both routine and abnormal operation. As a result, sections of the RHR system are operated relatively frequently. The RHR pumps and heat exchangers may be used to cool the pressure suppression pool, to supplement fuel pool cooling or (in conjunction with the reactor core isolation cooling system) to remove decay heat from the reactor when the main condenser is isolated. Water may be sprayed from spargers inside the vessel head to suppress steam in the upper vessel and prevent thermal stratification within the vessel during a flooding operation. Full flow test lines are provided for periodic operability tests.

A simplified schematic diagram of the RHR system is shown in Figure 5.1. The system has three main pumps, two heat exchangers, and three main fluid loops (A,B, and C). The RHR pumps are 3–stage vertical centrifugal pumps rated at 7450 gpm at 280 feet of head. The A and B heat exchangers are shell and tube types cooled by the RHR service water system. The RHR system has fluid connections to the suppression pool, the primary recirculation loops, low pressure coolant injection ports in the reactor vessel, reactor head spray spargers, containment spray spargers, and the reactor core isolation cooling system. These other components and systems occupy a wide range of elevations within the plant, and as a result the RHR system must span vertically almost 100 feet in elevation.

A keep full system is provided to maintain the upper elevations of the RHR system full of liquid water. The keep full system consists of three pumps which discharge just upstream of the main RHR pumps. These pumps operate continuously for long periods when the main pumps are idle. The keep full pumps produce a maximum head of 65 psia, maintaining sufficient pressure to prevent drain–down of water from the upper elevations into the suppression pool.

During the period of operation prior to the discovery of waterhammer damage, the RHR system was operated frequently for suppression pool cooling. This was necessary due to steam leakage into the suppression pool across a faulty relief valve leading to the main steam line. Suppression pool cooling is illustrated in Figure 5.2. The A and B pumps are activated periodically to pump suppression pool water through both RHR heat exchangers. The cooled water then flows through the RHR distribution header and back to the suppression pool through either the full flow test line or the spray header. To prevent draindown, the full flow test valves leading back to the suppression pool are not opened until after the pumps have reached operating speed. Figure 5.2 omits several connections to additional lines in the RHR system which are isolated during pool cooling. Pipes leading to reactor head, suppression pool and containment spray spargers, LPCI injection ports and the primary recirculation loops are all joined to the RHR distribution header.

SNUBBERS

Mechanical shock arresters, or "snubbers," are provided in the RHR system (and in other systems as well) to limit the acceleration of pipes due to dynamic loads such as earthquakes or waterhammer. Approximately 350 snubbers are provided in the RHR system. A photograph of a typical snubber is presented in Figure 5.3. When installed, one end of the snubber is anchored to a fixed base, such as a concrete wall, and the other end is fastened to a pipe. The snubber is designed to allow gradual pipe motion, such as that due to thermal expansion. However, accelerations greater than 0.02 g's (7.7 inches/sec^2) are resisted up to the load capacity of the snubber.

Snubber operation is explained referring to Figure 5.4. The major components of a mechanical shock arrester are: (1) a ball screw shaft which converts linear motion of the telescoping and support cylinders into rotation of the torque transfer drum, and (2) a capstan spring wound around the support cylinder. The capstan spring transfers torque from the transfer drum to the inertia mass. At low accelerations the capstan spring does not tighten appreciably and is free to slide about the support cylinder. However, at linear accelerations of 0.02 g's or greater, the ball screw and drum attempt to impart greater angular accelerations to the inertia mass, causing the spring to tighten around the end of the support tube. This in turn blocks rotation of the ball screw, preventing linear motion of the telescoping and support cylinders.

