EVALUATION OF
MAIN FEEDWATER PIPING MISALIGNMENT
AND STEAM GENERATOR NOZZLE CRACKING

BEAVER VALLEY POWER STATION UNIT 1

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EXECUTIVE SUMMARY

During the Beaver Valley Power Station-Unit 1 (BV-1) seventh refueling outage (7R), an ultrasonic examination of the first elbow outbound in the feedwater piping to steam generator RC-E-1A revealed an indication. Since this elbow had experienced fatigue cracking in the past a decision was made to replace the elbow. After replacement of the elbow, upstream piping alignment was reviewed and it was found that line 16"-WFPD-22-601-Q2 was bound against pipe rupture restraint FWR-38.

The purpose of this evaluation report is to identify and investigate the root cause of the feedwater system piping misalignment and steam generator nozzle cracking and to provide recommendations which will prevent the reoccurrence of these phenomena.

A brief description of the feedwater system, a summary of the 7R anomalies and action plan implemented prior to the unit's restart is provided.

Root cause considerations incorporating past industry experience included local and global thermal stratification effects, water hammer events, and installation practices. An instrumentation program was implemented to measure and quantify the mechanism that resulted in the damage. The instrumentation installed to record data included lanyard potentiometers, strain gages, thermocouples, accelerometers, linear velocity displacement transducers and pressure transducers. These data were thoroughly evaluated and correlated to analytical models.

During the root cause evaluation it was determined that a phenomenon occurs under certain plant conditions that was not included in the original plant design basis. Global thermal stratification, not considered in the design basis qualification of the feedwater piping system, was identified and quantified by data recorded during the plant restart following 7R. Furthermore, correlation of the recorded data to analytical results indicated that two monoball restraints are potentially locked up and are not functioning as required. Therefore the effects of global stratification and locked monoballs were considered in the reanalysis of the piping system. Based on the identification of the global stratification existence, combined with potentially locked monoball supports, a JCO has been prepared.

The results of the analysis show that the piping system stresses are within code allowables. Nozzle and penetration loadings meet design basis limits. All supports are satisfactory except for the two monoball supports under the assumption of bound monoballs. Alternate criteria were developed and demonstrated the acceptability of pipe supports and pipe break location selection until recommended activities can be completed during the next refueling outage.

The review of recorded data showed local stratification was occurring in the vicinity of the steam generator nozzle as anticipated. It also revealed that the number of thermal stratification events was greater than the number of events experienced by the plant. A plant event is defined as either a plant heatup or a reactor trip. It was shown that alternating stress levels were as high as 180 ksi and that crack initiation could begin after only sixteen plant events. Thus it was concluded that local stratification in the steam generator nozzle region is directly responsible for the cracking.

Studies to determine pipe misalignment included evaluation of design basis water hammer loads, time history loads generated from both feedwater regulating control valve instability, and steam generator water hammer (SGWH) loads. Design basis time history loads were determined not to be of sufficient magnitude to cause the observed misalignment. Although instability and SGWH can provide the required magnitude of loads (100-200 kips) and are addressed in this report, the piping misalignment was not accompanied by support damage. Therefore, it is concluded that the misalignment occurred during line positioning.

Corrective actions were determined and categorized as mandatory, strongly recommended and recommended. Mandatory corrective actions associated with the piping misalignment, steam generator nozzle cracking and unanalyzed conditions were identified. There are no mandatory corrective actions required for future possible water hammer concerns.

The mandatory corrective action for the irregular pipe deformation pattern is to realign the piping to its as-designed position. This was accomplished during the unit's 7th refueling outage.

The recommended corrective actions for the steam generator nozzle taper transition cracking are: (1) a modification to install thermal sleeves to prevent reoccurrence of the cracking, and (2) pre/post installation inspection of the feedwater line.

The mandatory corrective actions for the global stratification phenomenon are to:

1) Confirm analysis assumptions through an enhanced instrumentation program.

2) Revise pipe rupture criteria to be consistent with Mechanical Engineering Branch Technical Position 3-1 (MEB 3-1).

3) Measure the existing elbow wall thickness.

4) Modify the monoball supports R-3, R-4 and R-11 which do not meet plant design basis criteria.

5) Inspect supports to verify input assumptions.

6) Implement OBE seismic limits as determined during the interim evaluation.

7) Revise design basis documentation to include ASME Boiler and Pressure Vessel Code Case N-318.

Strongly recommended corrective actions, primarily considered with future possible water hammer events, and recommended corrective actions addressing other concerns, are also presented in this report.

ACKNOWLEDGMENTS

It is recognized that others contributed significantly in the generation of this report. Steve Collins developed the method of analysis and performed the qualification for effects due to global thermal stratification. Carol Allen performed the correlation study demonstrating the consistency between computer code methods to determine global stratification effects. Bob Kimball reduced and interpreted recorded data and evaluated the effects of local stratification. Yo Cho developed an instrumentation program to record, interpret and reduce feedwater system operating data.

INTRODUCTION

During the Beaver Valley Power Station-Unit 1 (BV-1) seventh refueling outage (7R), an ultrasonic examination of the first elbow outbound in the feedwater piping to steam generator RC-E-1A revealed an indication. Since this elbow had experienced fatigue cracking in the past a decision was made to replace the elbow. After replacement of the elbow, upstream piping alignment was reviewed and it was found that line 16"-WFPD-22-601-Q2 was bound against pipe rupture restraint FWR-38. Further review of rupture restraint FWR-38 revealed that shim pack clips were damaged and/or missing.
An extensive evaluation of the 'A' feedwater line and supports followed. Inspections were also initiated on the remaining feedwater lines 'B' and 'C'.

Damage similar to the 'A' line was found to exist on the 'C' line. Inspection of the 'B' line revealed no damage. A description of all observed anomalies and their respective dispositions are presented in Section 3.0 of this report.

Subsequently, it was determined that the feedwater lines for loops 'A' and 'C' had to be cut in order to reposition the lines properly within their respective rupture restraints. A review of the rupture restraints' orientation and installation precluded movement of the restraints to accommodate the piping.

It was decided to restore both the 'A' and 'C' feedwater lines to their original configuration and correct all anomalies prior to restart of the unit. In addition an extensive instrumentation program was implemented in order to gain an insight into the possible causes of the piping misalignments.

This report includes an in-depth review of the instrumented data taken, of records of past feedwater incidents both at BV-1 and in the industry , and of available literature associated with feedwater system problems in the area of nozzle fatigue cracking, local and global thermal stratification, and water hammer. Conclusions stated herein are derived both from this review and from analyses conducted specifically for this effort.

1.0 PURPOSE/SCOPE

The purpose of this evaluation report is to identify and investigate the root cause of the feedwater system piping misalignment and steam generator nozzle cracking discovered during the Beaver Valley Power Station-Unit 1 seventh refueling outage (7R) and provide recommendations to minimize the reoccurrence of these phenomena. The scope of this evaluation includes a brief description of the feedwater system, a summary of the 7R observed anomalies and a description of the action plan implemented prior to the units restart. During the investigation of the root cause(s) of the piping misalignment and nozzle cracking other potential feedwater system concerns which are not directly related to the root cause of the misalignment or cracking, may be identified. Recommendations will also be provided to correct any additional concerns beyond the piping misalignment and piping cracking.

2.0 DESCRIPTION/OPERATION OF FEEDWATER SYSTEM

The following description of the feedwater system pertains to the portion of the system from the main feedwater pumps to the steam generator. This is the primary area of interest for this report.

2.1 MAIN FEEDWATER SYSTEM

The main feedwater system is used to preheat and deliver condensate to three steam generators via a common feedwater header. Two steam generator supply pumps, each rated at 15,200 gpm at 1900 feet total dynamic head (TDH) supply the common header. Three individual steam generator feedwater lines are supplied by the feedwater header.

Each of these individual lines downstream of the feedwater header contains a flow measuring device, a main feedwater regulating valve controlled by a three-element steam generator water level control system, a bypass flow control valve controlled by a two-element level control system, flow control isolation valves and a motor operated containment isolation stop-check valve.

Techniques of providing feedwater flow to the steam generators are dependent upon plant condition. For example, when the plant is either in hot standby operation or escalating in power up through low power operation, feedwater flow is being directed through the bypass feedwater regulating valve. This feedwater flow could either be a continuous trickle flow (approximately 200 gpm), intermittent plug flow (as in a feed and bleed mode), or a combination of the two. Under these situations relatively cold water from the condenser hot well is introduced into the steam generator.

Once the main feedwater regulating valves are put in service, trickle flow or intermittent plug flow does not take place. The specific components of interest are discussed below in more detail.

2.1.1 MAIN FEEDWATER REGULATING VALVES

The valve is sized to control steam generator level from about 15% power to full power. Each valve is controlled automatically by a three-element steam generator level controller or manually from the control room bench board. The three-element control system continuously compares feedwater flow, steam flow and water level in order to maintain a programmed water level in the secondary side of the steam generator during normal operation.

The main feedwater regulating valves are Copes-Vulcan, 12 inch, 900 pound, cage and piston design with 16 inch inlets and outlets. The operators are also supplied by Copes-Vulcan with their failure mode being spring to close. A design change in 1982 installed hydraulic dampers on the actuators to provide better control over plug travel [Ref. 9.67].

2.1.2 BYPASS REGULATING VALVES

A bypass flow control valve is located in parallel with the main feedwater regulating valve. The bypass flow control valve is used for steam generator level control at power levels up to about 15% power. The bypass flow control valves are left partially open at high power levels to provide cooling water flow to the feedwater heaters during a reactor trip. The valve is controlled automatically by the two-element feedwater control system which senses steam generator level and reactor power level. A controller continuously compares the two signals to regulate the bypass control valve and hence control steam generator secondary side level. Manual local control of the valve can also be taken.

The bypass valves are Masoneilan 4 inch, 900 pound rated valves.

2.1.3 FEEDWATER ISOLATION

The main feedwater regulating valves trip on the following:

a. Two out of three (2/3) high-high (Hi-Hi) level signals in any steam generator.
b. Safety injection signal.
c. Low average temperature in 2/3 loops after a reactor trip.

The bypass flow control valves, the main turbine, the main feedwater pumps, and main feedwater containment isolation valves trip on the following:

a. (2/3) Hi-Hi level signals in any steam generator.
b. Safety injection signal.

2.2 AUXILIARY FEEDWATER SYSTEM

The auxiliary feedwater system is used to supply water to the steam generators in order to remove residual heat and cooldown the reactor coolant system when the main feedwater pumps are not available (i.e. feedwater isolation). The auxiliary feedwater pumps transfer water to the steam generators from the 152,000 gallon primary grade demineralized water storage tank (WT-TK-10).

Auxiliary feedwater is supplied to each steam generator through two redundant supply headers, each containing a motor operated throttle valve. The supply headers join downstream of the throttle valves and flow through a flow measuring device among other components prior to connecting into the main feedwater line. This connection is downstream of the main feedwater containment isolation valves but just up-stream of the containment penetration in the main steam valve house (MSVH).

The auxiliary pumps include two 350 gpm electric driven pumps which auto start in tandem and one 700 gpm steam driven pump as a backup to the electric pumps.

2.2.1 EVENTS TO INITIATE AUXILIARY FEEDWATER FLOW

The transients that cause an automatic start of the two electric auxiliary feedwater pumps are as follows:

a. Lo-Lo steam generator level signal in any two steam generators.

b. Both main feedwater pumps trip.

c. Safety injection signal.

For any of the above conditions to exist they would have to be proceeded by one of the following events:

a. Loss of normal feedwater.

b. Loss of offsite power followed by a reactor trip (results in a loss of normal feedwater).

c. Secondary side pipe rupture.

d. Cooldown following a steam generator tube rupture.

2.2.2 DESIGN CONSIDERATIONS FOR AUXILIARY FEEDWATER FLOW

When a transient condition as cited in Section 2.2.1 is presented, it takes on the order of one to two minutes before the auxiliary flow transmitters sense auxiliary feedwater flow. Presently, the initial auxiliary feedwater flow rate which can be experienced is on the order of 400 gpm per steam generator until control is taken through the auxiliary feedwater throttle valves.

The primary grade demineralized water storage tank which supplies the auxiliary feedwater system is housed in an enclosure which is maintained at or near ambient conditions. Freeze protection is provided in the form of two electric space heaters. Therefore the tank is not maintained much above freezing during subfreezing ambient temperatures.

2.3 FEEDWATER PIPING LAYOUT/SUPPORTS

The portion of the feedwater piping evaluated for misalignment and nozzle cracking is located inside the reactor containment structure from the containment penetration to the steam generator nozzle connection. Refer to Figures 2.3-1, 2 and 3 for the pipe support locations on loops A, B and C respectively. See Figure 2.3-4 for the pipe rupture restraint locations on all three loops.

The piping is A106 Grade B and fittings are 16 inch, A234 Grade WPB. For all three piping runs the pipe enters the containment at approximately elevation 758 and rises vertically about twenty feet. Then the pipes run horizontally outside the crane wall before penetrating the crane wall and running into the steam generators. Just prior to the steam generator nozzle connection in each loop is a loop seal comprised of four back to back short radius 90 degree elbows.

Monoball supports are the only supports on the feedwater lines that provide rigid constraint (vertical only) for all loading conditions. These supports are comprised of a ball and socket joint to allow free rotational displacements and self lubricating (Lubrite) plates to allow both free lateral and axial movement.