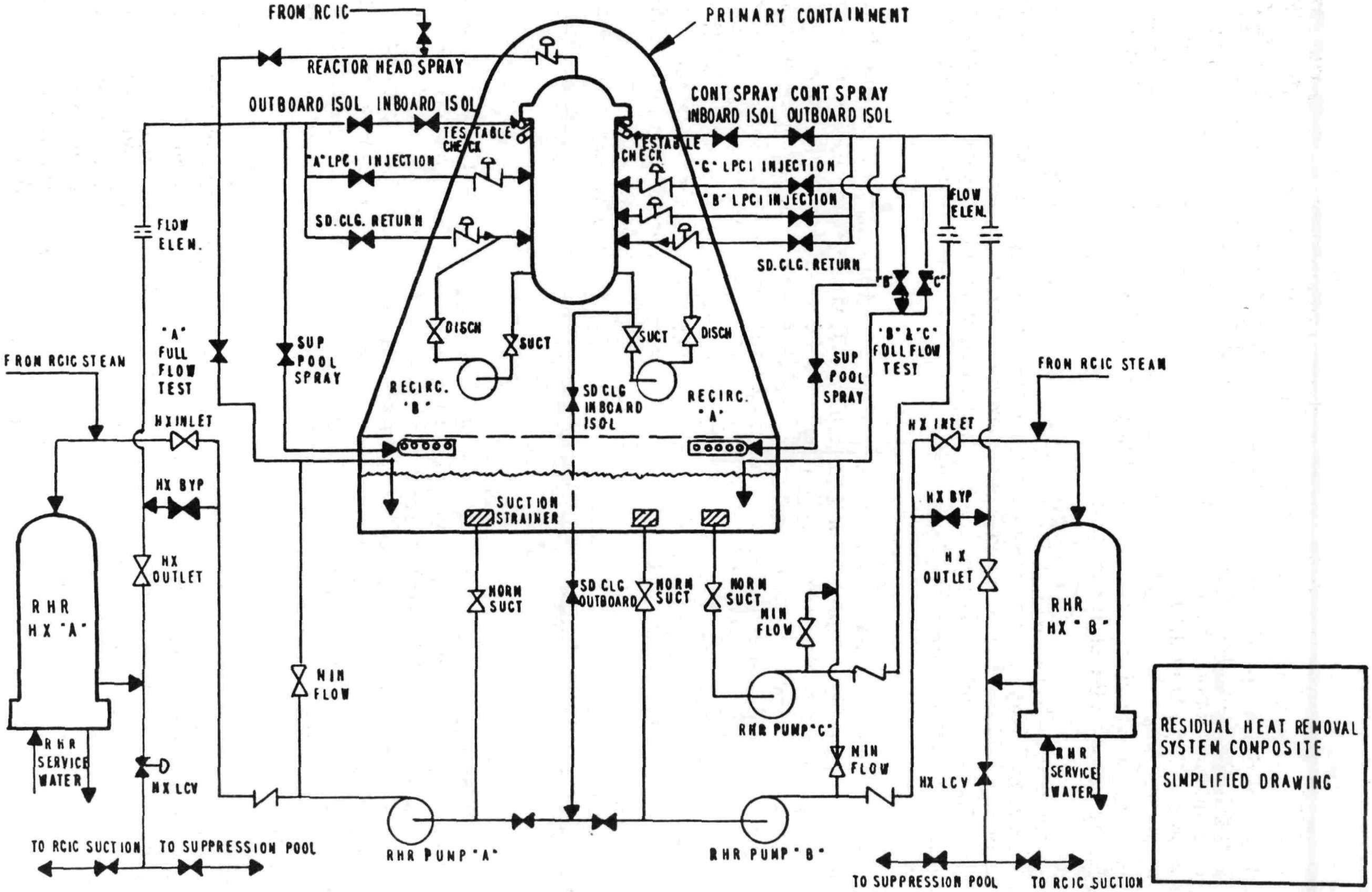


Figure 5.1 RESIDUAL HEAT REMOVAL SYSTEM

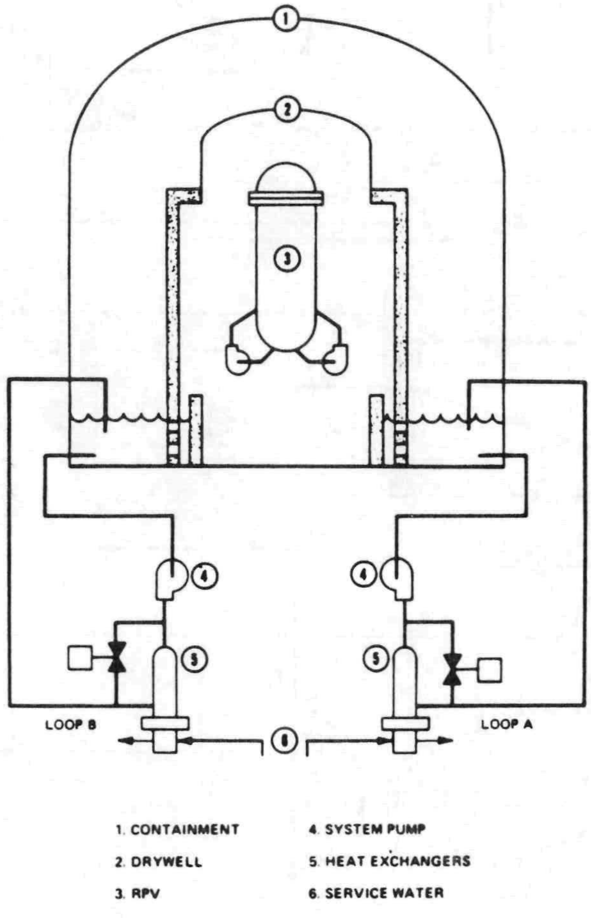


Figure 5.2 RESIDUAL HEAT REMOVAL SYSTEM, SUPPRESSION POOL COOLING FUNCTION

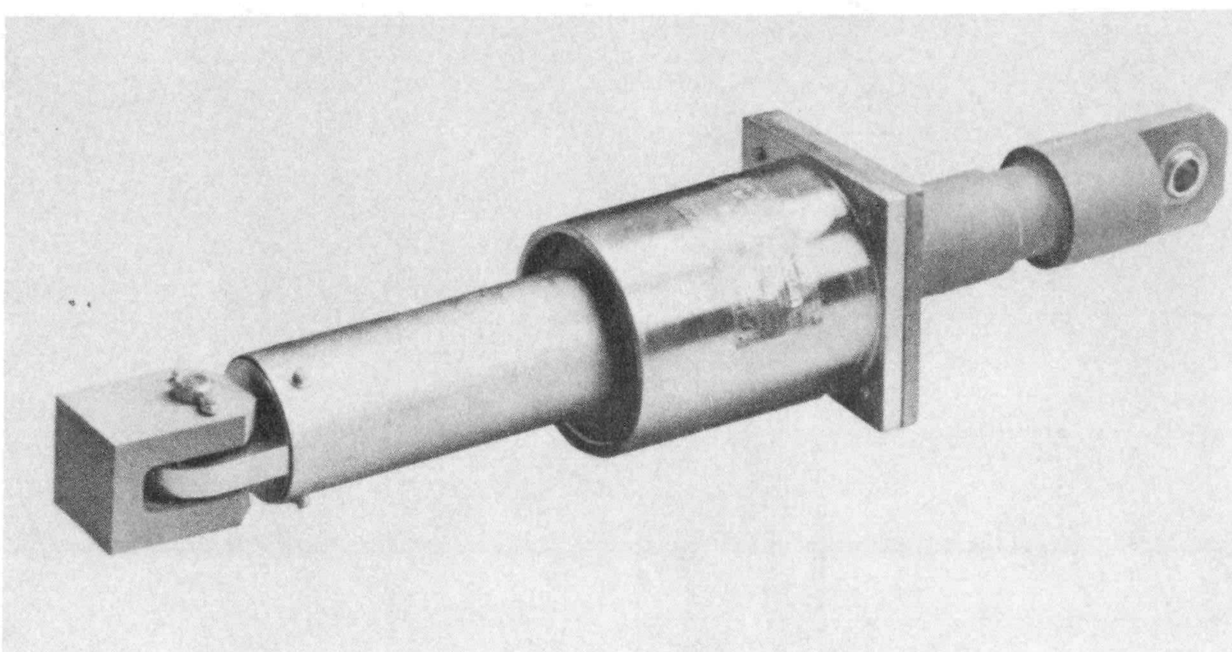


Figure 5.3 MECHANICAL SHOCK ARRESTER

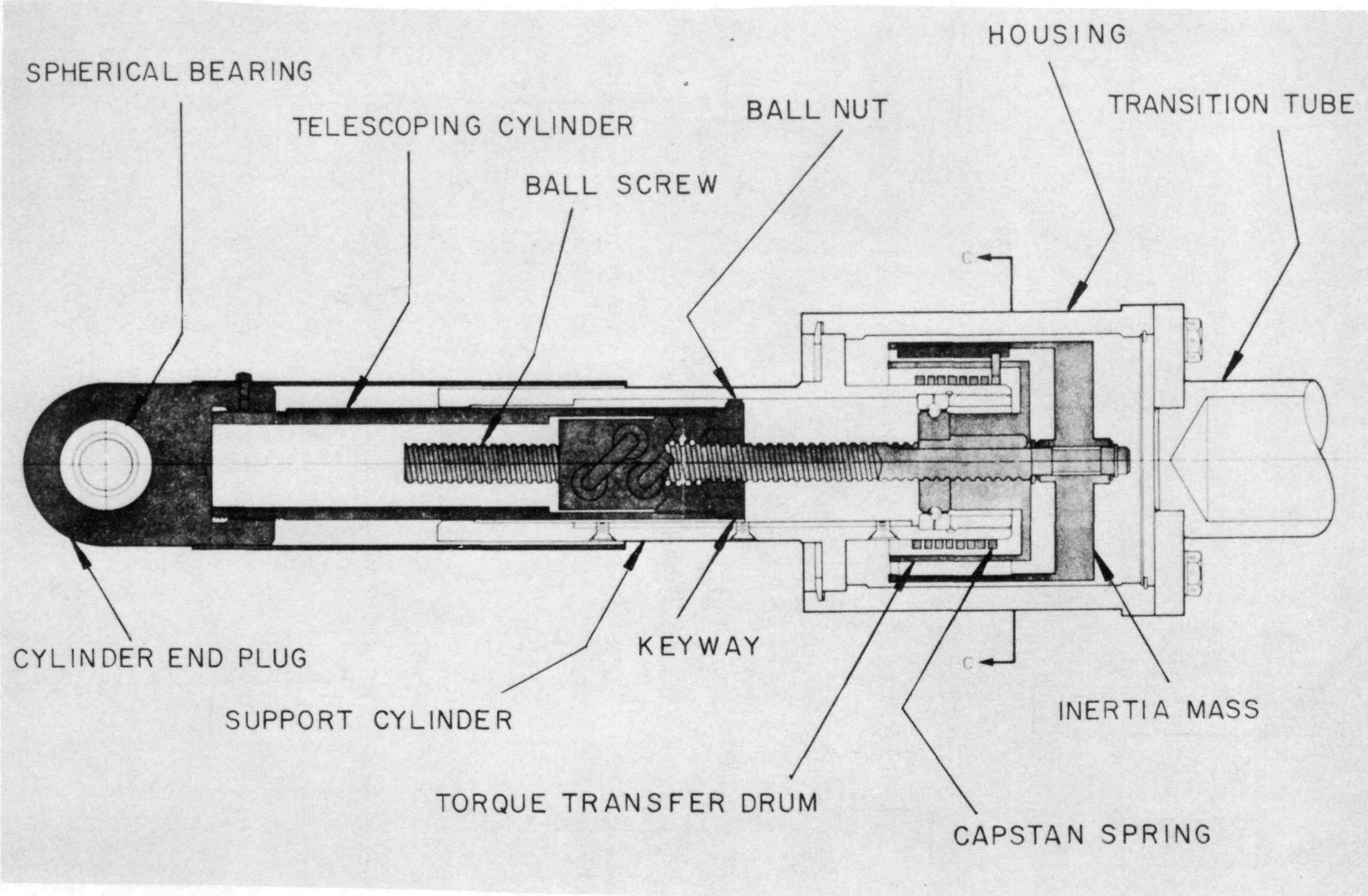


Figure 5.4 CROSS SECTION OF MECHANICAL SHOCK ARRESTER

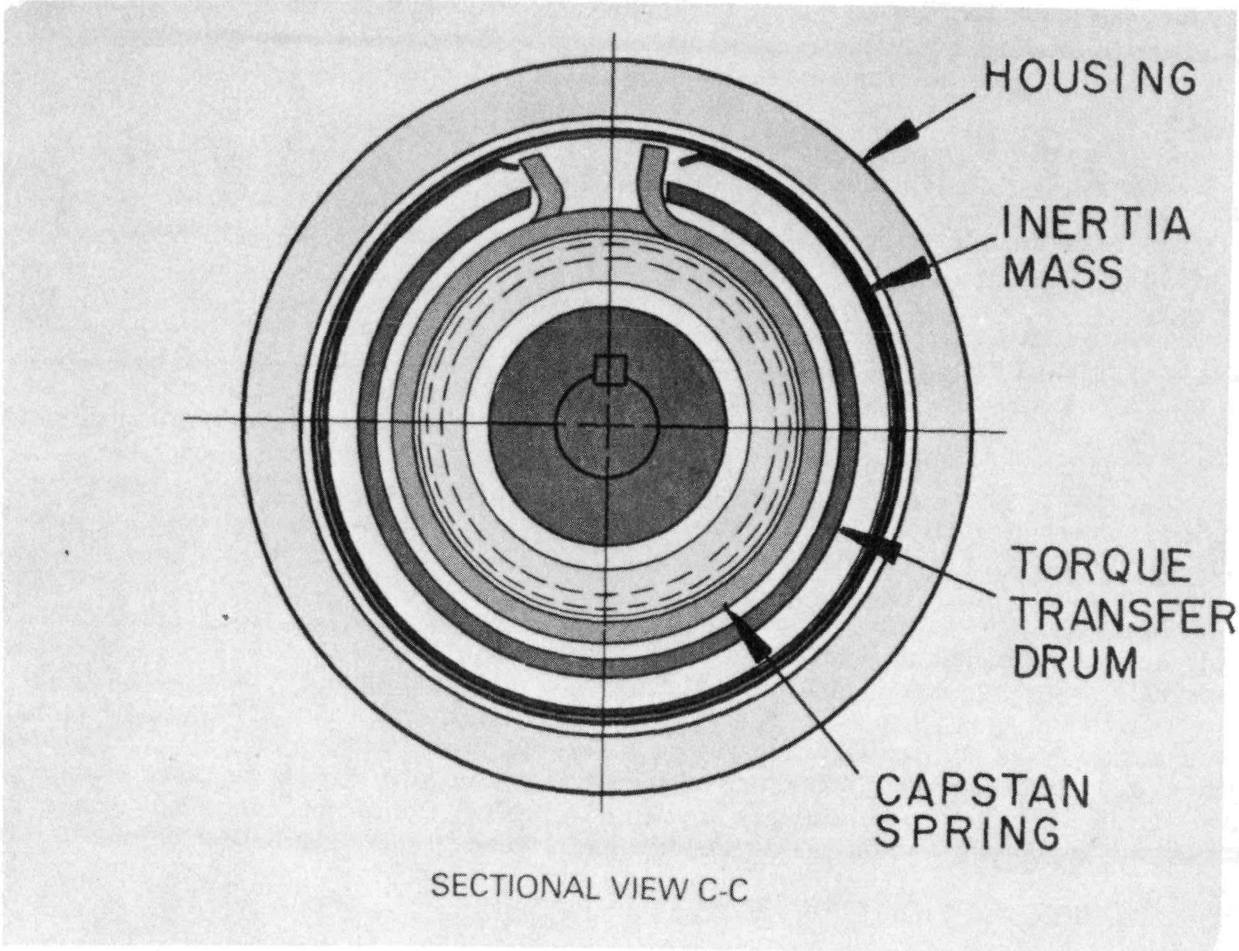


Figure 5.4 CROSS SECTION OF MECHANICAL SHOCK ARRESTER, CONT'D

The snubber mechanism is complex and prone to deterioration in performance. Possible causes of failure are manufacturing defects, improper installation, steady state vibration, excessive seismic loads or a fluid transient. Snubbers are selected with a maximum load rating determined by seismic analysis of the piping system. In the RHR system in which this waterhammer occurred, snubbers are rated between 1,500 and 50,000 pounds.

5.3. SEQUENCE OF EVENTS LEADING TO WATERHAMMER

Unlike most waterhammer events, the time of this event (or events) is unknown. The occurrence of a fluid transient was deduced after the fact based on the results of routine snubber inspections.

Plant technical specifications list operability of snubbers in safety related systems (such as the RHR) as a limiting condition for operation. Operability is demonstrated by periodic tests. Routine snubber tests are carried out using a computerized test stand which measures (1) the compression and tension forces necessary to move the snubber, and (2) the maximum acceleration attained by the snubber in response to a large load. A snubber is inoperable if the forces necessary to start motion are greater than 5% of the rated load, or if accelerations outside the range of 0.001 to 0.02 g's are measured during the activation test. Any snubber which fails to meet these criteria is disassembled and examined to determine the cause of failure.

During a refueling outage at Unit 1 of a BWR station, routine snubber tests were performed for the RHR system piping. About ten percent (35) of the RHR snubbers did not satisfy the above test requirements. The failed snubbers were taken apart and examined. Some failures were found to be due to manufacturing defects, corrosion, or dirt and/or debris. Others failed due to steady state vibration near the heat exchanger inlet. However, 14 of the failed snubbers had severe internal damage indicating a "massive overload." Since no earthquakes occurred since the last snubber inspection, it is concluded that a waterhammer must have occurred.

5.4. DESCRIPTION OF DAMAGE

Some of the snubber damage reports which indicate severe internal damage are presented in Table 5.1. (The snubber components described in the damage reports are illustrated in Fig. 5.4.) The locations of the severely damaged snubbers are indicated on piping isometric diagrams in Figures 5.5 and 5.6. Following the snubber inspections, piping in the adjacent RHR subsystems was inspected but no further damage was found.

5.5. WATERHAMMER DIAGNOSIS

EVENT CENTER

Examination of the RHR system drawings indicates two potential event centers: high points in the system and horizontal pipes. System high points are the most likely candidate for the event center.

TABLE 5.1 SNUBBER DAMAGE REPORTS INDICATING MASSIVE DYNAMIC OVERLOAD

SNUBBER LP–1054S (RATED AT 1,500 LB)

"Snubber failed to meet drag force acceptance limits. Snubber lead screw bent 1/2". Dismantled snubber showed thrust bearing was cracked into several pieces. End of the lead screw was flared where it rammed into the dust cover. Clear indication of excessive overload."

SNUBBER RH40–1572S (RATED AT 6,000 LB)

"Snubber found locked almost rigid and severely damaged. Snubber could "ratchet" freely over 1" when found in field – no force needed to stroke. Internals thoroughly destroyed, lead screw shot through dust cover 1/2". Thrust bearing smashed in pieces. Screw shaft stripped and damaged from being thrust forward through other internals. Massive overload indicated."

SNUBBER RH40–1544S (RATED AT 6,000 LB)

"Snubber failed to meet drag and activation limits because it was severely damaged internally. Unit would ratchet 1" without restraint from cold set in compression. Major transient load has bent the ball screw shaft and completely stripped threads off of snubber lead screw inner race."

SNUBBER RH59–1056S (RATED AT 15,000 LB)

"Snubber found locked rigid. Unit was forced with 4200 lbs compression and 4000 lbs tension and remained rigid. Dismantled snubber showed severe internal damage. There were dents in dust cover, broken retaining ring, damaged washers, damaged races and the screw shaft was bent 1/2" with threads stripped. Massive overload indicated."

SNUBBER RH40–1554S (RATED AT 15,000 LB)

"Snubber failed to meet drag force acceptance limits. Snubber severely damaged internally by transient overload. Snubber only partially torn down at this time—the process is extremely difficult because internals are so severely damaged."