FEEDWATER LOOP A PIPE SUPPORT ARRANGEMENT

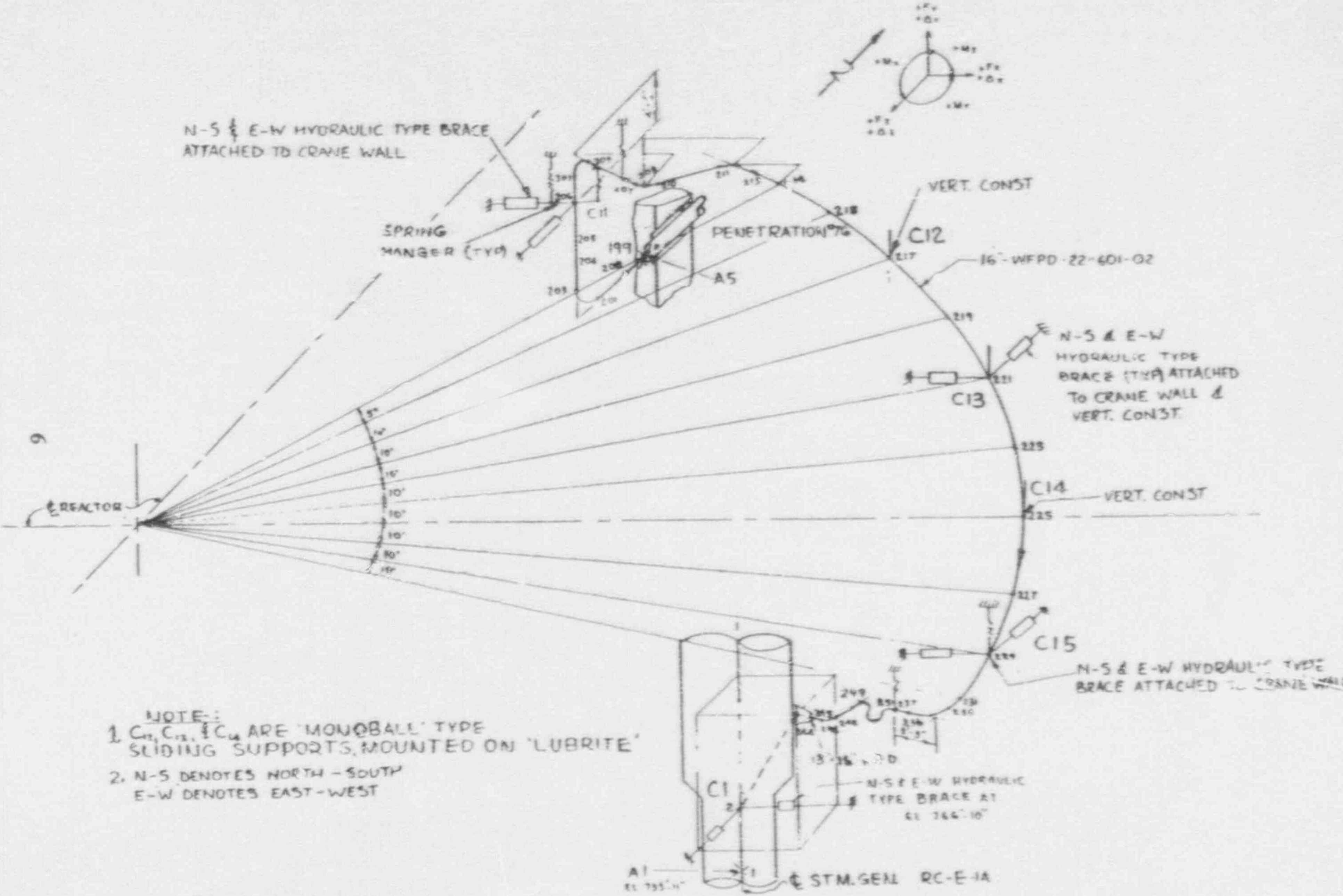


FIGURE 2.3-1

FEEDWATER LOOP B PIPE SUPPORT ARRANGEMENT

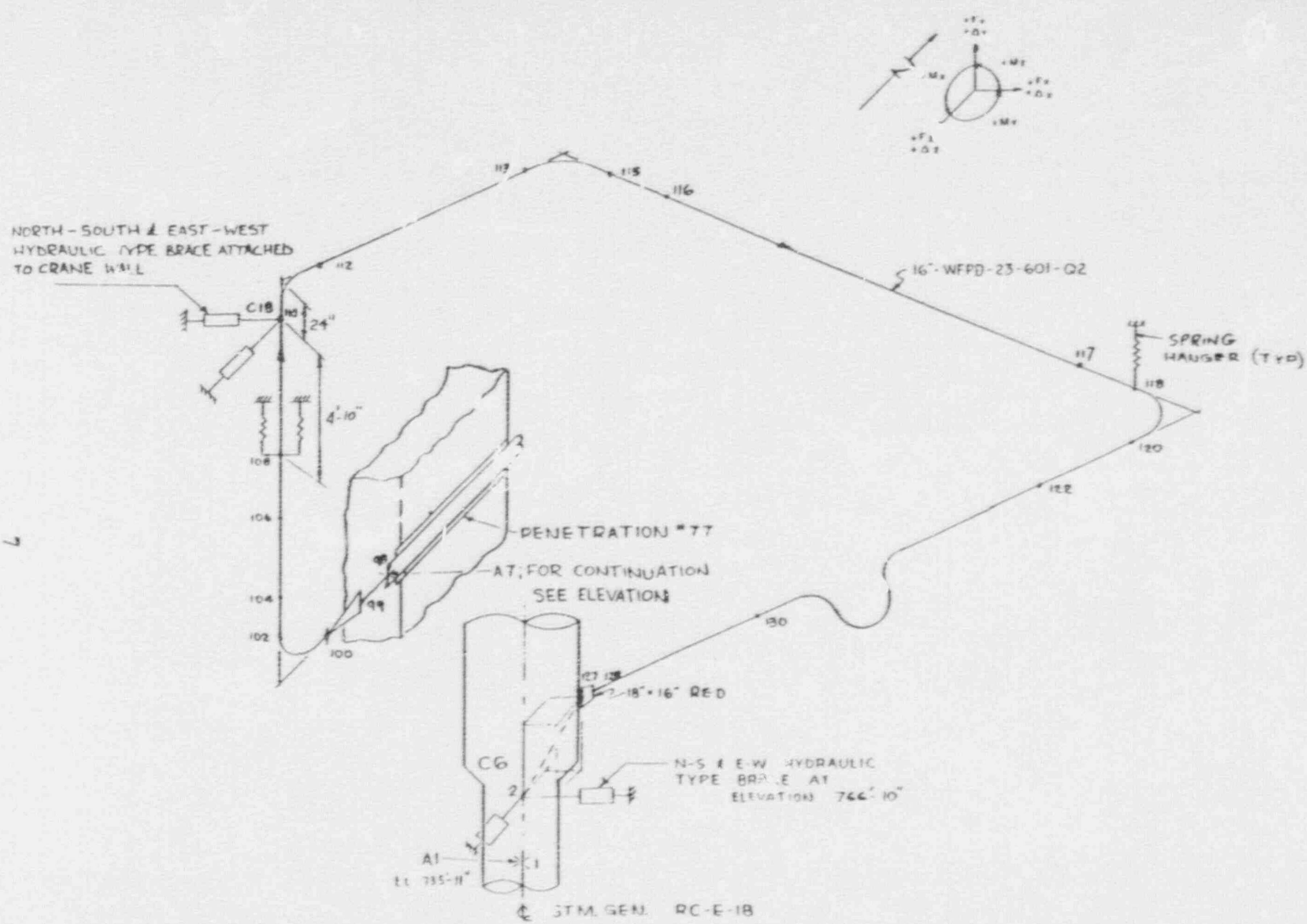


FIGURE 2.3-2

FEEDWATER LOOP C PIPE SUPPORT ARRANGEMENT

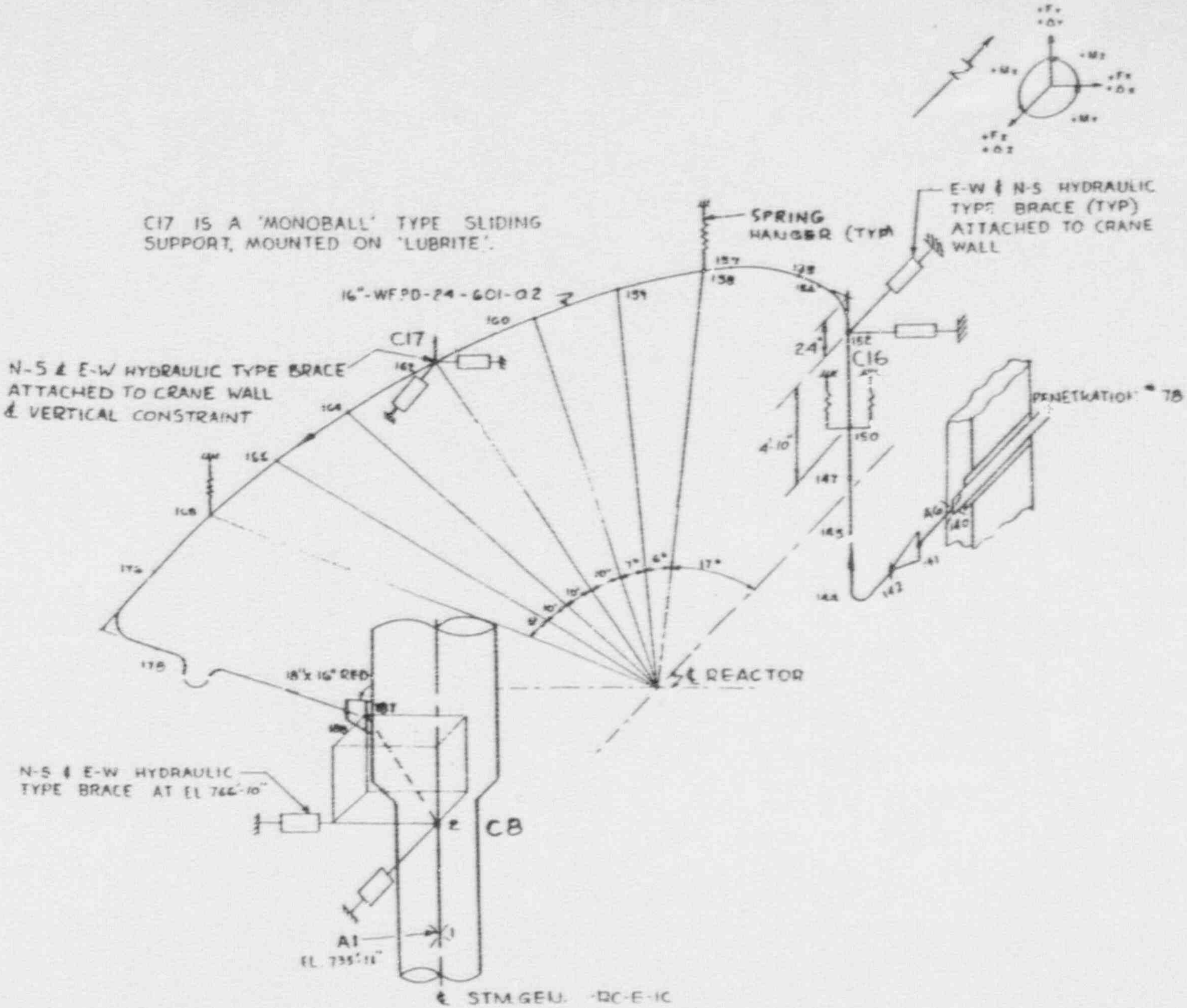


FIGURE 2.3-3

FEEDWATER LOOP A, B AND C PIPE RUPTURE RESTRAINT ARRANGEMENT

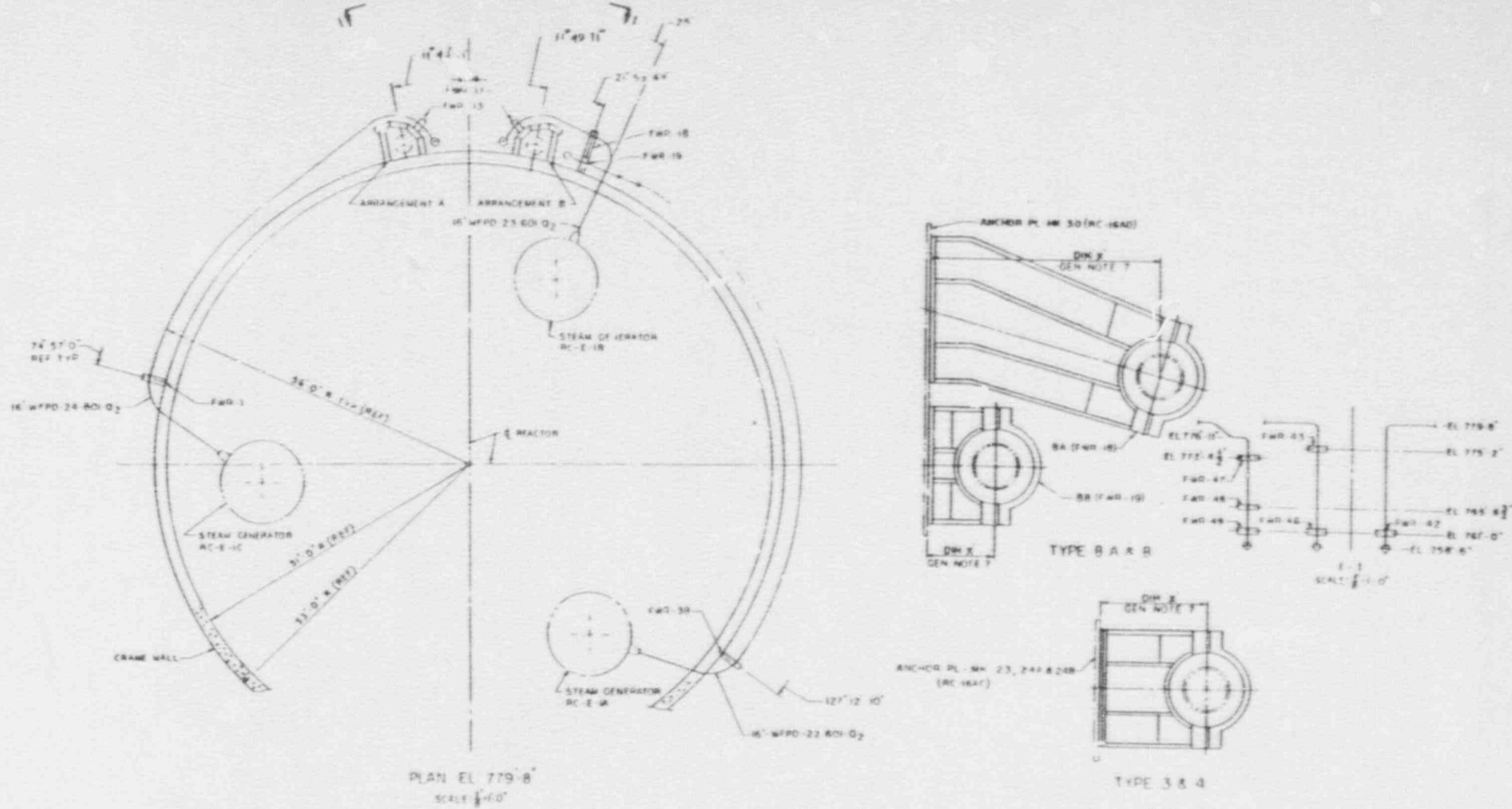


FIGURE 2.3-4

Rupture restraints are used to absorb energy and restrain pipe movement following a postulated pipe rupture. These restraints are nearly concentric to the pipe with shim stacks installed to provide the final gaps between the pipe and the restraint. These gaps allow sufficient clearance for free thermal and seismic movements. Unexpected closure of a pipe rupture gap will result in an unanalyzed condition and potentially increased stress levels and support loadings. Maximum allowable pipe gaps are calculated and design gaps are set equal to or less than this value to keep the energy imparted to the restraint within the design capacity of the restraint.

2.4 FEEDWATER FEEDRING DESIGN

The Westinghouse Model 51 steam generator utilizes a 12 inch distribution feedring inside the steam generator which lays horizontally at the same elevation as the incoming feedwater piping. The feedring to shell nozzle is connected via a thermal sleeve. This thermal sleeve is basically a slip fit into the back of the nozzle. Specified gaps for this slip fit are on the order of .025 inches.

The feedwater feedring employs J-tubes (2 inch schedule 80 A-106 Grade B) to discharge feedwater from the feedring. The purpose of the J-tubes is to prevent steam voids from developing in the feedring. The rapid collapse of a void in the feedring can result in a severe water hammer.

2.5 PRESENT DESIGN METHODOLOGY

The feedwater piping from the containment penetration to the steam generator is designed to Category I class Q2 requirements. The design incorporates normal thermal conditions and anticipated upset conditions such as seismic and time history events. These time history loads are associated with postulated water hammer events such as main feedwater regulating valve closure due to feedwater isolation, main feedwater containment isolation check valve slam and a main feedwater pump trip.

Feedwater temperature is a function of flow rate and reactor power level. The thermal analysis utilizes the design condition of 441° F at 100% power to envelop all intermediate feedwater temperatures.

The system, including the auxiliary feedwater nozzle and steam generator nozzle, is designed to withstand a thermal shock incident for incoming ambient auxiliary feedwater flow while the system is at normal operating temperatures and pressures.

In order to minimize steam generator water hammer events, a loop seal adjacent to the steam generator nozzle is employed to minimize the horizontal length of piping prior to the feedring to reduce the potential for bubble formation and the resulting water hammer. The loop seals also prevent steam, should it enter the feedring, from traveling back up the horizontal feedwater piping and causing more severe voiding. J-tubes are installed on the feedring to prevent steam from entering the feedring.

Current postulated break locations are at the terminal ends and at points along the vertical risers. The specific points are shown in Table 5.2-16 of UFSAR Section 5.2.6.3 and is reproduced here as Table 2.5-1. Refer to Figures 2.3-1, 2 and 3 for the location of the point numbers specified.

TABLE 2.5-1

FEEDWATER LINE POSTULATED RUPTURE POINTS

Location	Feedwater Lines 16-WFPD-22	16-WFPD-23	16-WFPD-24
Terminal Points	199 244	98 128	140 188
Point of Maximum Primary + Secondary Stress	307	102	144
Point Where $P + S > .8 (S_a + S_h)$	None	None	None
Point Where $P > .8$ Allowable $= .8(1.2) S_a$	203 [2] 202 [2] 307	102 [2] 101 [2] 110	144 [2] 143 [2]
Point Where $S > .8 S_a$	None	None	None
Total Points	5	5	4
Total Areas	4 [2]	4 [2]	3 [2]

Where: P = Primary Stress
S = Secondary Stress

S_h, S_a are defined in ASME III NC3611

Note: [1] With the exception of Pt 180 on 16-WFPD-24 all points listed above are at elbows.

[2] Because of the proximity of two points, the area between the two points is considered one break area.

3.0 DESCRIPTION OF 7R OBSERVED ANOMALIES

The following conditions were observed on the containment feedwater piping during the seventh refueling outage (7R). An extensive inspection/evaluation of all three feedwater lines was conducted once anomalies on the 'A' line became apparent.

3.1 'A' FEEDWATER LINE

The specific anomalies found included:

a. Pipe break restraint, FWR-38, had the pipe blocked up against the restraint, shims dislodged on two shim packs and shim retaining clips bent.

b. Pipe break restraint, FWR-19, had the top wear plate shifted at one shim pack only.

c. Hydraulic snubber, HSS-201, had surface cracking along the edges of the embedded plate.

d. Vertical monoball support, R-5, had loose bolts on the support frame, concrete spalling at crane wall,and evidence that free lateral and axial translation was not taking place as designed.

e. Spring can, SH-1, was topped out and not supporting any load.

f. Hydraulic snubber, HSS-206, had a loose nut on the pipe clamp.

g. Monoball supports, R-3 and R-4 had the pipe bound up against the crane wall.

h. No other pipe support or pipe discrepancies other than those listed in a through g were observed.

The effect of the above observed anomalies on the qualification of the feedwater line included:

a. Additional thermal stresses generated by restraining the line with the rupture restraint and monoball supports in the undesigned restrained direction.

b. Effect on the dynamic analyses by changing the modal response due to support function changes (i.e. rupture restraint gap closure and monoball lateral/axial direction restraint.

c. Reduced flexibility (increase in earthquake anchor loads).

See Figure 3.1-1 for a summary of as-found 7R piping conditions.

3.2 'B' FEEDWATER LINE

Extensive inspections were also conducted on the 'B' feedwater line and only one minor anomaly was observed.

a. FWR-14 had one slide plate move approximately 0.6 inches.

3.3 'C' FEEDWATER LINE

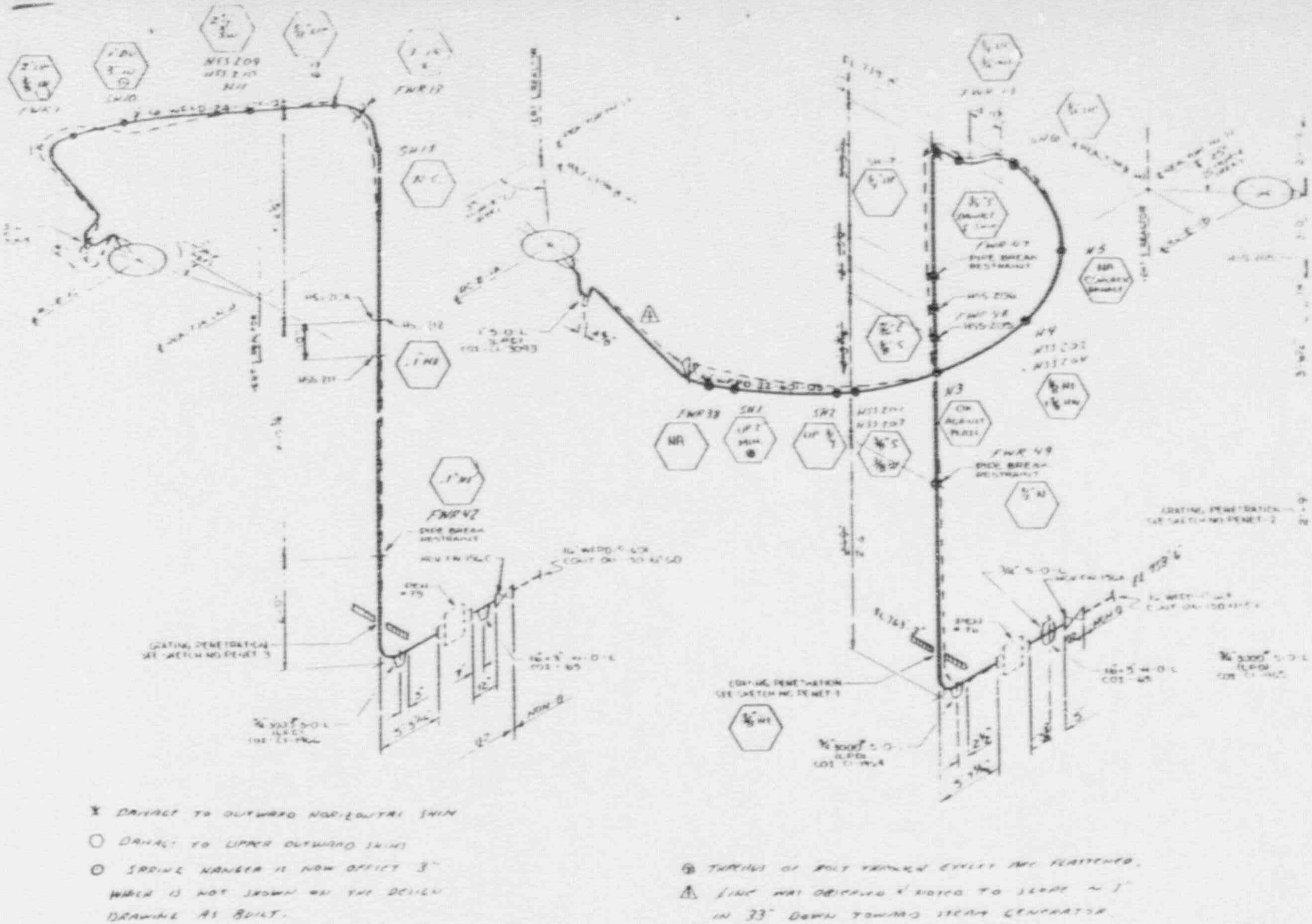
a. Pipe break restraint, FWR-1, had the pipe blocked up against the restraint, outboard shim brackets bent, and shims missing and dislodged. Four of 8 shim stack locations were affected.

b. Vertical monoball support, R11, had loose bolting on the angle iron.

c. Pipe break restraint, FWR-13, had a wear plate loose, shims shifted down, and the pipe hard against the inside of the restraint.