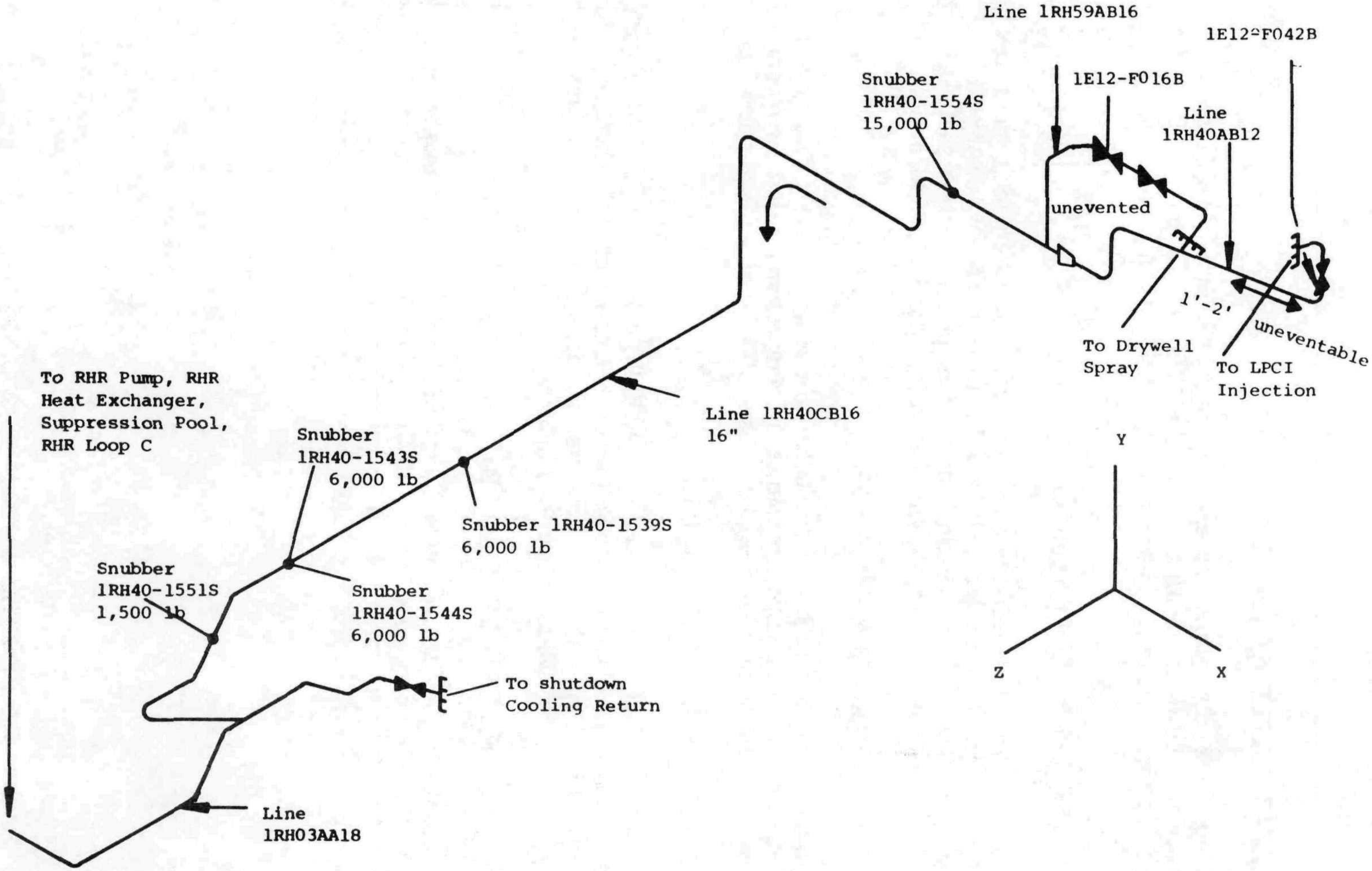


Figure 5.5 PARTIAL ISOMETRIC OF SUBSYSTEM 1RH-08

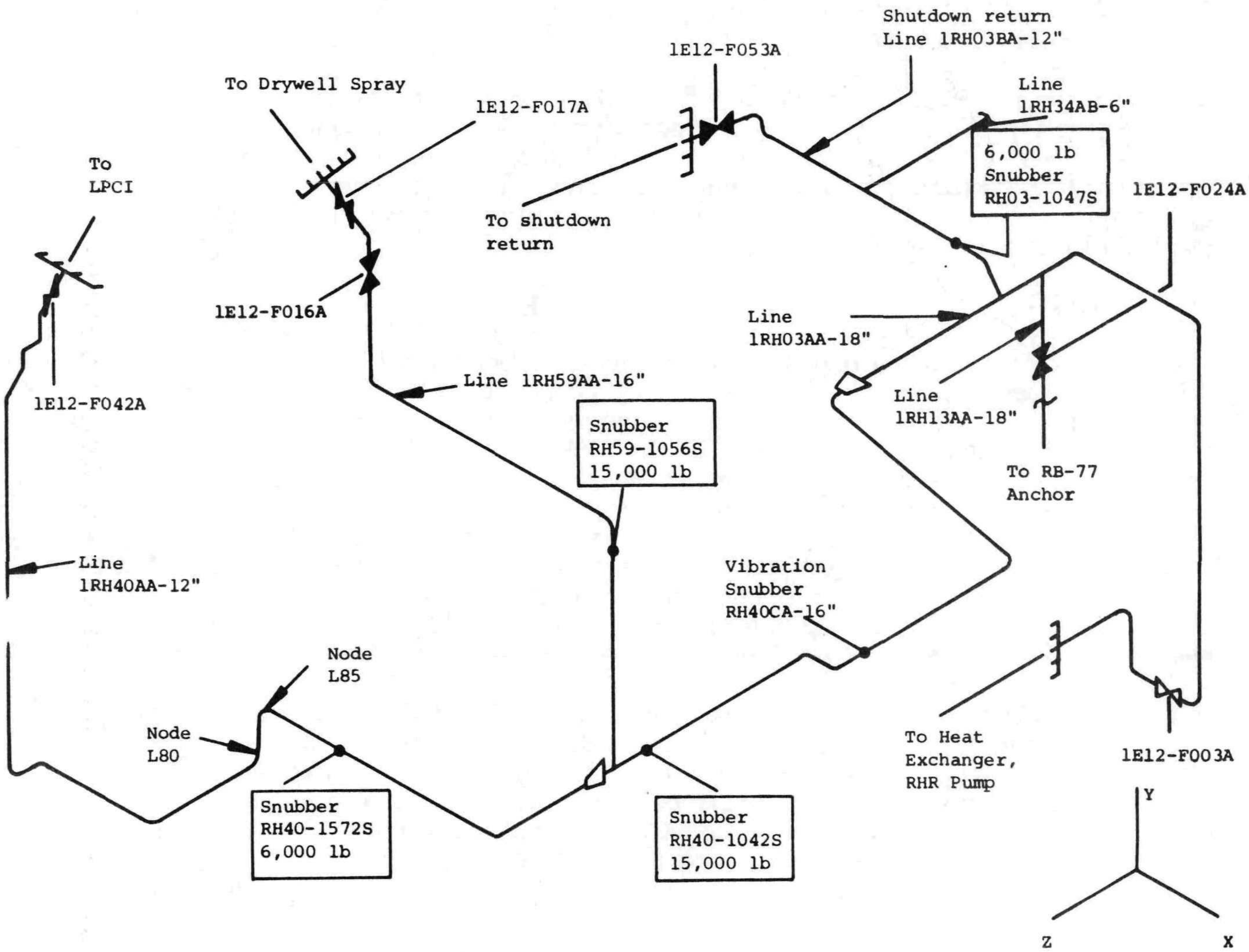


Figure 5.6 PARTIAL ISOMETRIC OF SUBSYSTEM 1RH–24

The RHR system has several stretches of horizontal pipe, some of which are shown in Figures 5.5 and 5.6. However, a subcooled water slug event in one of these pipes is unlikely for several reasons. First, such an event requires a steam reservoir which is unavailable in the RHR system. Second, subcooled water slug events are typically of very large magnitude. It is unlikely that such an event would not have been noticed at the time it occurred. Finally, the snubber damage is distributed over a large part of the RHR system. The maximum damage from a subcooled water slug event is typically greater than this and is found in fewer locations (for example, see Chapter 1).

High points in the RHR system are a more likely event center. Possible mechanisms are illustrated in Figure 5.7. Drain down from high elevations is a common method of void formation. Under the proper conditions, heat leakage across the isolation valves from the primary system is another potential voiding mechanism. Furthermore, these mechanisms could form several voids in the various high elevation, isolated subsystems. This could explain the low intensity and distributed nature of the damage.

FLUID STATE

The fluid state prior to and during the waterhammer is determined by 3 facts: the isolation valves are closed, the pressure is relatively low, and the isolation valves themselves are probably quite hot. Because the valves are closed there can be no steady flow near the event center. The maximum pressure possible in the RHR system (when the keep–full system is operating) is 20 psia at the upper elevations (see Figure C.3.). This is much less than the saturation pressure corresponding to the primary system temperature (about 800 psia for 500 F, see Figure D.1), so it is likely that a void forms near the isolation valves. This steam void will be at low pressure, but it may be quite hot. A hot steam void is possible if the liquid in the pipe stratifies, so that only a thin layer of very hot liquid is in contact with the steam. Unfortunately, there is no temperature or pressure data recorded from these locations in the plant.

If the keep full system is down for repairs, it is likely that the RHR system will begin to drain down. Atmospheric pressure can only support a 33 foot column of water, while the upper elevations of the RHR system are nearly 100 feet above the free surface of the pressure suppression pool. Potentially very large voids may have formed. The check valves at the pump outlets (see Fig 5.1) are intended to prevent drain down. Even though they do not seal perfectly, leakage past them is slow and a complete drain down is unlikely. There is no data available to support a definite conclusion regarding the actual liquid level in the RHR system.

In summary, it is likely that steam voids existed in the upper elevations of the RHR system. If a waterhammer occurred while the keep full system was inoperative, these voids may have been quite large.

EVENT SCENARIO

The following event scenario is postulated:

1. Void Formation

It has already been shown that a steam void could have formed in the upper elevations of the RHR system. Possible mechanisms are heat leakage across the isolation valves from the primary system, or depressurization and drain down due to failure of the keep full system. These mechanisms may have acted simultaneously.

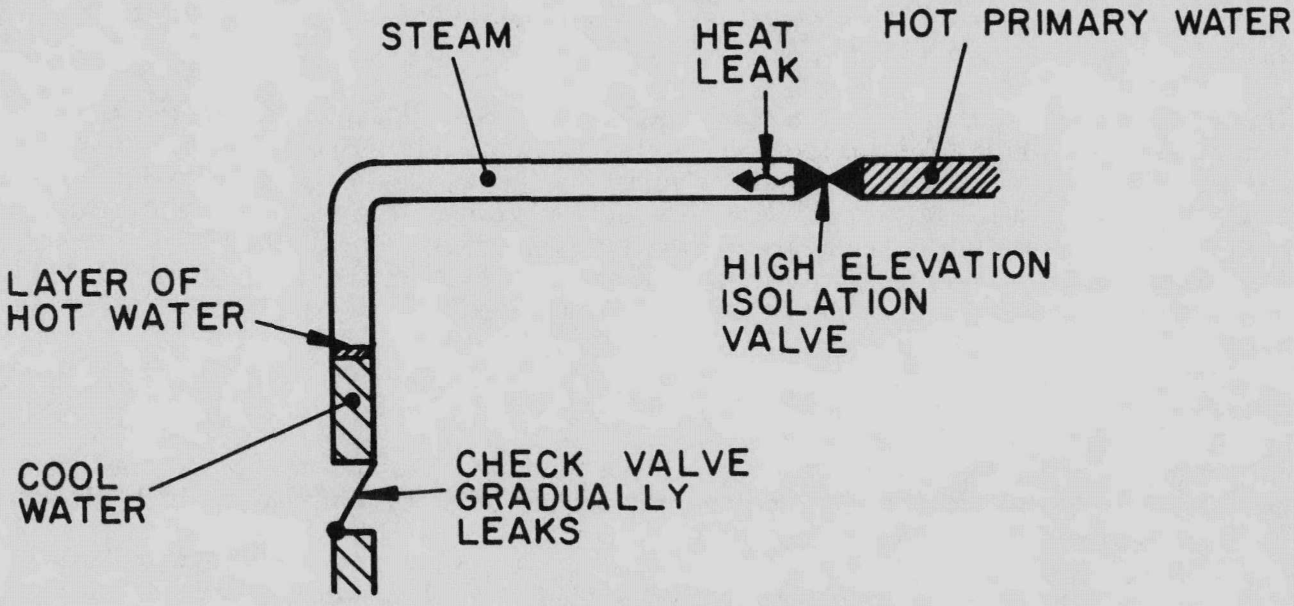


Figure 5.7 EVENT CENTER IN UPPER ELEVATIONS OF THE RHR SYSTEM

2. Slug Formation

A liquid slug exists prior to the event, consisting of the liquid column in the RHR system leading from the RHR pumps up to the voided region.

3. Slug Acceleration

The liquid slug is accelerated whenever the main RHR pumps are activated. The slug velocity is determined by pump startup procedure. The RHR pumps were activated frequently for suppression pool cooling prior to discovery of the damaged snubbers. The discharge valves (F047 – see Fig. 5.1) were not opened gradually to limit flow. It is interesting to note that all severely damaged snubbers are located in the "A" RHR system, which was exclusively used for pool cooling. In the "B" loop, which was activated much less frequently, no severe damage was found during the snubber inspection.

4. Void Collapse

The steam void above the liquid slug condensed on the rising liquid front. There are two possibilities: the void was either hot (primary system temperature) or cool. Pump activation and slug flow would disrupt any stratification in the liquid, thus bringing hot steam into contact with cool water. Rapid condensation would have occurred in this case. If the steam void were cool, it would have already been in equilibrium with the liquid slug. Pressurization of the void as the slug rises would also result in condensation. In either case, the trapped void condenses in front of the rising fluid column and results in a "hard" impact with the isolation valves.

5. Impact

The rising liquid slugs eventually reach the closed isolation valves where they are suddenly decelerated. Compression waves travel back through the RHR system, causing high piping loads and resulting in snubber damage.

Note that the detailed piping configuration shown in Figure 5.5 supports this event scenario. The moving fluid column would have split and been stopped at isolation valves F016 and F042, and two compression waves would travel through line CB16 from right to left across the Figure. As the wave travelled in the negative x–direction through the line just after the junction with RH59AB16, a force in the negative x–direction would be exerted on the long section of CB16 which lies in the z–direction leading to the four damaged snubbers (1539S, 1543S, 1544S and 1551S). The long straight section of line acts as a lever arm, amplifying the forces experienced by these snubbers. The piping configuration helps explain how damaging snubber loads could have been generated even from a moderate waterhammer which was unnoticed at the time of occurrence.

SCOPING CALCULATIONS

Scoping analysis supports this diagnosis by demonstrating the feasibility of several steps in the proposed event scenario.

Void Formation

Scoping calculations related to void formation have already been discussed in the event center diagnosis. Figure C.3 in Volume 1, which plots hydrostatic pressure versus water column height, indicates that a 100 foot column of water must be supported by over 40 psia at its base. The RHR keep full system provides this pressure when it operates. However, if the keep full system is inoperative only 15 psia (one atmosphere) is available to support the column from the free surface of the suppression pool. Thus, drain down from the upper elevations will occur if keep full system is down. Figure D.1 (Volume 1) illustrates that the pressure on the RHR side of the isolation valves (20 psia, when keep full is running) is less than the saturation pressure corresponding to the primary system temperature (800 psia). Since heat will be conducted across the isolation valve from the hot primary water, this is another possible mechanism for steam void formation.

Impact

The waterhammer overpressures resulting from the impact of the pumped water column on the RHR isolation valves is estimated using Figure C.8 in Volume 1. The capacity of the A RHR pump is 7,450 gpm, and the typical line diameter is 16". The overpressure indicated by Figure C.8 is roughly 600 psia. This is a relatively small overpressure, as is expected since these events were undetected when they occurred.

Forces on Piping

Piping loads are estimated using Figures 5.5 and C.11 (Volume 1). As an example, we will calculate the forces on snubbers 1539S, 1543S, 1544S, 1551S and 1554S. An overpressure wave of magnitude 600 psia originates when the fluid column impacts the F042 valve and travels back through lines AB12 and CB16. The force in the negative x–direction when the wave passes through AB16 is estimated at 120,000 pounds using Figure C.11. This exceeds the design loads of all these snubbers by over 100,000 pounds. Furthermore, line CB16 acts as a lever to amplify the forces experienced by the four snubbers located on the left of Figure 5.5. Snubber failure due to this mechanism is quite plausible.

Finally, it should be noted that non–condensible air is dissolved in the RHR system water and will be present to some extent in the initial voids. This air will cushion the impact of the water column on the isolation valves and reduce the severity of the waterhammer. However, studies by Papadakis (1977) have indicated that this reduction is normally no more than a factor of two. Calculated loads on the snubbers are well in excess of their rated loads even after this reduction.

In conclusion, the proposed event scenario is consistent with the available data and predicts damaging piping loads.