Contact of the line with the rupture restraint had the effect of elevating thermal stresses in the line since it was not free to move in the vertical direction as designed. This also would have an impact on the dynamic analyses since individual mode shapes would be affected.

In addition an outboard shim pack was dislodged thereby increasing the rupture restraint gap in that direction beyond design. During a design basis terminal end break at the steam generator, energy input to the rupture restraint may have exceeded the restraint's energy absorption capacity. This problem no longer exists because the pipe was relocated to its as-designed location during 7R.



7R AS-FOUND PIPING CONDITIONS

FIGURE 3.1-1

4.0 ACTION PLAN (STEPS TAKEN PRIOR TO RESTART FROM 7R)

4.1 INTRODUCTION

This section of the report delineates the course of action taken during the seventh refueling outage (7R) to document any anomalies that existed, and to evaluate these anomalies analytically to ensure that no other piping or support damage may have resulted (e.g., thermal overstress). All the supports including all rupture restraints, spring hangers and snubbers, were inspected. If a reference is not made to a specific support under Section 4.2 then no discrepancies were found. Any other areas of concern that required inspections are also noted in Section 4.2.

In addition once this review was conducted some additional inspections resulted. All of the observed pipe and support discrepancies were corrected prior to startup, except the pipe up against the crane wall at R-3 and R-4. The feedwater lines were restored to their original design position.

The instrumentation program was implemented to determine the mechanism that led to the pipe misalignment. The instrumentation was used to continuously record during the complete heatup of the unit from cold shutdown. This instrumentation will be used periodically during the course of the next fuel cycle as warranted.

4.2 COMPILATION OF 7R INSPECTIONS

4.2.1 'A' FEEDWATER LINE

a. Spring can, SH-1, was topped out and not supporting any load.

b. Vertical monoball support, R-5, had loose bolts on the support frame, concrete spalling at crane wall,and evidence that free lateral and axial translation was not taking place as designed.

c. Hydraulic snubber, HSS-201, had surface cracking along the edges of the embedment plate.

d. Hydraulic snubber, HSS-206, had a loose nut on the pipe clamp.

e. Pipe break restraint, FWR-38, had the pipe blocked up against the restraint, shims were dislodged on two shim packs and shim retaining clips bent.

f. Pipe break restraint, FWR-19, had the top wear plate shifted at one shim pack only.

g. Ultrasonic Testing (UT) examination of the complete 5D pipe bend in the vicinity of FWR-38 showed no indications. An ovality check demonstrated ovality was acceptable.

h. Surface examination of pipe wall at monoball restraint R5 showed no indications.

i. Radiograph and UT examination of the elbow to steam generator nozzle weld after fitting replacement showed acceptability.

4.2.2 'B' FEEDWATER LINE

a. Pipe break restraint, FWR-14, had one wear plate slide approximately 0.6 inches.

4.2.3 'C' FEEDWATER LINE

a. Pipe break restraint, FWR-1, had the pipe blocked up against the restraint, outboard shim brackets bent, and shims missing and dislodged. Four of 8 shim stack locations were affected.

b. Vertical monoball support, R11, had loose bolting on the angle iron.

c. Pipe break restraint, FWR-13, had a wear plate loose, shims shifted down, and the pipe hard against the inside of the restraint.

d. UT examination conducted on the complete 5D pipe bend in area of FWR-1 showed no indications. An ovality check demonstrated the ovality to be acceptable.

e. UT examination of the steam generator nozzle to elbow weld and counterbore area was performed and no indications were found.

4.3 EVALUATION/ANALYSIS OF AS-FOUND CONDITION

Prior to instrumenting the feedwater lines, analyses were conducted on both the 'A' and 'C' feedwater lines in an attempt to understand the cause of the anomalies and to determine if any other detrimental effects might have been imparted to the piping system.

Various sample thermal analyses were run to qualify the observed deficiencies. For example, the 'A' line translational displacements were restrained, individually and concurrently, at pipe support and pipe rupture restraints suspected of restricting pipe movement to derive the worst scenario.

Under these thermal cases the worst case derived was restraining the vertical and lateral directions of the pipe at FWR-38 and concurrently restraining all translation displacements at monoball R5. This case yielded an overstress at the first elbow off of the steam generator nozzle. The stress level shown was on the order of 27 ksi which was only slightly over the 25 ksi allowable [Ref. 9.11].

In addition, a local pipe wall overstress was shown to have occurred at monoball R5. Due to these results additional inservice inspection (ISI) on those analytical code overstress regions was conducted as defined above.

The pipe against the crane wall at monoballs R3 and R4 was judged to have an insignificant effect for the worst thermal case because the thermal deflection moves the pipe away from the crane wall.

On the 'C' line, analyses were conducted by restraining the line at FWR-1 since this is the only location where the line was observed to be constrained. A slight code overstress was shown at the steam generator nozzle to elbow transition region [Ref. 9.11]. Additional ISI as detailed above was then conducted.

For the seismic scenario, the pipe was restrained as in the thermal case run but included disabling snubber HSS-201 on the 'A' line because of the observed surface cracking at its embedded plate. For both the 'A' and 'C' lines the dynamic analyses demonstrated acceptability to code requirements.

4.4 REPAIR/MODIFICATIONS

The following is a compilation of all the repairs conducted during the seventh refueling outage prior to startup in order to return both 'A' and 'C' line stress levels to within code acceptability.

a. Replaced first elbow off the steam generator nozzle in loop A due to observed indication under UT examination. Further destructive evaluation revealed that this may have been a machining mark or possibly the onset of crack initiation.

b. Restored rupture restraints FWR-38 and FWR-1 to within design limits by providing adequate gaps to allow free normal thermal movement and dynamic clearances. Gaps were also set to account for energy input into the restraint. Min-K insulation was utilized at restraint locations to facilitate inspection of gap settings in the future.

c. Reset spring hangers SH-1 and SH-10.

d. Restored function of snubber HSS-201 by utilizing alternate embedded plate to maintain the same direction of constraint by the snubber.

e. Replaced monoball R5 with a new support design to retain same support function.

f. Verified acceptability of gap settings on all rupture restraints.

g. Both 'A' and 'C' feedwater lines had to be cut and mitered to allow correct repositioning through the rupture restraints.

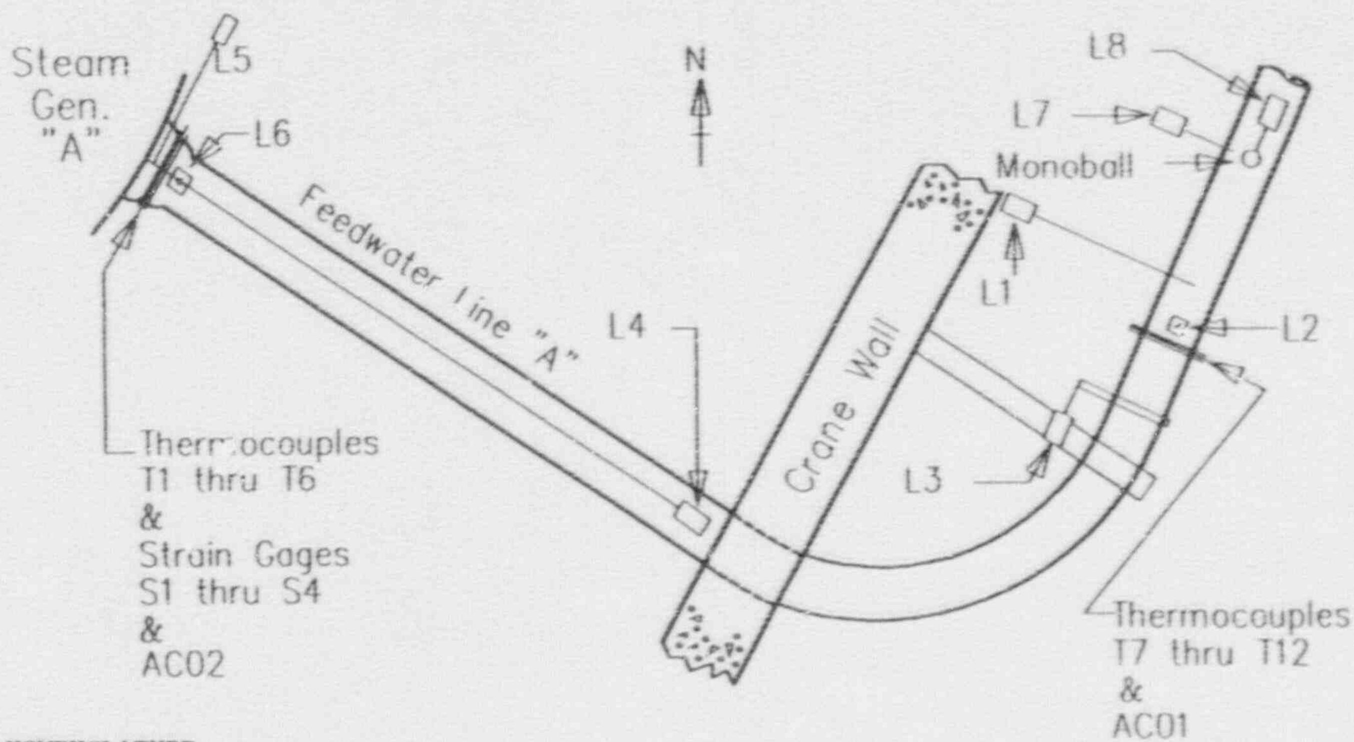
4.5 IMPLEMENTATION OF INSTRUMENTATION PROGRAM

An instrumentation program on the 'A' feedwater line was implemented prior to startup of the unit to aid in determining root cause of the piping misalignments and the steam generator nozzle to elbow counterbore cracking.

The instrumentation layout is depicted in Figure 4.5-1 and summarized below:

a. Full bridge strain gages to capture horizontal and vertical plane bending and torsion at the elbow counterbore location were installed.

LOOP A POST 7R INSTRUMENTATION PLAN



NOMENCLATURE

T = THERMOCUPLE
S = STRAIN GAGE
A = ACCELEROMETER
L = LANYARD

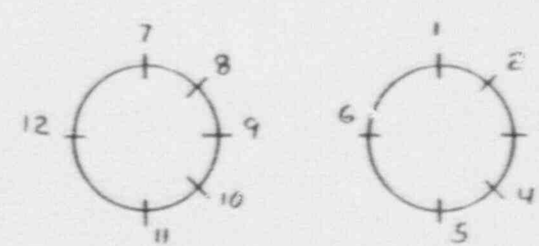


FIGURE 4.5-1

b. Lanyards to measure both static and dynamic displacements were installed at the following locations:

   1. Three directional displacements at the steam generator nozzle location (lanyards 4-6).

   2. Three directional displacements at the pipe in the vicinity of rupture restraint FWR-38 (lanyards 1-3).

   3. Lateral and axial lanyards at vertical constraint R5 (lanyards 7-8).

c. Accelerometers, one at each location where the three directional lanyards were applied. This provides local acceleration levels and modal information.

d. Six thermocouples were installed circumferentially on the elbow counterbore region to measure local thermal cycling effects. Six thermocouples were also installed circumferentially on the piping several diameters upstream of the loop seals to determine if the elbow loop seals were effective in preventing back leakage from the feedring and to determine if global thermal stratification existed.

   These thermocouples were not sufficient to completely describe global stratification profiles, but were only used to determine if global stratification existed. Based upon prevailing industry beliefs, global stratification was not initially thought to exist in this pipe due to both the location of the auxiliary feedwater connection and the vertical runs of feedwater piping where mixing would have been expected to occur.

e. A pressure transducer was installed downstream of main feedwater regulating valves, FCV-FW-478, 488 and 498. This was used to determine if the main feedwater regulating valve was inducing pressure oscillations in the system (i.e., control valve instability).

f. A linear velocity displacement transducer (LVDT) was placed on the stem of FCV-FW-478 to determine if stem oscillations were occurring.

Oscillations could occur as a result of valve resonance with the piping system at a specific flow rate. Specific flow rates can be correlated to precise plant power level.

Monitoring of the above parameters was performed continuously during the complete heatup of the unit following the refueling outage. This allowed data to be extracted during all modes of interest including hot standby operation, low power ranges and power escalation.

Plant recorded data (e.g., feedwater flow rate, auxiliary feedwater flow rate, steam generator level, feedwater pressure, reactor coolant loop temperature, etc.) gathered by permanently installed devices were collected along with the data from the temporary instrumentation. This was performed to provide the basis for data correlation to specific plant operation.

The temporary instrumentation has remained in place after 100% power was achieved but is presently not recording continuously. Additional data will be recorded under plant transient conditions since these are the time periods where more data are needed. A software program has been written to allow automatic recording of data under a transient condition. Specifically when thermocouple T-11 (refer to Figure 4.5-1) experiences a temperature drop of 10° F over less than 120 seconds recording begins. Thermocouple T-11 is on the bottom of the pipe. The instrumentation program has been documented in Reference 9.41.

Manual cooldown (transient condition) data were collected for the two cooldowns that have been experienced by the plant since the temporary instrumentation was installed. These events occurred on January 19, 1990 and October 6, 1990.

4.6 STATUS/DISCUSSION

Both feedwater lines 'A' and 'C' were returned to their original design basis through the work conducted in 7R. This included complete correction of all observed deficiencies considered to be significant. Consideration of the instrumentation recorded data was required to aid in root cause evaluation of both the elbow counterbore cracking and the irregular deformation pattern of the piping.

With current design basis considerations being evaluated (i.e., time history loads for current postulated water hammer events), it was concluded that the current analyzed postulated events couldn't generate loads of sufficient magnitude to move or deform the pipe into its 7R as-found condition.

It became evident that a review of existing industry literature of feedwater perturbations was necessary to determine sources of possible significant loads outside of current design basis considerations. The significant events reviewed were steam generator water hammer (SGWH) and feedwater control valve instability. Global stratification at this point was not documented or its effects quantified on Pressurized Water Reactor feedwater piping as evident through NRCs AEOD study published in March 1990 [Ref. 9.21].

When instrumentation mounted in 7R demonstrated that global stratification was present, steps were taken to incorporate its effects into the design calculations. Subsequent review determined that global stratification, although present, wasn't the source or root cause of the observed 7R misalignment. Water hammer events and past installation practices of the feedwater elbows became suspect.

The remainder of this report addresses these factors for root cause effects, investigates the potential for these events to occur in the future at BV-1 and identifies steps that can be taken to minimize their reoccurrence.

5.0 ROOT CAUSE CONSIDERATIONS (INCORPORATING PAST INDUSTRY EXPERIENCE)

Historically feedwater lines at both Pressurized Water Reactors (PWRs) and Boiling Water Reactors (BWRs) have been associated with several concerns. Some of these concerns include internal surface cracking (local thermal stratification), global thermal stratification, and severe water hammer. Several organizations have studied many of these problems in great detail. Many of these studies were obtained and reviewed. Their results and conclusions were incorporated into this evaluation to aid in identifying the root cause(s) of the taper transition cracking and the irregular deformation pattern of the feedwater piping.

5.1 LOCAL STRATIFICATION

Local stratification has been identified as a source of pipe line cracking in feedwater lines at both BWRs and PWRs [Refs. 9.16, 9.17 and 9.18]. The local stratification phenomenon occurs in the vicinity of the nozzle to the reactor in a BWR and in the vicinity of the nozzle to the steam generator in a PWR. This phenomenon occurs during plant heatup when low temperature feedwater is mixed with high temperature fluid from the reactor in a BWR or steam generator in a PWR. Since this investigation reviews taper transition nozzle cracking at the Beaver Valley Power Station-Unit 1 loop A steam generator, a detailed review of NRC IE Bulletin 79-13 "Cracking in Feedwater System Piping" [Ref. 9.12] was performed and the results of the review follow.

5.1.1 NRC IE BULLETIN 79-13

On June 25, 1979, the NRC issued IE Bulletin No. 79-13 to address cracking in PWR feedwater system piping. Cracking was first identified in May 1979 at DC Cook Unit No. 2. Leaking circumferential cracks were identified in the 16 inch feedwater elbows adjacent to two steam generator nozzle elbow welds. In order to further explore the nature and magnitude of the cracking problem industry-wide, the office of Inspection and Enforcement requested licensees of PWR plants to conduct volumetric examination of certain feedwater piping welds. Beaver Valley Power Station-Unit 1 was one of several units that identified cracking in the feedwater piping to vessel nozzle weld region.

A Westinghouse Owners Group (WOG) was formed. Westinghouse, acting as the agent for the WOG, investigated the feedwater line cracking phenomenon. Their results were published in several ASME papers [Refs. 9.16, 9.17 and 9.18]. The investigation concluded that the cracking occurred as a result of corrosion assisted fatigue. Westinghouse recommended the installation of thermal sleeves to reduce the heat transfer rate in order to protect the feedwater line taper transition nozzle weld to the steam generator.

5.2 GLOBAL STRATIFICATION

General stratification of water in piping was first reported by the NRC in Information Notice 84-87 [Ref. 9.59], which cited a major event in feedwater piping at WNP-2 that resulted in damage to supports and some leakage at the flanged connection. This type of stratification is due to the slow flow of cold water into a region of hot water, or vice versa, which causes the pipe to bend, leading to excessive deflection in long horizontal runs of pipe. The event at WNP-2 resulted from the slow admission of cold feedwater (about 100° F) into a horizontal run of pipe previously heated to about 400° F. The difference in temperature between the top and bottom of the pipe due to stratified flow caused the pipe to deflect and damage several feedwater pipe hangers and snubbers, and also loosen a flange allowing a small leak.

Global stratification has been a subject of increased visibility since the issue of NRC Bulletin 88-11 [Ref. 9.42]. This bulletin describes global thermal stratification in the pressurizer surge line. Global thermal stratification is defined as a top to bottom pipe temperature differential which can occur over a portion or entire horizontal length of piping under consideration. The potential exists for global thermal stratification any time a low flow injection of fluid occurs in a line sized for much larger flow and a temperature differential exists between the injected flow and the fluid already in the line. This potential exists on the feedwater line after a reactor trip when the feedwater line at a maximum possible temperature of 441° F experiences low flow injection of auxiliary feedwater at a temperature which can be as low as 45° F. Data collection at Beaver Valley Power Station-Unit 1 also indicates that significant stratification can occur when feedwater flow is stopped. This is due to the tendency for the more buoyant hot water to rise and cold water to fall (natural convection).

The top to bottom temperature differential causes the piping to deflect in an unexpected direction and with a larger magnitude than plant design basis calculations predict. This was also true with the pressurizer surge line as described in NRC Bulletin 88-11. The AEOD study summarized in the following section is another industry investigation of global thermal stratification.

5.2.1 NRC AEOD STUDY

The study, entitled 'Review of Thermal Stratification Operating Experience', issued in March 1990 by the Office for Analysis and Evaluation of Operational Data (AEOD) [Ref. 9.21], delineates all reported thermal stratification events to-date (including both local and global stratification). The report was reviewed to determine if feedwater global thermal stratification has been reported at other plants.

Other than the pressurizer surge line [Ref. 9.42], the only specific recorded instance of global stratification that resulted in support damage was at Washington Nuclear Plant Unit 2 (WNP-2) on the feedwater system in 1984. WNP-2 is a BWR. This event occurred when plant personnel slowly admitted cold feedwater into a pipe filled with high temperature water. It also occurred when reactor water clean-up (RWCU) (hot water) was admitted to cold piping which caused back flow and stratification.

Global stratification has not been associated with PWR feedwater piping to-date in the industry. However global stratification was still reviewed as a potential source of the piping misalignment since injection of colder fluid into the feedwater system takes place under auxiliary feedwater injection. The identification of this as a mechanism to cause global thermal stratification in PWR feedwater piping could become a new industry issue that would have to be addressed.

5.3 WATER HAMMER

Water hammer in PWR feedwater systems has been identified as the phenomenon which has plastically deformed piping and broken pipe supports. Several detailed investigations have been performed [Refs. 9.24 through 9.38]. These studies investigated the different aspects of flow control valve instability and steam generator water hammer due to bubble collapse. A detailed review of these phenomena follows the present Beaver Valley

Power Station-Unit 1 water hammer design considerations discussion which includes rapid check valve closure (VCW-90 AV) due to pump trip, flow control valve closure (FCV-FW-478, 488 and 498) and isolation valve (MOV-FW-154A, B, and C) closure. Design modifications were instituted which eliminated the need to evaluate flow control valve instability and bubble collapse.

5.3.1 PRESENT BEAVER VALLEY POWER STATION-UNIT 1 DESIGN CONSIDERATIONS

Beaver Valley Power Station-Unit 1 feedwater lines have been analyzed to withstand the effects of the following water hammer events [Ref. 9.43].

a. Feedwater pump P-1A or P-1B tripping resulting in a closure of check valve VCW-90AV downstream of the pumps at 100% and 75% power levels.

b. The closure of flow control valves FCV-FW-478, 488 and 498 at 100% power level.

c. The closure of isolation valves MOV-FW-154A, B and C.

No other significant water hammer events were identified and specified in the licensing documents. The analysis of the above water hammer transients provides the following significant conclusions:

a. The 100% power condition provides higher peak loads than the 75% power condition when both pumps are tripped.

b. Peak loads are higher on the piping inside containment when both pumps are tripped.

c. The pump trip loads are significantly greater than those from the flow control valve closure and are generally bounding for all three water hammer events considered above.

d. The analysis of feedwater piping inside containment [Refs. 9.7, 9.8 and 9.9] for design basis water hammer transient events results in stresses well within ANSI B31.1 1967 code allowable limits.

e. The feedwater pipe supports inside containment are designed to withstand the water hammer loads.

f. The maximum water hammer unbalanced force was determined to be less than 15 kips.

5.3.2 FLOW CONTROL VALVE INSTABILITY

Flow control valve instability has been identified in initiating water hammer events. This mechanism was reviewed to determine if it could have led to the observed piping misalignment. As reported in NUREG 0582 [Ref. 9.24], by 1979 twenty-two water hammer events had been attributed to main flow control valve opening, closing or instability.

The term "flow control valve instability" has been used generically to encompass several contributing factors, all of which could lead to a water hammer event. These factors include unbalanced hydraulic forces on the valve plug which may cause the valve to override the force applied by the actuator or, improper valve flow characteristics (ratio of flow to plug travel) or improperly adjusted control circuitry which may cause a rapid change in valve opening or closing. Another factor which could lead to a water hammer event is possible resonances set up by the dynamic characteristics of the valve and valve actuator. Resonance is the amplifying effect caused when an input or forcing function frequency and the natural frequency of a system/sub-system coincide. Two sources associated with flow control valve resonance are identified below:

a. Standing wave frequencies, defined as pressure oscillations in the piping system, are a function of both the speed of sound in the medium at the specified temperature and length of the piping.

b. Valve plug/stem frequencies, defined as oscillations of valve plug movements, are a function of both mass and stiffness of the valve plug and valve body.

Resonance established by a and b above, requires that the valve be dynamically coupled to the fluid system. This dynamic coupling effect would result in valve oscillations feeding or driving the fluid system standing waves and producing pressure oscillations. The result of the pressure oscillations in turn would have the effect of trying to move the valve plug in and out of the valve body. Instability results as valve stem oscillations amplify.

This resonance phenomenon "called impedance coupled valve/piping instability", could result in severe chattering or vibrations locally at the valve, and can induce large sinusoidal pressure oscillations resulting in significant forces being introduced into the piping system. Local valve vibrations could be responsible for fatigue failure of items such as the valve stem, yoke studs, feedback linkage, etc.

Sinusoidal resonance oscillations, if produced, would have the same frequency as the valve oscillations with pressure variations as high as 600 psi [Ref. 9.35]. This amount of pressure variation could be responsible for loads on the order of 100 kips [Ref. 9.35]. Loads on this order of magnitude would cause significant pipe support and piping damage. However , hydraulic dampers, which have been implemented at several plants including Beaver Valley Power Station-Unit 1, severely limit large valve oscillations and hence large pressure variations.

Instrumentation data recorded during 7R at all power levels confirmed that large valve plug oscillations are not occurring and that pressure oscillations are not being induced into the system.

5.3.2.1 PAST BEAVER VALLEY POWER STATION-UNIT 1 WATER HAMMER EVENTS

There have been four documented water hammer events at Beaver Valley Power Station-Unit 1 since the plant became operational in 1976. The specific details of each event have been previously reported to the NRC under Licensee Event Reports (LERs) which have been accompanied by formal evaluation reports. These are included under the list of references and provide additional detail.

The root cause of the three water hammer events occurring in late 1976 and early 1977 have been associated with plug/trim instability (consistent with improper valve characteristics). These events were associated mainly with the 'B' feedwater line. A replacement of the original plug-type trim with a cylindrical trim was implemented after the January 5, 1977 event. This change was implemented to reduce cavitation and unbalanced forces in the valve which had been associated with the unstable operation of the valve.

The only other documented water hammer event occurred in 1981 on the 'A' feedwater line. This event was preceded by a mechanical failure of the feedback linkage whereby valve control was lost. It would appear, which was not evident at the time, that resonance of the valve with the fluid system caused excessive vibration levels in the valve itself to a point where fatigue failure of the linkage occurred.

Currently, due to the plug/trim change and the addition of hydraulic dampers in 1982, large valve stem movements and the resulting large induced pressure oscillations can not occur. However, as evidenced by recent failures of valve component studs (stem breakage), vibration induced fatigue is still occurring locally at the valve. Therefore, it is possible with the current arrangement that mechanical fatigue of a valve component could render the valve uncontrollable and initiate a water hammer event as was experienced in 1981.

The date of the events and contributing factors are summarized here.

a. November 5, 1976

Control valve instability; uncontrolled increase in feedwater flow rate either due to a malfunction in the feedwater regulator control or unbalanced forces in the valve itself.

Damage was mainly limited to the 'B' line outside containment and included instrument tubing and a valve actuator. Two snubber brackets attached to feedwater piping were found bent in the containment.

b. December 27, 1976
Control valve instability; valve instability caused by the plug design and mismatch of the valve system amplified the response to the system transient and the valve moved independent of the control signal.
Pressure oscillations were observed to be on the order of 400 psi.
Damage was limited to mainly instrument tubing on the outside containment 'B' line piping.

c. January 5, 1977
Control valve instability; valve again moved independently of control signal (opened despite signal to close).
Damage again was mostly limited to the 'B' outside containment piping which included instrument tubing and a damaged motor operator.
An instrumentation program was put into place.
Valve plug and trim changes were implemented on all three feedwater regulating valves.

d. May 6, 1981
Initiating cause of event was a disconnected feedback linkage on the 'A' feedwater regulating valve. This resulted in a large increase in feedwater flow to the 'A' steam generator followed by flow spikes in the 'B' and 'C' loops.
Damaged resulted to both the inside and outside containment piping on the 'A' feedwater line. This included damage to outside containment instrument tubing and a motor operator. Inside containment damage included bent snubber brackets and dislodged rupture restraint shims.

5.3.2.2 REVIEW OF NUREGS

Several NUREGS have been issued, mainly in the late 1970's, to compile and classify past water hammer events (i.e. NUREG-2059) [Ref.

9.25] and to define methods of evaluation (i.e. NUREG-2781) [Ref. 9.26].

As specifically related to feedwater control valve instability, water hammer can occur if the feedwater control valve is improperly sized, the control circuitry is improperly adjusted, closing and opening time is improperly adjusted or the system isn't filled and vented properly prior to startup. These factors were evaluated for their effect on BV-1.

Of these, the most significant water hammer event can be attributed to improper valve sizing. Unbalanced forces in the valve itself, created possibly due to cavitation, can be of sufficient magnitude on the plug and stem to overcome the force being applied by the actuator. This is the phenomenon considered to be associated with the water hammer events of 1976 and 1977.

A design change to replace the trim in 1977 on all three main feedwater regu ting valves was instituted. Subsequent monitoring through instrumentation installed both on the valves and feedwater piping showed that the trim change was effective in reducing the likelihood of reoccurrence of this event. Results of this study and evaluation of the feedwater regulating valve sizing to meet system requirements were submitted previously to the NRC [Ref. 9.22]

Subsequent changes at BV-1, including addition hydraulic dampers further minimizes the likelihood of feedwater control valve instability water hammer.

Water hammer events associated with rapid open or closure times or possibly improperly adjusted control circuitry are less severe. Analyses performed following the 1981 water hammer event in which a mechanical failure of the linkage was cited, showed that with a rapid closure of the valve (approx. .1 sec), loads of only approximately 5 kips axially on the horizontal inside containment piping could be produced [Ref 9.52]. Although bent snubber brackets were found, loads of this magnitude are insignificant in terms of pipe stress.

Therefore, due to resonance of the valve with the third standing wave (17 Hz) at 65% power on the 'A' line, future water hammer events may occur through a mechanical failure at the valve induced by this localized vibration. Future design considerations should take into account decoupling the valve stem/plug frequency from the third standing wave.

5.3.3 STEAM GENERATOR WATER HAMMER

Steam generator water hammer (SGWH) is a term used to describe a water hammer event initiating in the feedring of the steam generator. This event occurs when the feedring is partially voided, for example, following a feedwater isolation signal. Under this scenario steam is then drawn into the feedring establishing a steam/water interface. It is then possible that voids or pockets of steam can form. Subsequent cold water injection through auxiliary feedwater can cause this void to collapse such that a water slug moves rapidly into the void. When this slug impacts the incoming water filling the header, large hydraulic pressure waves can be created.

This phenomenon has been studied extensively by Creare and documented under NUREG-0291 [Ref. 9.31]. A steam generator water hammer event at Trojan will be cited due to its similarity to BV-1.

5.3.3.1 CREARE STUDY

Steam generator water hammer events occurred in the early 19?0's with the most notable event being at Indian Point. At that time bottom hole discharge in the feedring was used which meant that when the steam generator level dropped below the feedring as under a feedwater isolation signal, steam could be drawn into the line. Water hammer was then initiated.

As a result of these early events, four modifications were proposed to minimize the potential for occurrence and are listed here.

a. Top discharge through J-tubes. This entailed plugging the bottom discharge holes and installing J-tubes.

b. Minimization of horizontal length of piping from the feedring T section by installing a loop seal. The loop seal was to be installed as close to the steam generator as possible so as to minimize the length of horizontal run the slug could traverse thereby minimizing slug impact forces.

c. Minimization of time to initiate auxiliary feedwater injection. The effect of this is to minimize the amount of draining that could occur in the ring from the time main feedwater was isolated.

d. Institution of an upper limit on maximum auxiliary feedwater flow rates following a main feedwater isolation. This would minimize the likelihood of generating a slug and collapsing a steam void.

Of the above four items, a, b and c were implemented at BV-1. The fourth was not instituted. The justification for this was that testing was performed at Trojan [Refs. 9.68 and 9.69]. This testing was conducted with the a through c modifications in place at Trojan. The testing involved varying the auxiliary feedwater flow rates from approximately 200 to 440 gpm. The results of this testing showed that with these auxiliary feedwater flow rates steam generator water hammer was not induced.

It must be stated that provided feedring integrity is ensured (i.e., no source of out leakage) and the ring remains water solid, high auxiliary feedwater flow rates should be of no consequence. However, should the ring be allowed to drain through either cracked plugs in the bottom of the feedring or erosion of the thermal liner at the slip fit region in the steam generator nozzle, then the safety analysis performed by Trojan would be invalidated.

Through a review of the NUREG, the effect of a leakage hole in the feedring on the water level in the ring is quantified. For a

Westinghouse feedring and with feedwater isolated for only one minute (time it takes for auxiliary feedwater to initiate), should a leakage hole area equivalent to one hole be postulated it is shown that the water level height in the ring drops to approximately 81%. This alone would allow for a significant amount of steam to be drawn into the ring.

In addition, without an established upper bound as is presently the case at BV-1, auxiliary feedwater flow can be as high as 460 gpm at 100% power. This is far above the 150 to 200 gpm range cited for cold water injection in this system to minimize the potential for water hammer [Ref. 9.58].

Since significant loads, possibly on the order of 200 kips [Ref. 9.13], could propagate as a result of this phenomenon, steps should be taken to either periodically check the integrity of the feedring or institute an upper bound on auxiliary feedwater flow.

6.0 RESULTS OF ANALYSIS (POST 7R)

Global stratification was determined not to be a contributing mechanism for the 7R irregular deformation pattern, therefore, other potential root causes such as water hammer and past installation practices were reviewed. This entailed a review of existing industry information. During the root cause evaluation unanalyzed conditions were identified (i.e., monoballs locked and global stratification effects) and their effects were incorporated into analyses.

The results of the various analyses are summarized in this section of the report. These analyses were all performed after the seventh Beaver Valley Power Station-Unit 1 refueling outage (7R). Section 6.1 discusses the steps undertaken to ensure that the computer model agreed with recorded plant data. Sections 6.2 and 6.3 discuss the recently identified global stratification phenomenon. Section 6.4 investigates the effects of water hammer. Section 6.5 investigates the effects of local thermal stratification and Section 6.6 reviews possible pipe misalignment during the replacement of the cracked elbows adjacent to the steam generator.

6.1 CORRELATION OF ANALYTICAL MODEL TO PLANT DATA

The correlation of the analytical model to the plant data was performed in several steps. The first step was to develop a STRUDL-SW [Ref.9.44] piping model based on the NUPIPE-SW [Ref. 9.45] piping model of record. See the attached STRUDL-SW piping models (Figures 6.1-1, 2 and 3 for loops A, B and C respectively). The piping geometry is modeled on STRUDL-SW because this program has the capability to analyze a top to bottom temperature differential over some or all of the elements in the model. The next step was to benchmark the STRUDL-SW model to the existing NUPIPE-SW run of record model for the 100% power level operation mode. The displacement agreement between the two models was excellent. See Figures 6.1-4 and 6.1-5 for the displacement profile from the non-stratified thermal cases. The remaining steps involved correlation of the recorded plant data (gathered in Action Plan, Section 4.5, Implementation of Instrumentation Program) with the results from STRUDL-SW analysis. This was done to verify the base model before global stratification analysis could be performed. The correlations performed and results are discussed in the

STRUDL-SW LOOP A MODEL

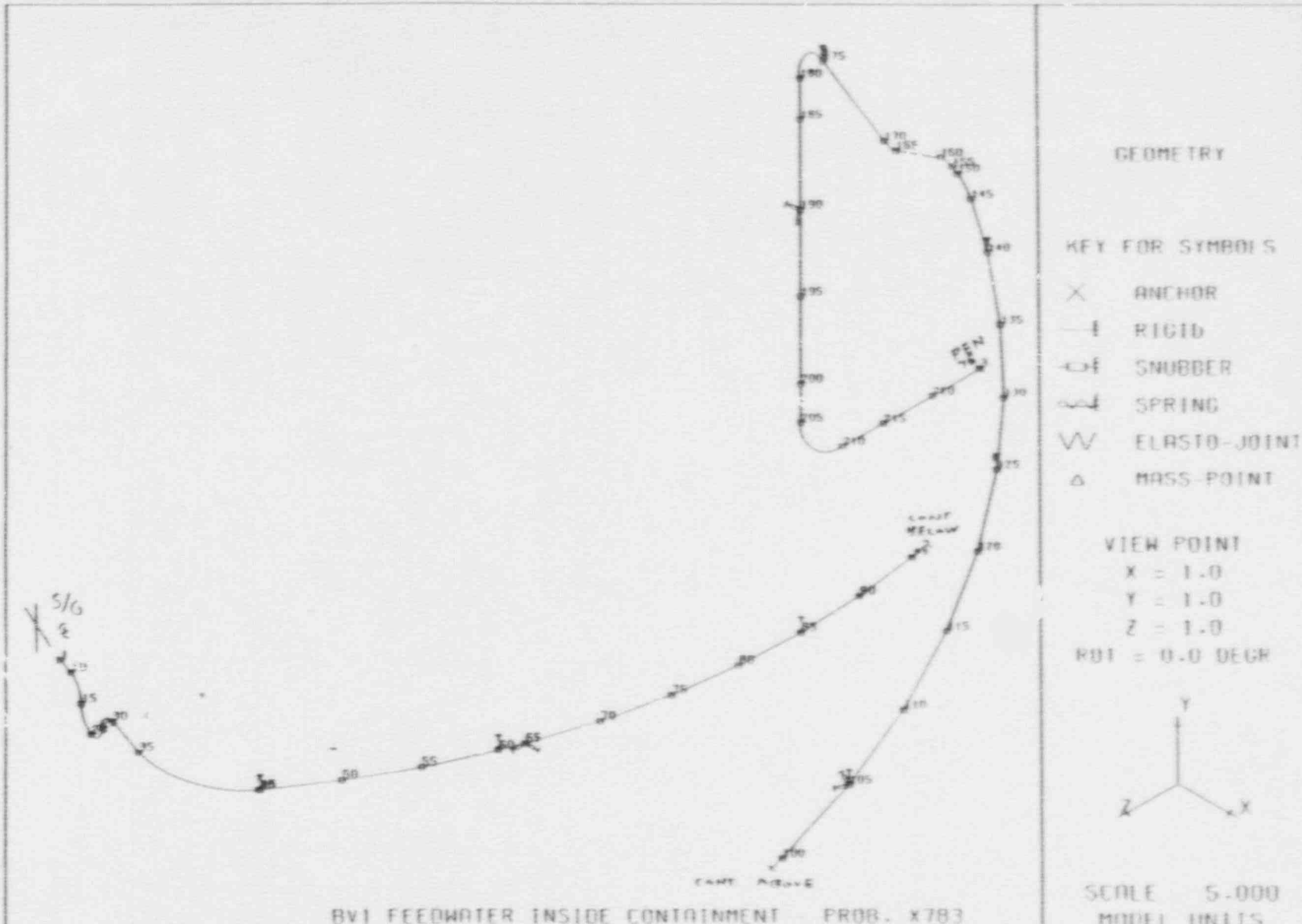


FIGURE 6.1-1

STRUDL-SW LOOP A MODEL (cont.)