5.6. CONFIRMATION

The above diagnosis is partially confirmed by computer analysis. Following design and operational modifications to prevent the postulated void collapse, severe snubber damage did not recur.

Detailed analysis was performed using the HYTRAN and PIPSYS computer codes. HYTRAN is a hydraulic transient code which calculates loads assuming a fixed piping structure. The effects of these loads on the piping components is calculated using PIPSYS, a finite element structural code. In this case HYTRAN was run for assumed voids in the upper elevations of the RHR piping. Typical results of the HYTRAN/PIPSYS calculations are presented in Table 5.2. The table presents the calculated loads on various snubbers, along with the snubber load ratings. Snubbers which failed due to severe transient loads are indicated as well. The failed snubbers correspond with those whose calculated waterhammer loads exceed their rated loads. Though this analysis depends on an assumed void distribution in the RHR system, it confirms that the proposed event scenario could indeed have caused the observed snubber damage.

The RHR system design and operation were modified to prevent this void collapse. Additional vents were added at system high points and procedures modified. The new procedures call for complete venting prior to activation of the RHR pumps. Also, the flow valves just downstream of the main RHR pumps are opened gradually as the pumps are activated, reducing the initial acceleration on the water columns. Repairs to the keep full system are carried out more quickly when required. The leaking steam relief valves were repaired, reducing the frequency of suppression pool cooling operations. Following a complete operating cycle with these modifications, snubber inspection failed to reveal any damage indicating massive overload. The diagnosis and mitigation have thus been confirmed.

5.7. DISCUSSION

The key lesson from this diagnosis is the importance of limiting the rate at which water is pumped into a previously stagnant system. In the case of the RHR system, some void formation is probably inevitable due to the high temperatures of the injection valves. Procedures should call for a gradual opening of the RHR pump discharge valves (F047) after the pumps have been activated. This limits the velocity of the fluid columns on impact, thus reducing the severity of the waterhammer.

This case has also illustrated some of the general issues associated with operating the RHR system of a boiling water reactor. The RHR system provides connections between fluids with very different temperatures, pressures and elevations. As a result there are many possible mechanisms for void formation. Furthermore, the system has several modes of operation, and whenever a new mode is entered the system undergoes a transient. Thus, there are frequent opportunities to collapse any voids which might have formed. Historically, the RHR system has suffered more waterhammer events than any other single system.

5.7. REFERENCES

1 Papadakis, C.N., "Water Column Separation in Power Plant Circulating Water Systems," presented at the Third Round Table on Column Separation, E.D.F.–Bulletin de la Direction des Etudes et Recherches Serie A – Nucleare, Hydraulique, Thermique, No. 2, 1977, pp. 335–339.

Table 5.2
SUBSYSTEM: RH-08 (Partial Model)
Comparison of Snubber Capacity and Support
Load Due to 20400 Lbs. Transient

Node No.	Dir.	Support No.	PSA Size	Pressure Pulse Load (lbs.)	Rated Capacity	Comments
157	Y	RH40–1547S	3	12459	6000	
157	Z	RH40–1548S	3	5085	6000	
158	X	RH40–1549S	3	33001	6000	
195B	Z	RH03–1526S	10	6771	15000	
197	X	RH03–1525S	3	4359	6000	
212	X	RH03–1032S	10	3698	15000	
212	Z	RH03–1033S	35	3524	50000	
219	Z	RH03–1035S	35	1423	50000	
L3	**X**	**RH40–1551S**	**1**	**3532**	**1500**	**Failed**
L6	**X**	**RH40–1544S**	**3**	**20959**	**6000**	**Failed**
L6	Y	RH40–1242S	3	4448	6000	
L6	**Z**	**RH40–1543S**	**3**	**20408**	**6000**	**Failed**
L8	Z	RH40–1541S	3	4056	6000	
L9	X	RH40–1028S	3	3523	6000	
L12	Z	RH40–1029S	3	12920	6000	
L14	**Z**	**RH40–1539S**	**3**	**20382**	**6000**	**Failed**
L15	X	RH40–1540S	10	23376	15000	
L17A	X	RH40–1047S	10	7304	15000	
L19	X	RH40–1552S	10	16175	15000	
L21	Z	RH40–1048S	3	6745	6000	
L24	Z	RH40–1553S	3	5372	6000	
L30B	Z	RH40–1527S	3	5367	6000	
L31	**X**	**RH40–1554S**	**10**	**41697**	**15000**	**Failed**
L34	Z	RH40–1550S	3	7523	6000	
L51	Z	RH40–1556S	3	1791	6000	
L52	Z	RH40–1557S	35	31923	50000	
L54	Z	RH40–1558S	3	2164	6000	

6 A SATURATED WATER SLUG IN A BWR MAIN STEAM SYSTEM

This case concerns steam driven water slugs which damaged piping during the startup tests of a boiling water reactor.

6.1 PURPOSE OF THIS CASE

This case is included to illustrate a saturated water slug event.

6.2 SYSTEM DESCRIPTION

This case involves the main steam system and the main steam drain lines in a boiling water reactor.

MAIN STEAM SYSTEM

The main steam system consists of piping and valves which deliver steam from the reactor vessel to the turbine generator over a wide range of operation. A schematic diagram of the portions of the main steam system relevant to this case is shown in Figure 6.1. There are four main steam lines (A through D) each with a nominal diameter of 24 inches. Each line has two air–operated isolation valves, AOVs 6A–D and 7A–D.

STEAM DRAIN SYSTEM

The steam drain lines keep the main steam lines free of condensate by providing a drainage path from the steam lines to the condenser.

A schematic diagram of the drain line system is shown in Figure 6.1. The drain header is a 6 inch pipe (line #2MSS–6–119–1) which runs from beneath the steam line condensate drains to the condenser. Eight 2–inch lines run from the header to two locations on each of the four main steam lines. The drain connections are upstream of each of the steam line isolation valves, at low points on the steam lines so that condensate will naturally collect in the drains. The header itself runs for approximately 100 feet and empties into the condenser.

Flow in the drain header is controlled using two motor operated valves, MOV–111 and 112. An additional valve, HCV–110, is maintained in a slightly open position to function as a pressure–reducing orifice. The drain header is isolated during normal operation. Valves 111 and 112 are opened to remove condensate only during startup and shutdown operations. During condensate drainage, the partially open HCV–110 valve allows liquid to drain gradually out of the header without pressurizing the condenser. Operating procedures for the Main Steam System call for opening the MSIV drain line valves at reactor pressures of up to 950 psig. When the reactor is shut down and steam pressure is falling, the drain lines are reopened once the pressure is less than 950 psig.

The drain header is not designed for seismic loads. It is supported primarily for dead–weight loads, and has no axial support.