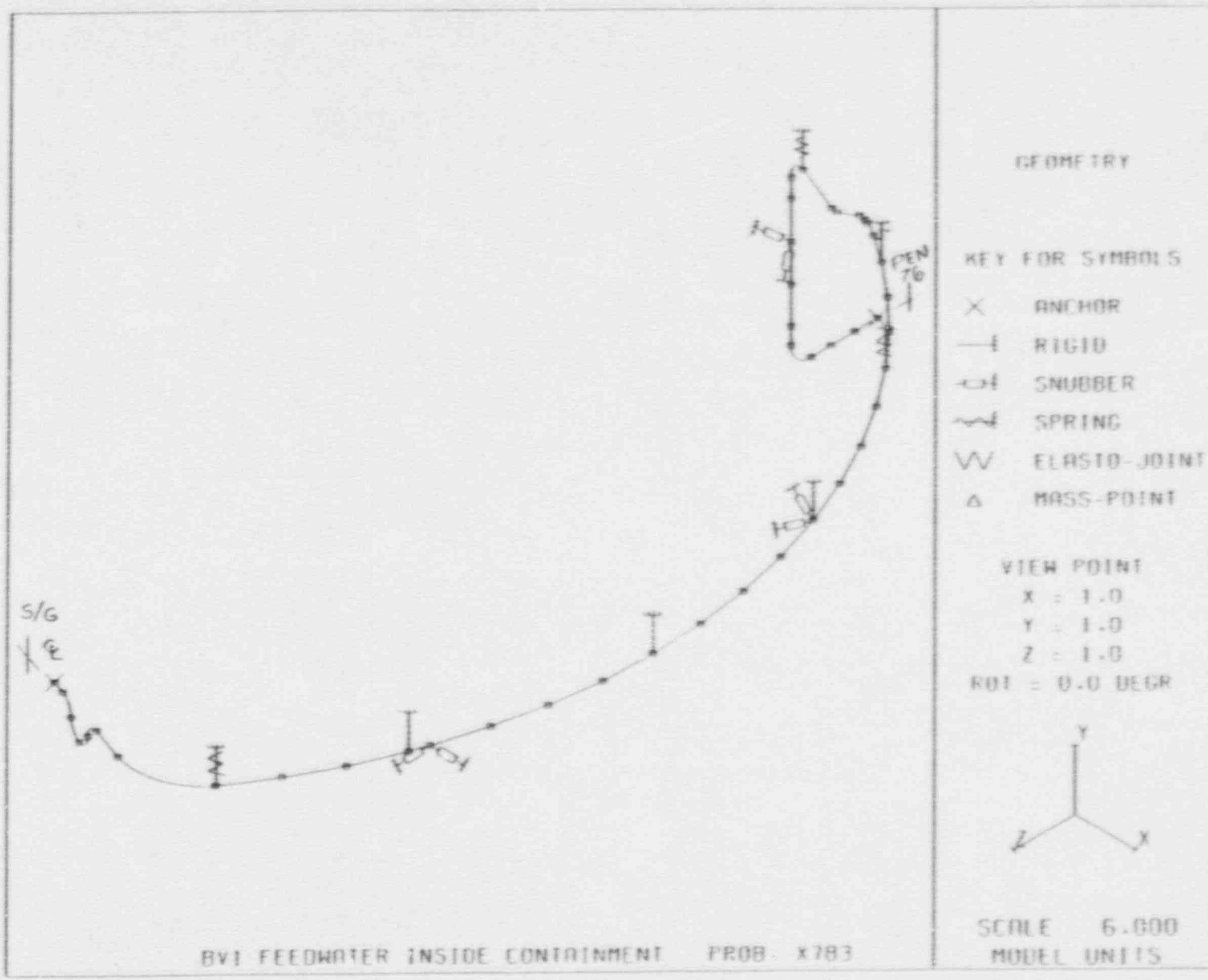


FIGURE 6.1-1

STRUDL-SW LOOP B MODEL

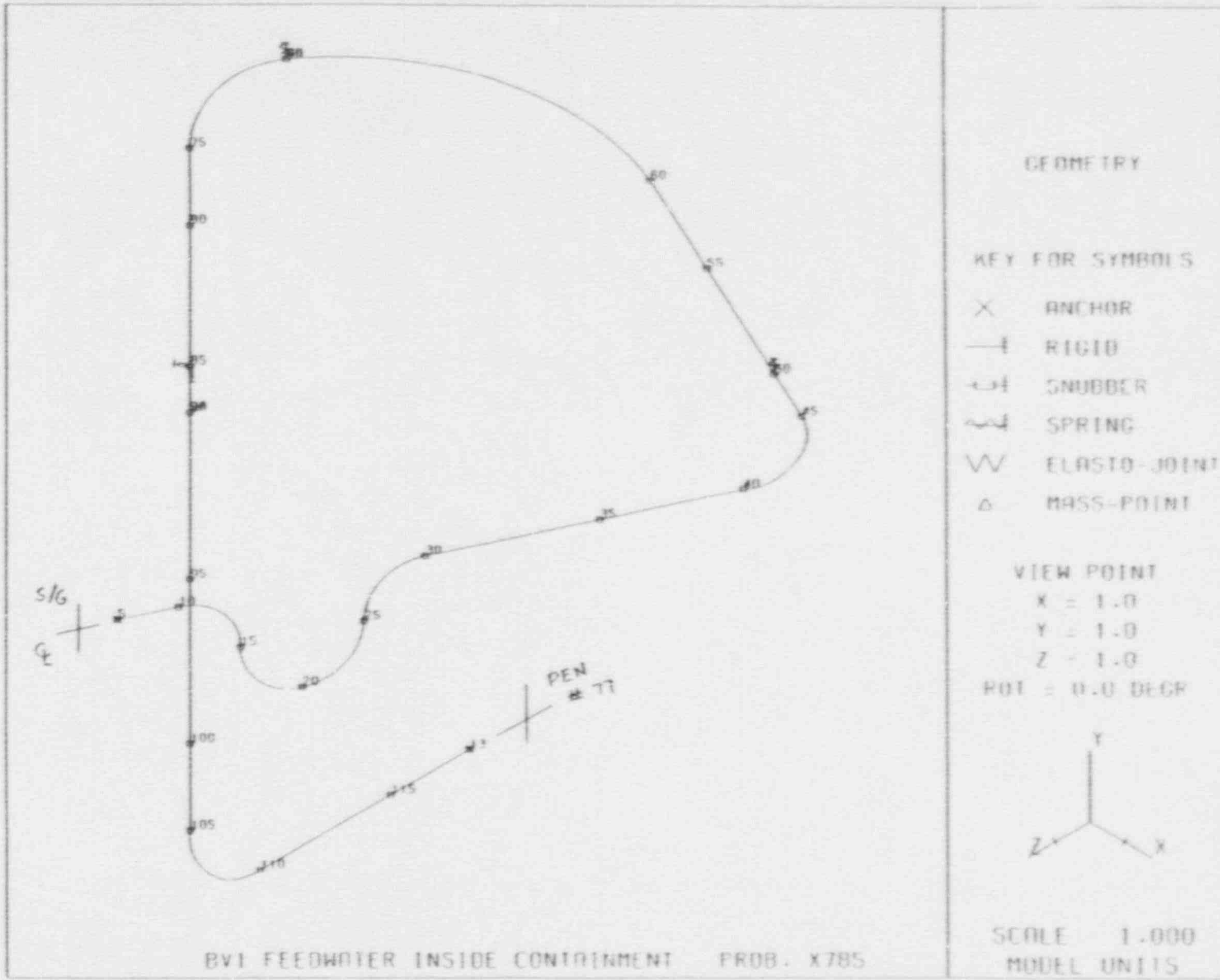


FIGURE 6.1-2

STRUDL-SW LOOP B MODEL (cont.)

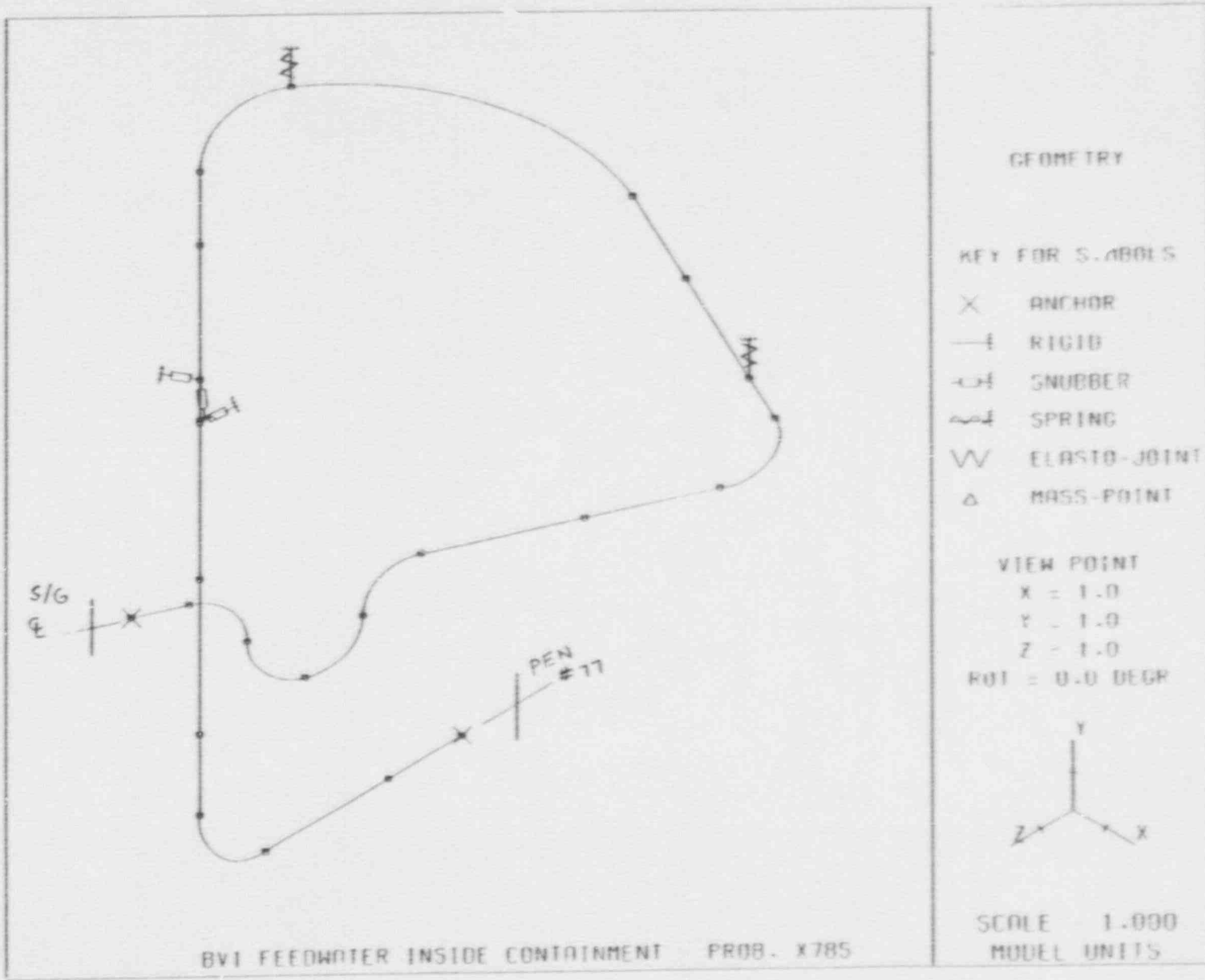


FIGURE 6.1-2

STRUDL-SW LOOP C MODEL

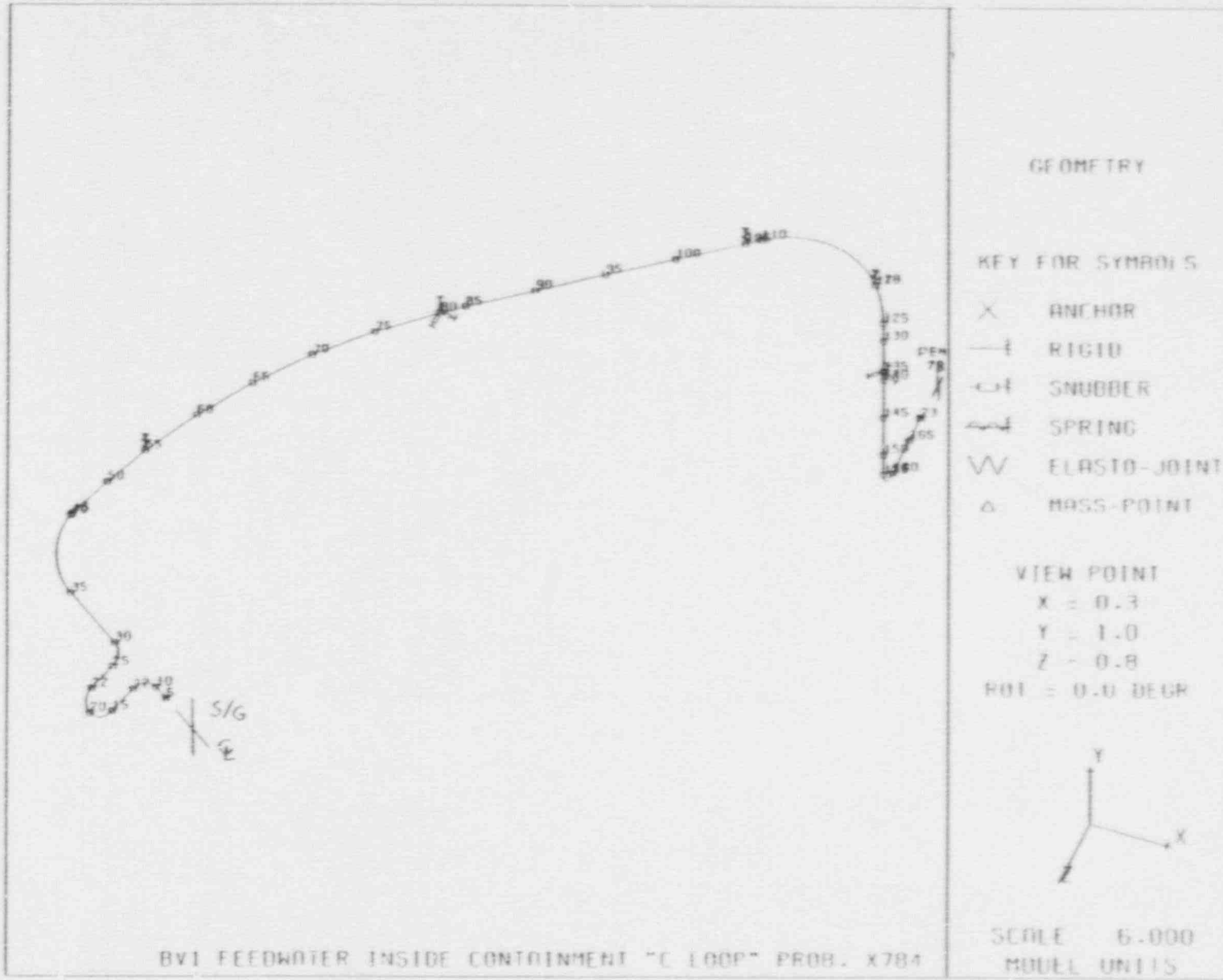


FIGURE 6.1-3

STRUDL-SW LOOP C MODEL (cont.)

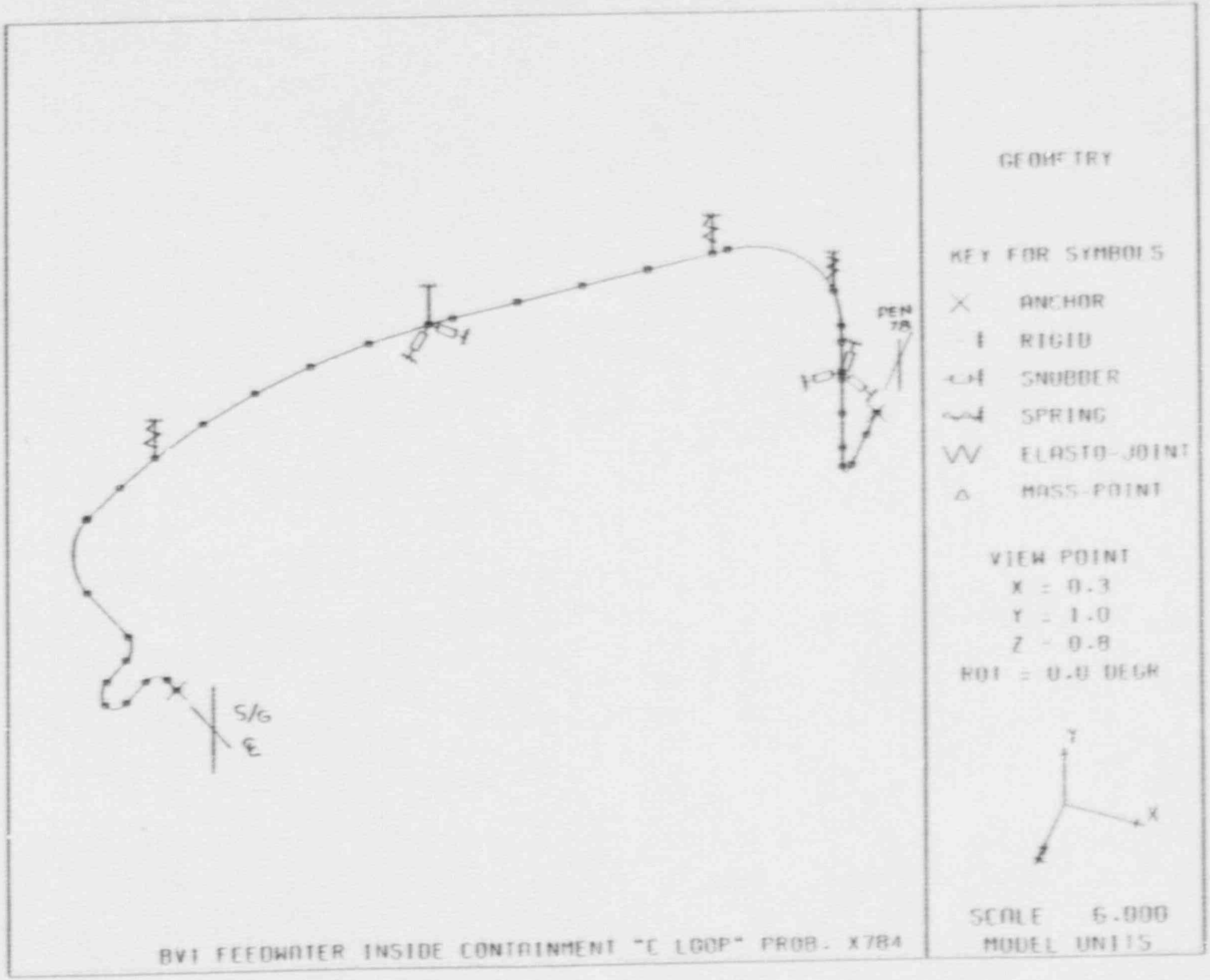


FIGURE 6.1-3

NON-STRATIFIED PIPE PROFILE 441° F

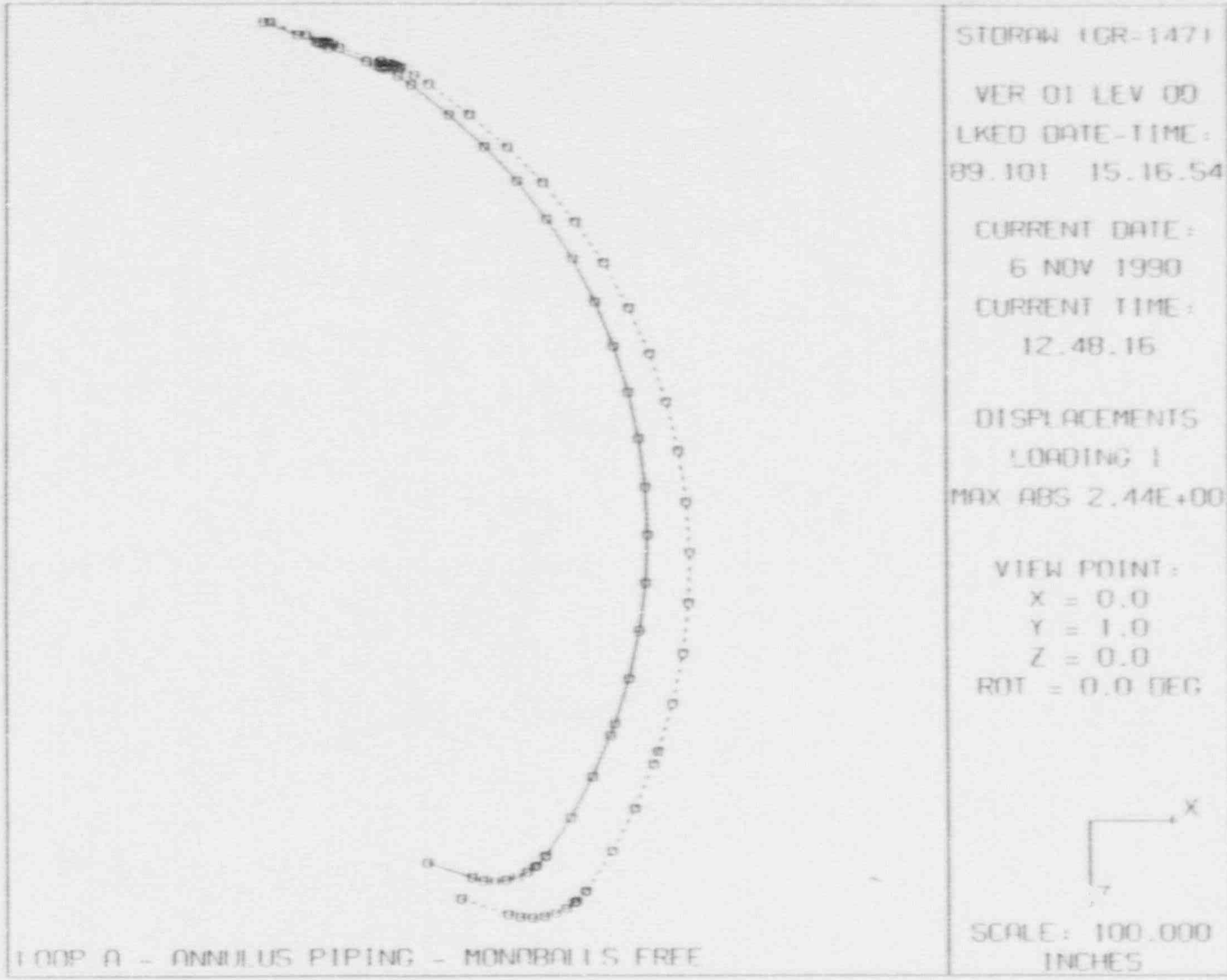


FIGURE 6.1-4

NON-STRATIFIED PIPE PROFILE 441° F (CONT)

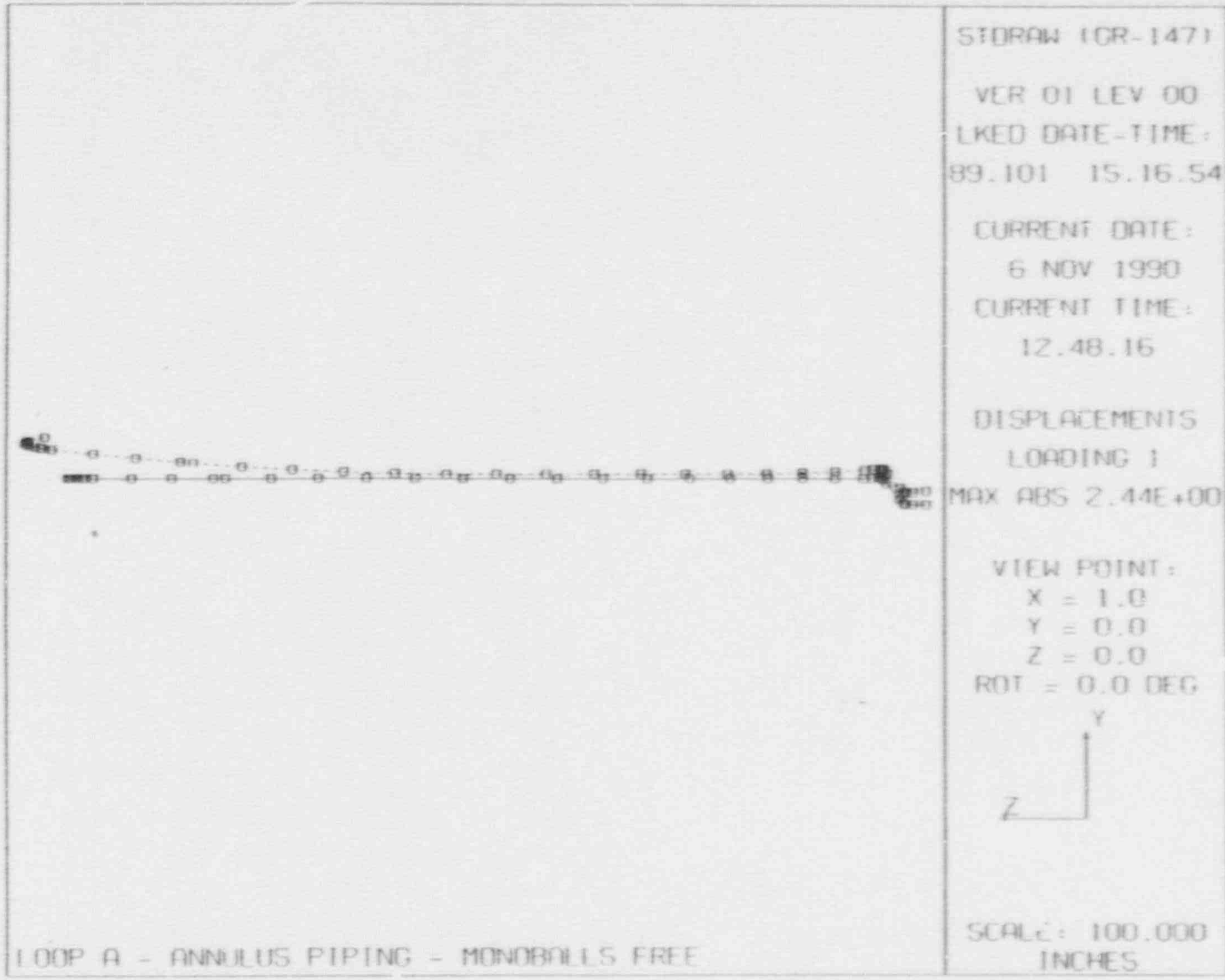


FIGURE 6.1-4

NON-STRATIFIED PIPE PROFILE 32° F

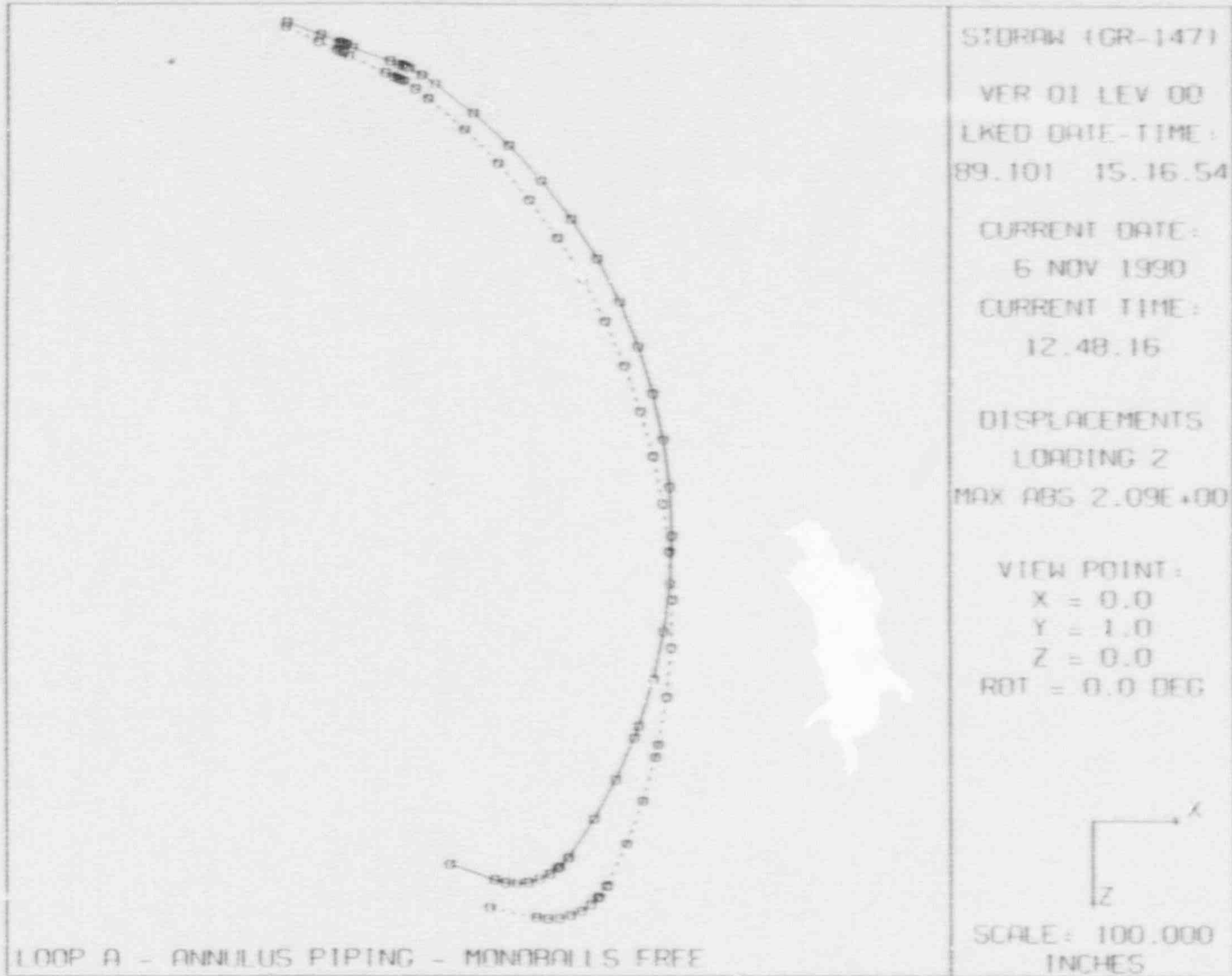


FIGURE 6.1-5

NON-STRATIFIED PIPE PROFILE 32° F (CONT)

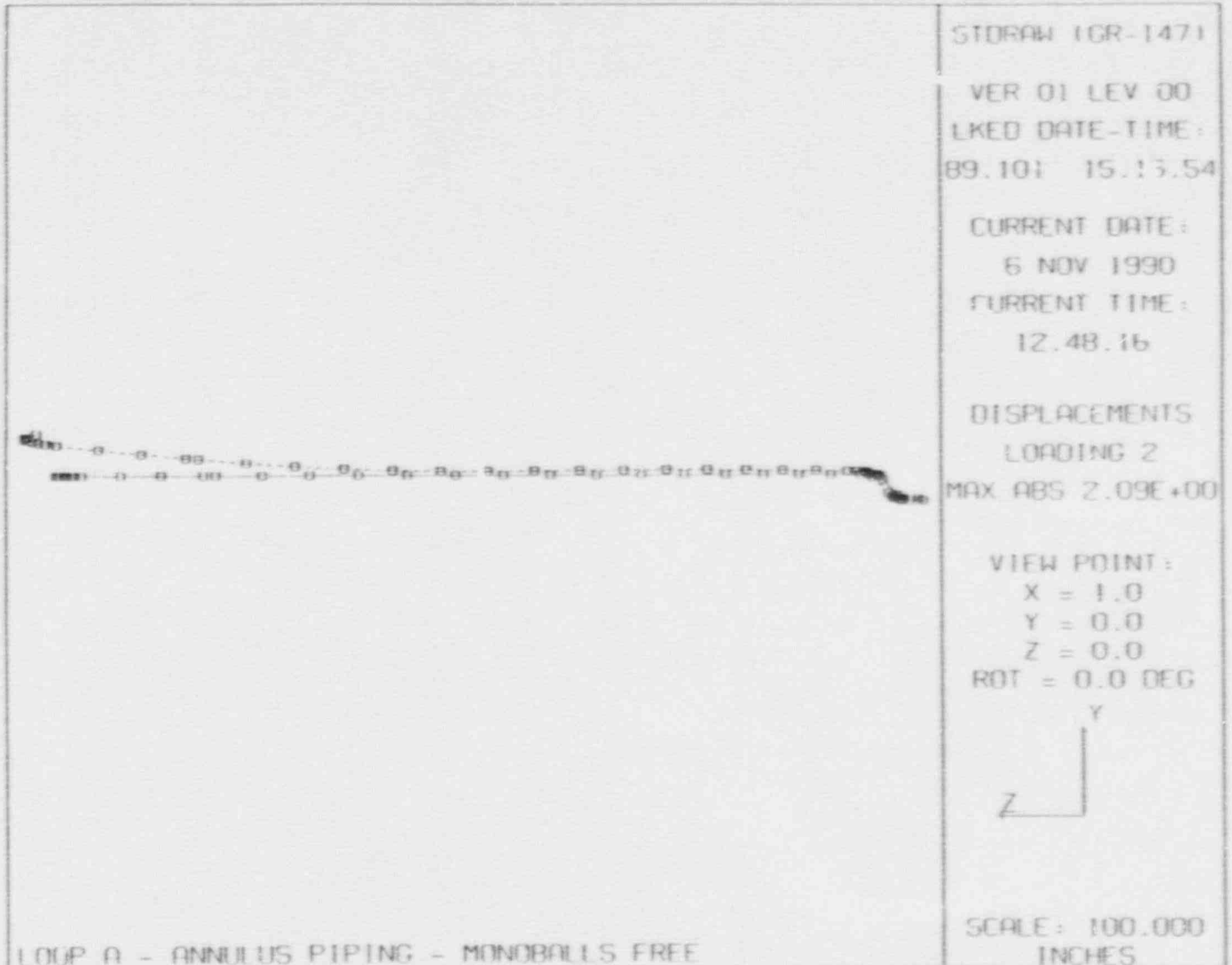


FIGURE 6.1-5

following two sections entitled Normal Thermal Movements and Incorporation of Global Stratification. Only loop A displacement data were recorded during the power ascension from 7R. All conclusions drawn from the evaluation of loop A data are applied to the analysis of loops B and C where applicable.

In addition to the licensing basis STRUDL-SW finite element model results, a personal computer version of ANSYS [Ref. 9.46] was utilized. Excellent agreement between the two computer codes was obtained for all the postulated thermal stratification scenarios [Ref. 9.47].

6.1.1 NORMAL THERMAL MOVEMENT

Initial attempts at correlating the recorded normal thermal displacements with the STRUDL-SW model were unsuccessful considering the as-designed support functions. The monoball supports are designed as vertical only supports. The single trunion ball and socket design on sliding plates is intended to provide freedom of movement in the other five degrees of freedom. A second series of computer runs were performed with the monoballs locked in both the lateral and axial directions and allowing free rotational movement. The correlation between the STRUDL-SW model with the monoballs locked and the plant recorded data was very good (see Table 6.1.1-1). Therefore the interim qualification of the feedwater piping analysis was performed considering the monoballs locked (acting as 3-way constraints) as well as unlocked (acting as vertical constraints only). For the long term solution the monoballs will be addressed as stated in Section 8.1.2.4.

6.1.2 INCORPORATION OF GLOBAL STRATIFICATION

Two separate cases of global stratification were considered in this analysis. Both of these scenarios were experienced during the recent post 7R heatup. The first global stratification case is auxiliary feedwater injection after a reactor trip at 29% power. The second case is described as significant intrasystem stratification (stratification caused by two different temperature fluids within the feedwater system). This occurs when feedwater flow is reduced. These two cases are discussed in detail in Sections 6.1.2.1 and 6.1.2.2 respectively.