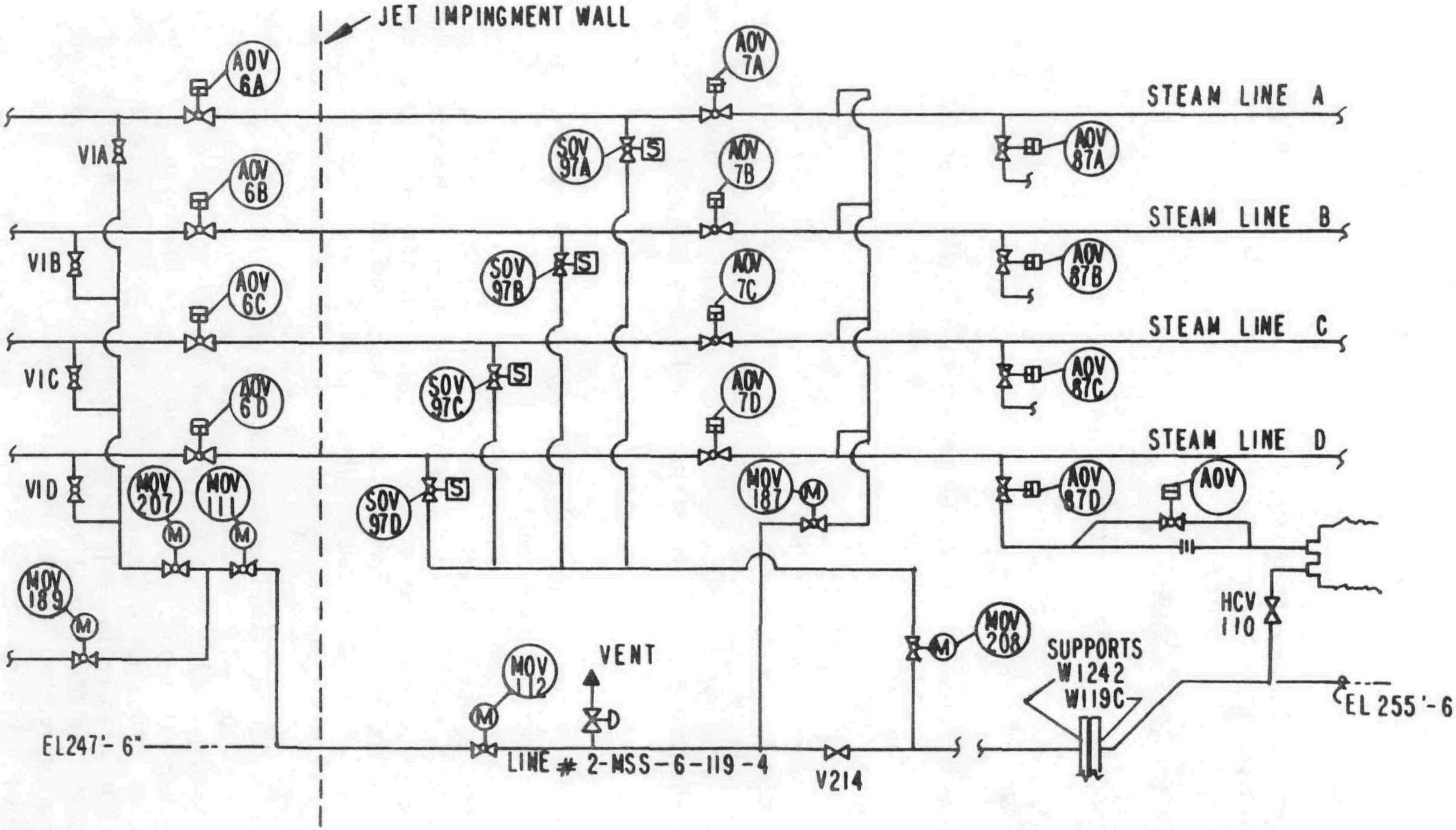


Figure 6.1 MAIN STEAM LINE AND DRAIN SYSTEMS

6.3 SEQUENCE OF EVENTS LEADING TO WATERHAMMER

Waterhammer in the drain header was detected during the plant's initial startup tests, in which the drain lines were used frequently. During these tests all lines in the plant are routinely walked down to check for waterhammer damage and other indications of hydraulic transients. Damage to four supports was discovered during a routine walkdown of the drain header.

6.4 DESCRIPTION OF DAMAGE

The locations of the damaged pipe supports is indicated on an isometric drawing of the drain header shown in Figure 6.2. (note the left/right directions in this drawing are reversed from Figure 6.1). Rod hangers which served as dead–weight supports were badly bent, base plates were torn from the wall, and restraint trunion pads were found to be shifted axially from their supports.

6.5 EVENT DIAGNOSIS

EVENT CENTER

The drain line is filled primarily with steam and small quantities of condensed liquid. Large piping loads due to steam flow alone are unlikely. Such loads are probably due to transients involving high velocity motion of the condensate, which suggests a saturated water slug event (see Section 2.1). A slug of liquid driven by high pressure steam through the drain header could have caused the support damage. The event center in this case is the entire length of the drain header through which the slug would have travelled.

FLUID STATE

Operating data from the initial startup tests is unavailable. The steam and condensate must have been saturated at the main steam system pressure. During startup tests MOV–111 was opened at steam pressures up to 950 psi, so assume initial saturation conditions at this pressure. The amount of condensate which might have accumulated in the drain header is difficult to estimate, and goes beyond the level of scoping analysis which can be performed during a diagnosis.

EVENT SCENARIO

Based on the above considerations, the following event scenario is proposed:

1. Void Formation

The void already exists at the start of a transient. It consists of the steam located between MOV–111 and the condenser.

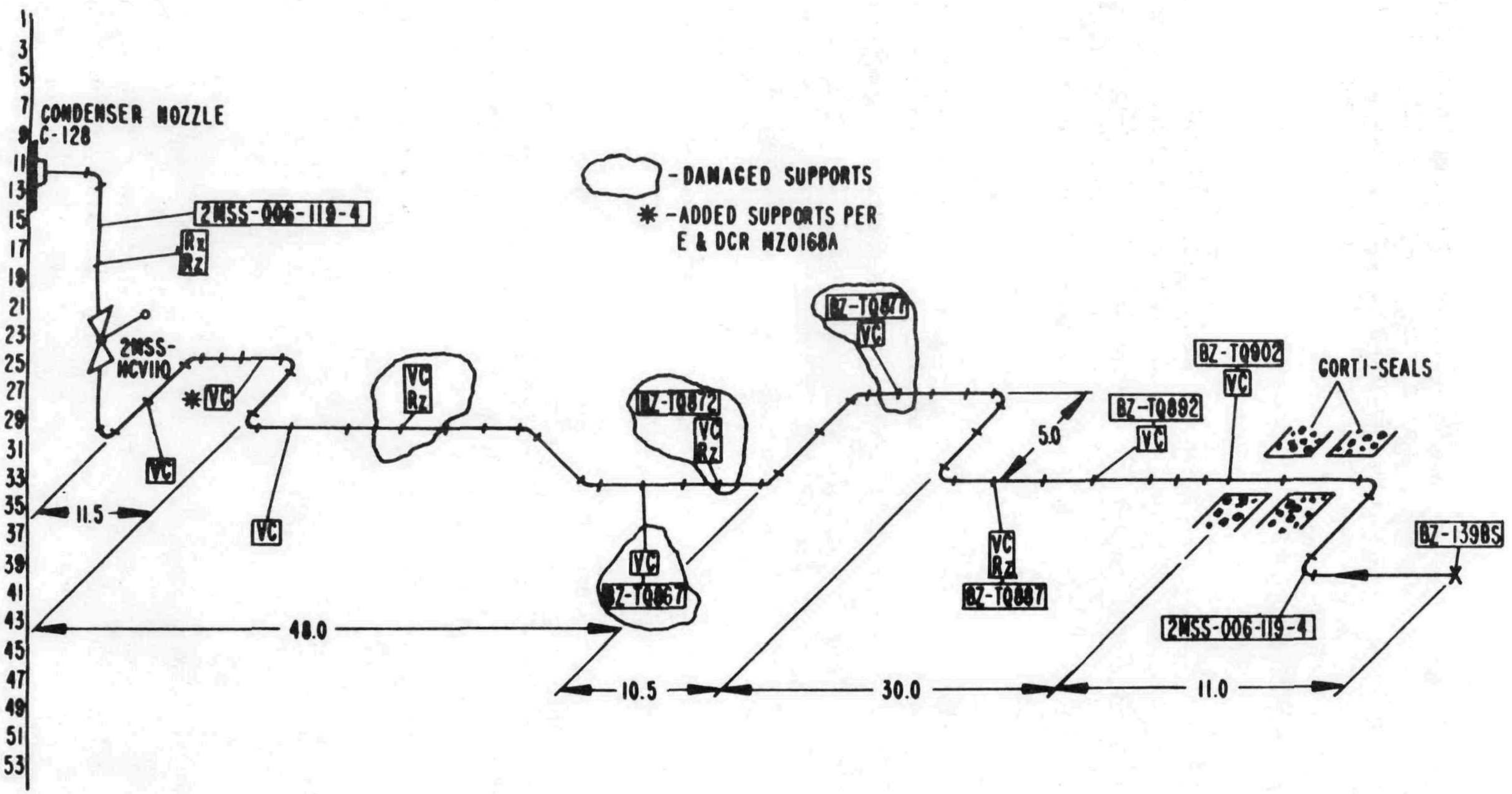


Figure 6.2 ISOMETRIC OF STEAM DRAIN HEADER LEADING TO THE CONDENSER

2. Slug Formation

A liquid slug could have formed in two ways. A slug of condensate might have accumulated upstream of MOV–111 due to steady drainage from the main steam lines. It is also possible that MOV–111 leaked by at high pressure and that a liquid slug accumulated at a low point in the drain header. Liquid could have leaked across MOV–187 and accumulated in the drain header. In any case, the slug existed prior to the event.