TABLE 6.1.1-1

STRUDL-SW VS PLANT DISPLACEMENT DATA (LOOP A)
REACTOR POWER LEVEL AT 29% AND FEEDWATER TEMPERATURE OF 335°F

Lanyards	STRUDL Joint	Measured Global Displacements		STRUDL Global Displacements	
1, 2 & 3	45	X	1.41"	X	1.90"
		Y	1.34"	Y	1.00"
		Z	1.34"	Z	1.43"
7 & 8	125	X	0.09"	X	0.21"
		Z	-0.66"	Z	-0.59"

The approximations made in the STRUDL-SW evaluation and the inherent variations in field measured data make it unreasonable to expect an exact correlation between recorded and calculated displacements. The displacements shown above indicate as good a correlation as should be expected.

6.1.2.1 AUXILIARY FEEDWATER INJECTION AFTER 29% POWER REACTOR TRIP

After the reactor trip the feedwater line was at approximately 335° F. Auxiliary feedwater at about 45° F was injected into the system and the line thermally stratified.

Initial attempts at correlating the recorded auxiliary feedwater injection global stratification movements with the monoballs free to move as designed (see Section 6.1.1) with recorded data were unsuccessful. The pipe moved opposite to the predicted direction. This problem was also experienced in the Section 6.1.1 (normal thermal movement) correlation. The best correlation of data occurs when the monoballs are locked in the axial and lateral directions (see Table 6.1.2.1-1).

6.1.2.2 INTRASYSTEM STRATIFICATION

Intrasystem global stratification can occur anytime during plant operation, but significant intrasystem thermal stratification has only been observed during power reduction (and subsequent feedwater flow reduction) at power levels less than or equal to 29%. The feedwater regulating valves are bypassed at low power operation (normally 15% to 30%) and condensate is obtained directly from the condenser hotwell. When the feedwater line is hot and flow to the steam generators is reduced the feedwater lines will stratify (see Figure 6.1.2.2-1). The maximum intrasystem global stratification is considered to be enveloped by the maximum auxiliary feedwater injection case because a larger stratification potential exists for the auxiliary feedwater case. Stratification potential is defined as the maximum feedwater temperature minus the minimum auxiliary feedwater temperature (see Section 6.2). The maximum potential for intrasystem stratification is 255° F. This is a result of a feedwater temperature of 335° F at 29% power and a condenser hotwell temperature of 80° F. All conclusions drawn from the displacement correlation in loop A data are applied in the remaining two loops. Instrumentation was not installed in loops B and C.

TABLE 6.1.2.1-1

STRUDL-SW VS PLANT DISPLACEMENT DATA (LOOP A)
AUXILIARY FEEDWATER INJECTION

Lanyards	STRUDL Joint	Measured Global Displacements		STRUDL Global Displacements	
1, 2 & 3	45	X	1.19"	X	1.72"
		Y	0.04"	Y	-0.66
		Z	0.89"	Z	0.82"
7 & 8	125	X	0.22"	X	0.38"
		Z	-0.51"	Z	-0.47"

The approximations made in the STRUDL-SW evaluation and the inherent variations in field measured data make it unreasonable to expect an exact correlation between recorded and calculated displacements. The displacements shown above indicate as good a correlation as should be expected.

INTRASYSTEM STRATIFICATION GRAPH
(Recorded Plant Data)
See Figure 4.5-1 for Thermocouple Locations

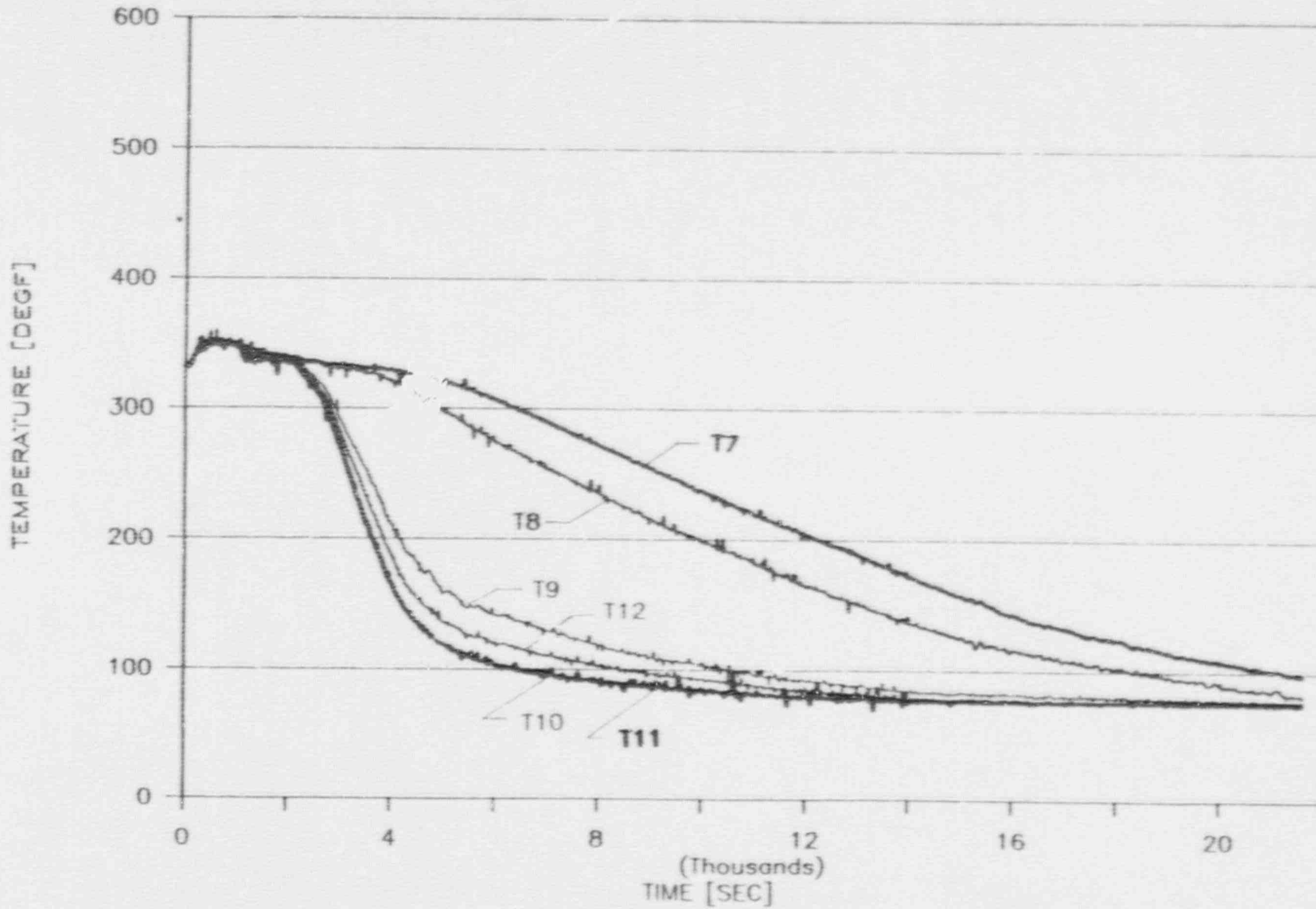


FIGURE 6.1.2.2-1

6.2 NEW GLOBAL STRATIFICATION LOAD CASES (NOT PREVIOUSLY CONSIDERED)

New global stratification cases have been developed. These new cases have never before been considered as part of the design basis for PWR feedwater system piping in any plant. These cases envelope the effects of postulated thermal stratification. See Figure 6.2-2 for sample displacement profiles caused by thermal stratification effects. These cases are based on the extrapolated case of the recorded auxiliary feedwater injection at 29% power and the maximum potential temperature difference. The maximum feedwater temperature of 441° F is at the 100% power level. If a reactor trip occurred in the winter, the temperature of the fluid in the safety related demineralized water tank WT-TK-10 located in the yard, heated only by space heaters, could be as low as 45° F. The auxiliary feedwater system would inject the 45° F water into the 441° F feedwater system. The temperature difference of 396° F would not be realized based on two recorded temperature differential cases [Ref. 9.41 and Appendix 10.1]. During the more significant case of the two [Ref.9.41], the feedwater line was at 335° F and the auxiliary feedwater line was considered to be 45° F (actual water temperature was later determined to be 50° F) . The potential for 290° F stratification existed, however, only 180° F [250° F (top of pipe) - 70° F (bottom of pipe)] stratification was realized. This resulted in a 62% scale factor [180/290] (see Figure 6.2-1). This scale factor is applied to the full range potential stratification or 0.62 x (441-45) = 245° F. All horizontal piping was conservatively considered to have the potential to be stratified at 245° F. Piping with vertical components (e.g., risers) are considered to be unstratified in the model. See References 9.7, 9.8 and 9.9 for the specific global thermal stratification profiles that constitute the new global stratification cases.

6.3 PRESENT CONFIGURATION-GLOBAL STRATIFICATION AND CONSTRAINED MONOBALL SUPPORTS EXTRAPOLATED TO DESIGN BASIS TEMPERATURES

After the magnitude of the global stratification temperature was determined, it was considered in the three STRUDL-SW models. Loops A and C both have monoballs. Since the monoballs in loop A were postulated to be acting as 3-way supports [axial/lateral restraints as well as their as-designed vertical function] loop A -1

AFW INJECTION STRATIFICATION GRAPH
(Recorded Plant Data)
See Figure 4.5-1 for Thermocouple Locations

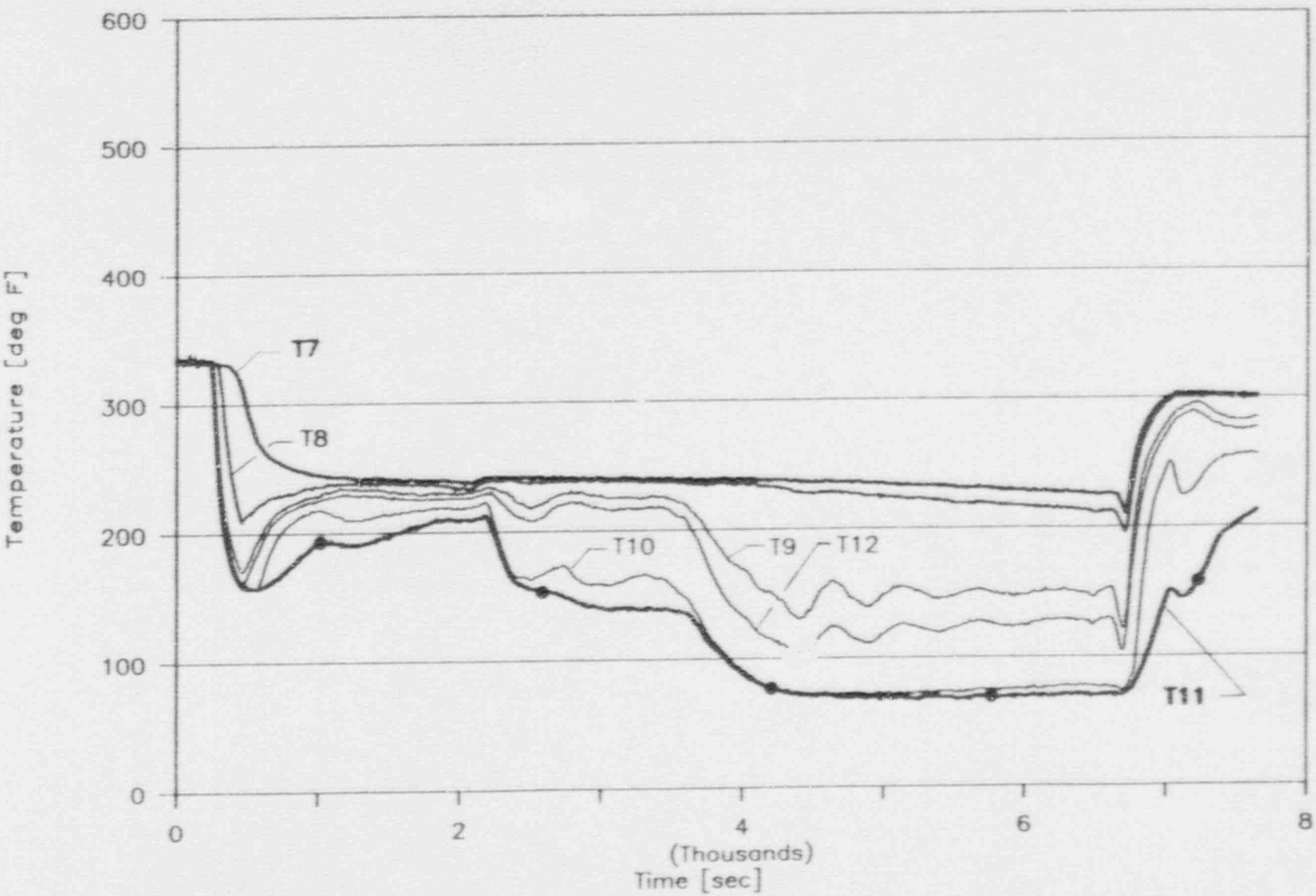


FIGURE 6.2-1

STRATIFIED PIPE PROFILE

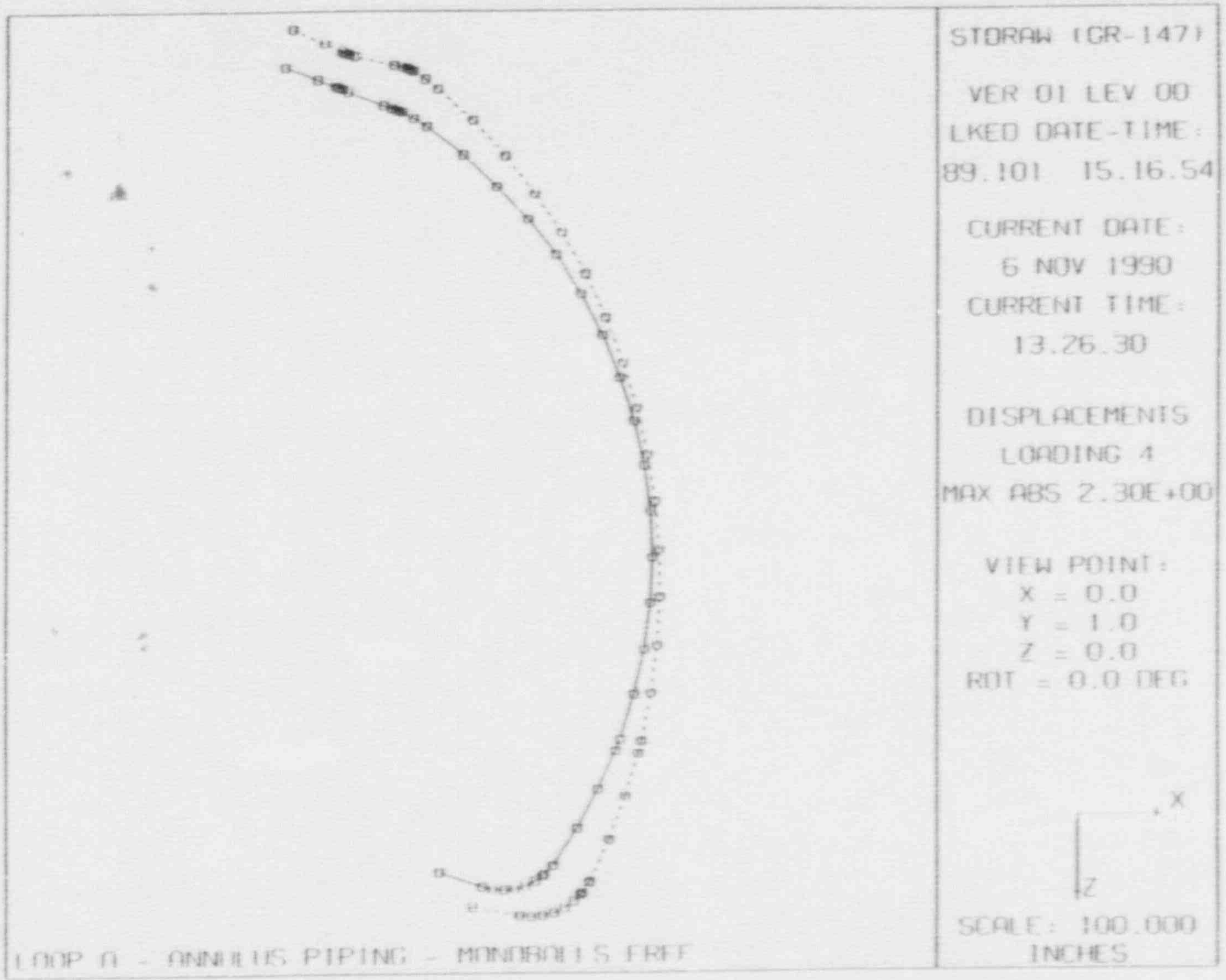


FIGURE 6.2-2

STRATIFIED PIPE PROFILE (CONT)