3. Slug Acceleration

The liquid slug is accelerated when the drain header isolation valves (111 and 112) are opened for condensate drainage at 950 psig following high pressure operation. There is a large force on the slug due to the difference in pressure between the steam lines and the condenser pressure, roughly 960 psia. This force accelerates the liquid slug through the drain header towards the condenser. The slug exerts reaction forces on any piping bends as it travels.

4. Void Collapse

As the liquid slug moves through the piping towards the condenser, the steam which lies downstream escapes to the condenser through the partially open HCV–110 valve. Since the steam flow through the 110 valve will probably choke at some point, the remaining steam downstream of the slug will be compressed and cushion the impact.

5. Impact

The liquid slug strikes the partially open valve and is suddenly decelerated. There is some overpressure at the 110 valve and a reaction force on the drain piping, though the forces due to deceleration are probably small.

SCOPING CALCULATIONS

There is very little information available to estimate piping forces based on the event scenario. The best that can be done is to estimate a range of forces which is likely to result from the assumed event scenario.

Referring to Section 5.2.5 in Volume 1, the force exerted on a 90° pipe bend by a passing slug is:

$$
\begin{aligned}
F &= (10.9)(960 \mathrm{lb_f/in^2})(6\mathrm{in})^3/L_s \\
&= 2{,}300{,}000 \text{ ft–lb}_f/L_s
\end{aligned}
$$

The distance from the first damaged pipe support to MOV–111 can be estimated from isometric drawings, and is found to be about 50 feet. The length of the slug is difficult to estimate. However, the above equation implies that for slugs of up to 50 feet in length, the segment forces would be greater than or equal to 45,000 $\mathrm{lb_f}$. The reaction forces generated when the slug passed by were probably substantial.

CONCLUSION OF INITIAL DIAGNOSIS

A saturated water slug event scenario is consistent with plant operating procedures. The range of piping forces calculated using this scenario is consistent with the level of support damage found after the event.

6.6 CONFIRMATION

This diagnosis was confirmed by successfully avoiding a repeat event. Immediately following the event, procedures were modified as a short term solution to the problem. Design modifications were adopted for a permanent solution.

The change in procedures is as follows (refer to Figure 6.1). Under normal shutdown conditions, the steam lines are not to be drained until the main steam system is depressurized and the reactor water temperature is less than 212 F. However, some situations require that the condenser heat sink be re–established under high pressure conditions through the drain header. The new procedures require that MOV–207 remain closed while MOV–111 and 112 are opened. Valve 207 is then to be "bumped" open gradually over a period of two minutes. This gradual opening prevents any liquid slugs which may exist in the pipe from being accelerated under full primary system pressure. These operating procedures prevented further waterhammers in the drain header.

For a permanent solution to this waterhammer problem, design modifications were proposed to prevent the formation of liquid slugs in the drain piping. The modified drain design is illustrated schematically in Figure 6.3. A 100 foot section of the drain line is resloped to form a new low point in the line to which a new 2 inch drain line was connected. The 2 inch line leads to the reactor building equipment drain cooler. Motor operated valves are installed to control the flow through the new drain line, and an additional MOV are installed in the original drain header upstream of HCV–110. The new valve in the header remains closed unless the header is to be drained into the condenser. A drain pot with a level switch signals that condensate is in the line, at which point operators activate the valves in the 2 inch drain line to remove this liquid. In this way the drain header is kept free of liquid slugs at all times.

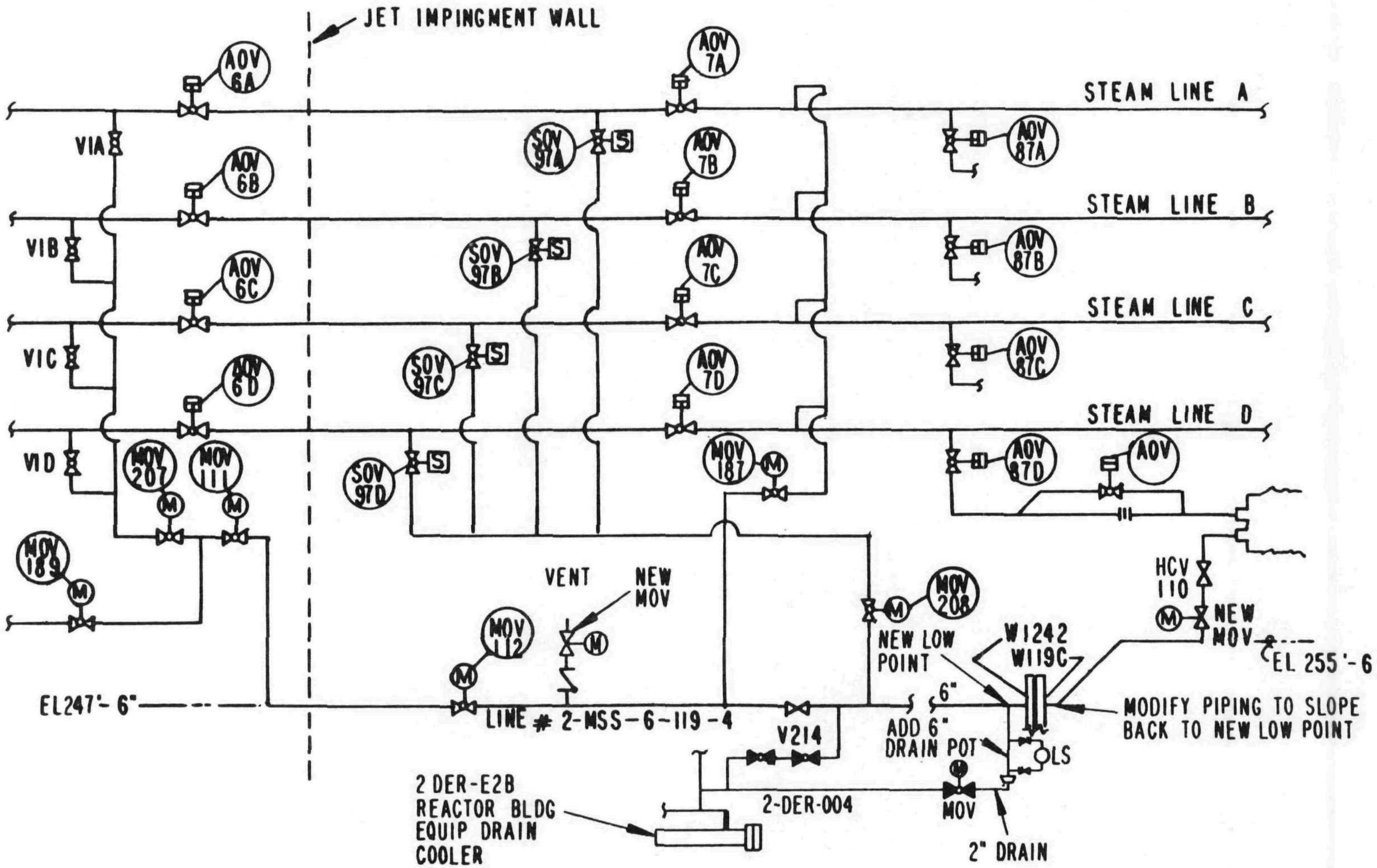


Figure 6.3 PROPOSED DESIGN MODIFICATIONS TO PREVENT WATERHAMMER

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This guidebook provides reference material and diagnostic procedures concerning condensation-induced waterhammer in nuclear power plants. Condensation-induced waterhammer is the most damaging form of waterhammer and its diagnosis is complicated by the complex nature of the underlying phenomena. In Volume 1, the guidebook groups condensation-induced waterhammers into five event classes which are have similar phenomena and levels of damage. Diagnostic guidelines focus on locating the event center where condensation and slug acceleration take place. Diagnosis is described in three stages: an initial assessment, detailed evaluation and final confirmation. Graphical scoping analyses are provided to evaluate whether an event from one of the event classes could have occurred at the event center. Examples are provided for each type of waterhammer. Special instructions are provided for walking down damaged piping and evaluating damage due to waterhammer. To illustrate the diagnostic methods and document past experience, six case studies have been compiled in Volume 2. These case studies, based on actual condensation-induced waterhammer events at nuclear plants, present detailed data and work through the event diagnosis using the tools introduced in the first volume.

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