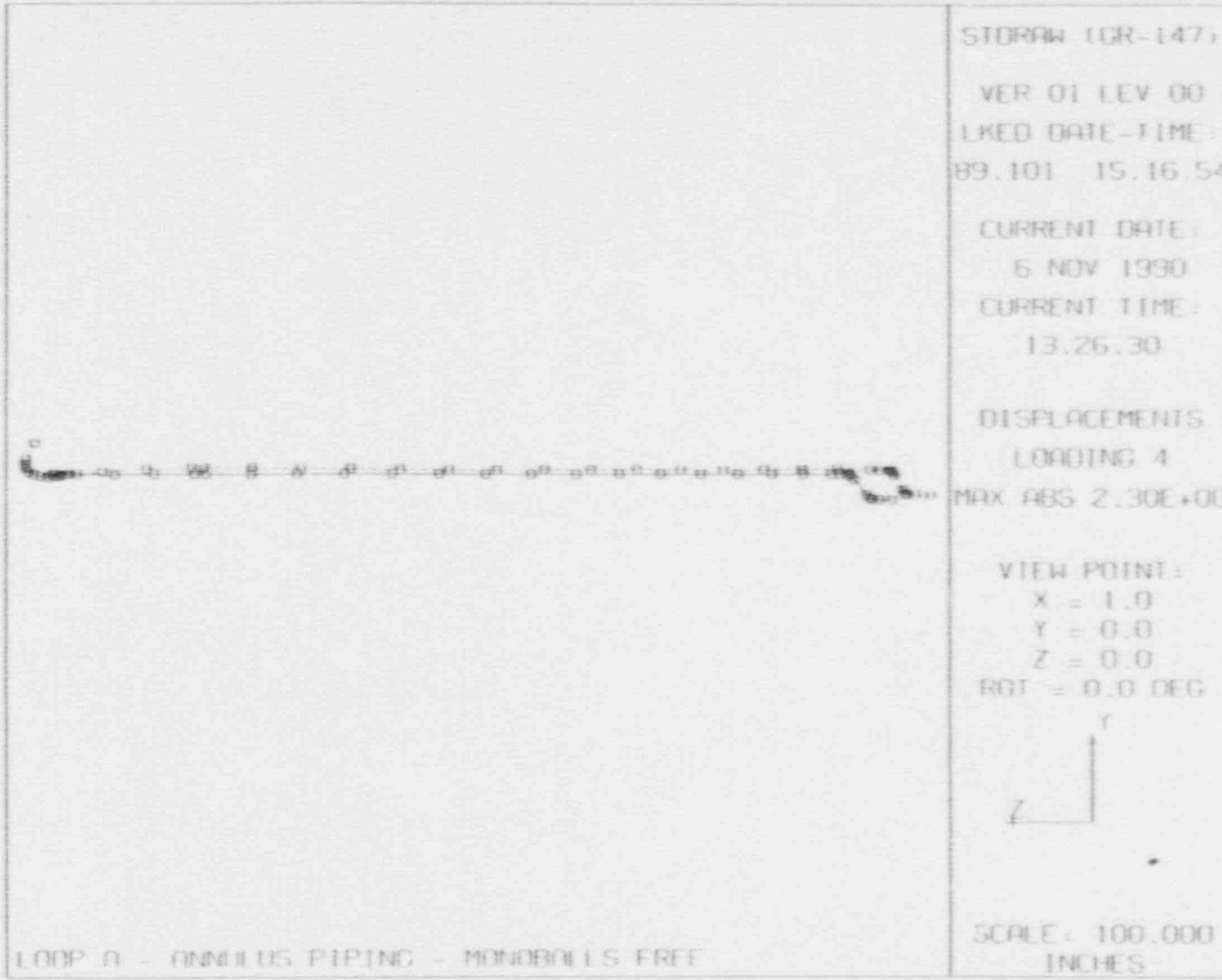


FIGURE 6.2-2

was analyzed twice (considering the monoballs once as a three way and once as a vertical). In the absence of recorded data, loop C was also analyzed twice (once with the monoball as a three way and once as a ve) ical). The results of pipe stress analyses [Refs. 9.7, .8 and 9.9] for all three loops were determined to be within the original plant design basis allowables in accordance with ANSI B31.1 - 1967. The stress analysis of the feedwater piping considers both the global thermal stratification moments generated along the axis of the pipe as well as the circumferential stress generated in the piping due to the hotter top of the piping expanding more than the cooler bottom [see Figure 6.3-1]. The circumferential stress is an internal stress and does not produce external loads. Tables 6.3-1, 6.3-2 and 6.3-3 contain the pertinent pipe stress analytical results and load combinations for loops A, B and C respectively.

Global thermal stratification is the only loading condition where the feedwater piping closes the gaps at pipe rupture restraints. This does not occur under any other loading condition (i.e., design basis fluid transient or seismic event) unless that loading conditions occurs concurrently with global stratification. The loadings generated at the restraints by stratification are significantly less than the design basis loads developed by pipe break scenarios. Stress levels used to evaluate pipe break locations were impacted by the consideration of global stratification effects. No additional break locations or restraint requirements were identified utilizing the guidelines provided in Reference 9.6.

Pipe support analyses [Refs. 9.48 and 9.56] indicate that all of the existing pipe supports, except for monoball supports [H-3 and H-4 (loop A)] and one sprir hanger [SH-6 (loop A)] passed their design basis code equations. See Tables 6.3-4, 6.3-5 and 6.3-6 for the pipe support results for loops A, B and C respectively. ASME Boiler and Pressure Vessel Code Case N-318 was used to analyze the local pipe wall stresses for spring hanger SH-6. ASME Section III Appendix F rules were used to show interim acceptability of the supports H-3 and H-4. Several inspections of snubbers and hanger frames are also required to confirm assumptions [see Tables 6.3-4, 6.3-5 and 6.3-6]. Snubbers to be as-built are HSS-201, HSS-202, HSS-203, HSS-204, HSS-205, HSS-206, HSS-212 and HSS-212A. Frames to be as-built are H-3, H-4, H-5 and H-11.

CIRCUMFERENTIAL STRESS DISTRIBUTION DUE TO TOP TO BOTTOM TEMPERATURE GROWTH

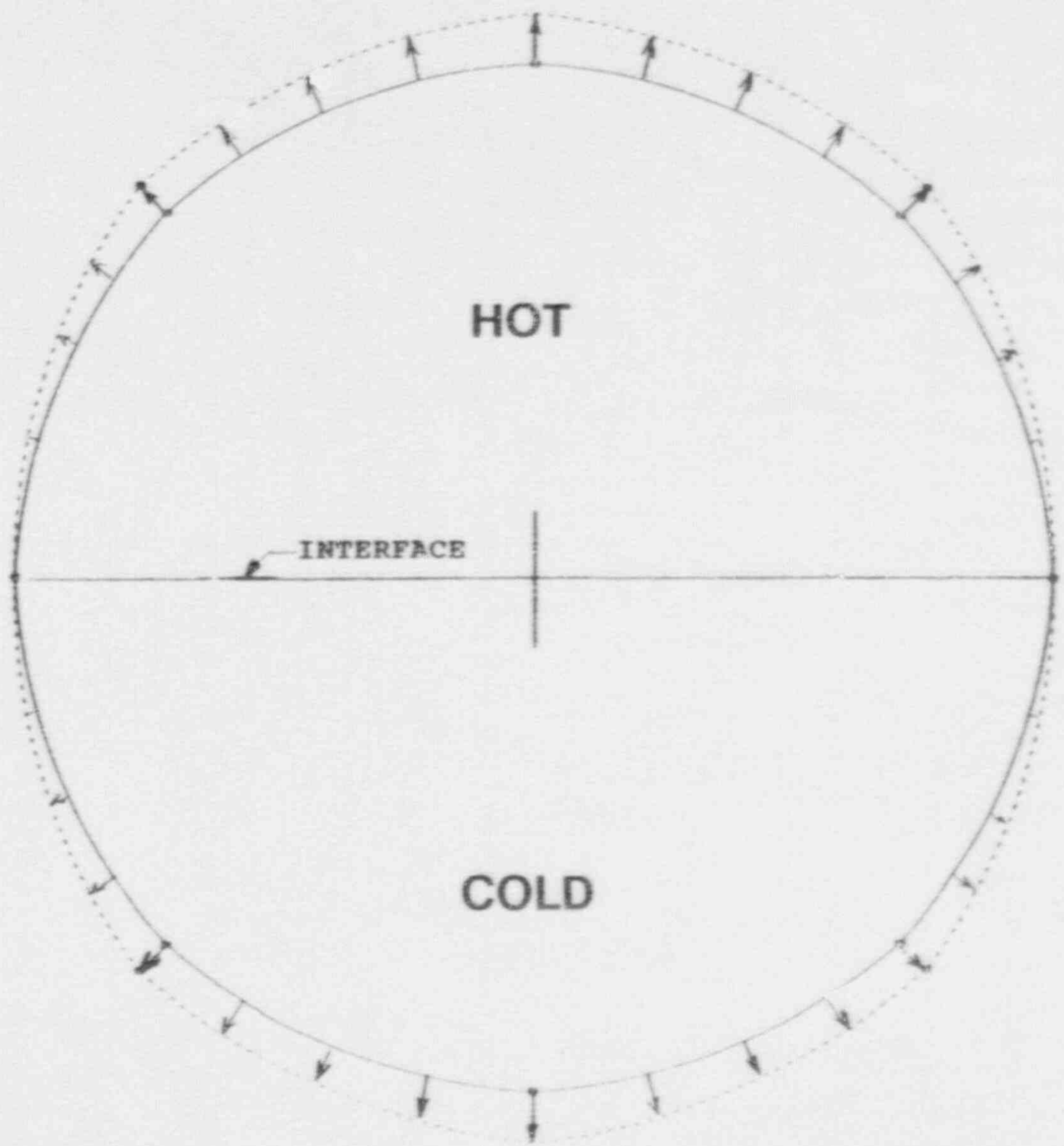


FIGURE 6.3-1

TABLE 6.3-1

PIPE STRESS ANALYSIS RESULTS LOOP A

LOAD COMBINATION	MAXIMUM CALCULATED STRESS***	ANSI B31.1 ALLOWABLE STRESS	FACTOR OF SAFETY ******	MONOBALL CONDITION (JOINT)*
LP + DL	7052 PSI	15000 PSI	2.13	FREE**** (75)
LP + DL + OBEA + SRSS(OBEI,TH)	15903 PSI	18000 PSI	1.13	FREE**** (10)
LP + DL + SRSS(SSEI,TH)	11482 PSI	36000 PSI	3.13	LOCKED** (160)
***** THER	24764 PSI	22500 PSI	0.91 *****	LOCKED** (205)
***** LP + DL + THER	30908 PSI	37500 PSI	1.21	LOCKED** (205)
CTD + H	17846 PSI	37500 PSI	2.10	LOCKED** (30)

* The joint listed is the point where the maximum stress occurred. All joints were checked for all loadings.

** "Locked" refers to the analysis performed considering monoballs R-3 and R-4 as three way restraints (vertical, lateral & axial).

*** Maximum stress from either the "Free" or "Locked" monoball case.

**** "Free" refers to the analysis performed considering the monoballs R-3 and R-4 as vertical restraints only (as designed).

***** Either criteria may be satisfied. Therefore, the overstress of the THER criteria is acceptable based on the LP+DL+THER stress level.

****** (Allowable Stress)/(Calculated Stress)

Loading Conditions Analyzed

Deadload	(DL)
Operational Basis Earthquake Inertia	(OBEI)
Operational Basis Earthquake Anchor Movements	(OBEA)
Design Basis Earthquake Inertia	(DBEI)
Circumferential Temperature Distribution	(CTD)
Time History	(TH)
Thermal Expansion (including stratification effects)	(THER)
Longitudinal Pressure	(LP)
Hoop Stress	(H)

TABLE 6.3-2

PIPE STRESS ANALYSIS RESULTS LOOP B

LOAD COMBINATION	MAXIMUM CALCULATED STRESS ****	ANSI B31.1 ALLOWABLE STRESS	FACTOR OF SAFETY ***	JOINT*
LP + DL	6433 PSI	15000 PSI	2.33	75
LP + DL + OBEA + SRSS(OBEI,TH)	14095 PSI	18000 PSI	1.28	10
LP + DL + SRSS(SSEI,TH)	10167 PSI	36000 PSI	2.66	75
** THER	22791 PSI	22500 PSI	0.91 **	75
** LP + DL + THER	29225 PSI	37500 PSI	1.28	75
CTD + H	16310 PSI	37500 PSI	2.30	10

* The joint listed is the point where the maximum stress occurred. All joints were checked for all loadings.

** Either criteria may be satisfied. Therefore, the overstress of the THER criteria is acceptable based on the LP+DL+THER stress level.

*** (Allowable Stress)/(Calculated Stress)

**** Maximum stress from either the "Free" or "Locked" monoball case.

Loading Conditions Analyzed

Deadload	(DL)
Operational Basis Earthquake Inertia	(OBEI)
Operational Basis Earthquake Anchor Movements	(OBEA)
Design Basis Earthquake Inertia	(DBEI)
Circumferential Temperature Distribution	(CTD)
Time History	(TH)
Thermal Expansion (including stratification effects)	(THER)
Longitudinal Pressure	(LP)
Hoop Stress	(H)

TABLE 6.3-3

PIPE STRESS ANALYSIS RESULTS LOOP C

LOAD COMBINATION	MAXIMUM CALCULATED STRESS ******	ANSI B31.1 ALLOWABLE STRESS	FACTOR OF SAFETY *****	MONOBALL CONDITION (JOINT)*
LP + DL	10508 PSI	15000 PSI	1.90	FREE*** (10)
LP + DL + OBEA + SRSS(OBEI,TH)	15347 PSI	18000 PSI	1.17	FREE*** (10)
LP + DL + SRSS(SSEI,TH)	12955 PSI	36000 PSI	2.08	FREE** (10)
**** THER	22026 PSI	22500 PSI	1.02	LOCKED** (125)
**** LP + DL + THER	28716 PSI	37500 PSI	1.31	LOCKED** (125)
CTD + H	16310 PSI	37500 PSI	2.19	(10)

* The joint listed is the point where the maximum stress occurred. All joints were checked for all loadings.

** "Locked" refers to the analysis performed considering monoball R-11 as a three way restraint (vertical, lateral & axial).

*** "Free" refers to the analysis performed considering the monoball R-11 as a vertical restraint only.

**** Either criteria may be satisfied.

***** (Allowable Stress)/(Calculated Stress)

****** Maximum stress from either the "Free" or "Locked" monoball case.

Loading Conditions Analyzed

Deadload	(DL)
Operational Basis Earthquake Inertia	(OBEI)
Operational Basis Earthquake Anchor Movements	(OBEA)
Design Basis Earthquake Inertia	(DBEI)
Circumferential Temperature Distribution	(CTD)
Time History	(TH)
Thermal Expansion (including stratification effects)	(THER)
Longitudinal Pressure	(LP)
Hoop Stress	(H)

TABLE 6.3-4

PIPE SUPPORT RESULTS - LOOP A

SUPPORT NUMBER	QUALIFIED FOR	CONFIRMATION REQUIRED	NOTES	ACTION REQUIRED
WFPD-SH-1	DESIGN BASIS	NO		
WFPD-SH-2	DESIGN BASIS	NO		
WFPD-R-3	INTERIM	NO	Appendix F for bolt allowables Appendix F for member shear allowables IWA - OBE loads compared to DBE allowables	JCO Walkdown required
WFPD-R-4	INTERIM	YES	IWA - OBE loads compared to DBE allowables Con Reqd for use of 60% CTD stress	JCO Results of data collection Walkdown required
WFPD-R-5	DESIGN BASIS	NO		Walkdown required
WFPD-SH-6	INTERIM	NO	CCN 318 used for IWA analysis	
WFPD-SH-7	DESIGN BASIS	NO	Secondary bending divided by 2 for IWA analysis	
WFPD-HSS-201	DESIGN BASIS	YES	6.2° swing angle Con Reqd for piston setting	Walkdown required
WFPD-HSS-202	DESIGN BASIS	YES	Con Reqd for piston setting	Walkdown required
WFPD-HSS-203	DESIGN BASIS	YES	5.2° swing angle Con Reqd for piston setting	Walkdown required
WFPD-HSS-204	DESIGN BASIS	YES	Con Reqd for piston setting	Walkdown required
WFPD-HSS-205	DESIGN BASIS	YES	Con Reqd for piston setting	Walkdown required
WFPD-HSS-206	DESIGN BASIS	YES	Con Reqd for piston setting	Walkdown required

Note: The loads include the effects of global thermal stratification and postulated locked monoballs.

TABLE 6.3-5

PIPE SUPPORT RESULTS - LOOP B

SUPPORT NUMBER	QUALIFIED FOR	CONFIRMATION REQUIRED	NOTES	ACTION REQUIRED
WFPD-SH-8	DESIGN BASIS	NO		
WFPD-SH-9	DESIGN BASIS	NO		
WFPD-HSS-207	DESIGN BASIS	NO	Primary loads divided by 2 for PITRIFE	
WFPD-HSS-208	DESIGN BASIS	NO	Primary loads divided by 2 for PITRIFE	
WFPD-HSS-208A	DESIGN BASIS	NO		

Note: The loads include the effects of global thermal stratification

TABLE 6.3-6

PIPE SUPPORT RESULTS - LOOP C

SUPPORT NUMBER	QUALIFIED FOR	CONFIRMATION REQUIRED	NOTES	ACTION REQUIRED
WFPD-SH-10	DESIGN BASIS	NO		
WFPD-R-11	DESIGN BASIS	YES	Con Reqd for use of 60% CTD stress	Walkdown required Results of data collection
WFPD-SH-12	DESIGN BASIS	NO	Spring 1/8" out of range	
WFPD-SH-13	DESIGN BASIS	NO		
WFPD-HSS-209	DESIGN BASIS	NO		
WFPD-HSS-210	DESIGN BASIS	NO		
WFPD-HSS-211	DESIGN BASIS	YES	(same calc as HSS-212 & HSS-212A)	
WFPD-HSS-212	DESIGN BASIS	YES	Con Reqd for piston setting	Walkdown required
WFPD-HSS-212A	DESIGN BASIS	YES	Con Reqd for piston setting	Walkdown required

Note: The loads include the effects of global thermal stratification and postulated locked monoballs.

6.4 WATER HAMMER DISCUSSION

A study was performed to investigate magnitude of loads to cause plastic deformation by first determining the yield stress of the piping under consideration. The yield stress of the piping material A-106 Grade B is 35 ksi per ANSI B31.1 1967. Plastic deformation occurs when this threshold value of stress is exceeded. The corresponding moment for a straight run of 16 inch OD, 0.843 wall thickness pipe is the yield stress multiplied by the section modulus (35000 psi times 170.6 inches cubed which equals approximately 6 million in-lbs). The short radius elbows are associated with a stress intensification factor (stress riser). This factor is based on the elbow geometry and is equal to 2.36 (dimensionless). This reduces the corresponding plastic moments from 6 million in-lbs to 2.5 million in-lbs. Water hammer is the only event that could be identified which could generate loadings of this magnitude.

6.4.1 STEAM GENERATOR WATER HAMMER

The Lawrence Livermore National Laboratory Report [Ref. 9.13] was reviewed to determine the magnitude of loads which could be expected for a steam generator bubble collapse water hammer event. A detailed finite element analysis program (NUPIPE-SW) [Ref. 9.45] was used to determine the movement direction of the feedwater line during a water hammer event. This information leads to the conclusion that a steam generator water hammer could plastically deform the piping into the as-found shape in the beginning of 7R.

6.4.1.1 LAWRENCE LIVERMORE NATIONAL LABORATORY REPORT - STEAM GENERATOR WATER HAMMER

The Lawrence Livermore National Laboratory (LLNL) Report [Ref. 9.13] documents the results of a generic investigation for the effect of hydraulic shock or water hammer on feedwater piping of pressurized water reactors. The most severe water hammer event studied by LLNL occurred at Indian Point Unit 2 Nuclear Power Station where the water hammer caused local deformation of the feedwater pipe near the steam generator, and failure of the pipe at the containment wall. Evidence indicated that the water hammer was caused by the formation and subsequent sudden collapse of a steam bubble in the feedwater line near its inlet to the steam generator. The loads generated by similar steam generator steam bubble collapse events were postulated to be in excess of 100,000 lbs by LLNL.

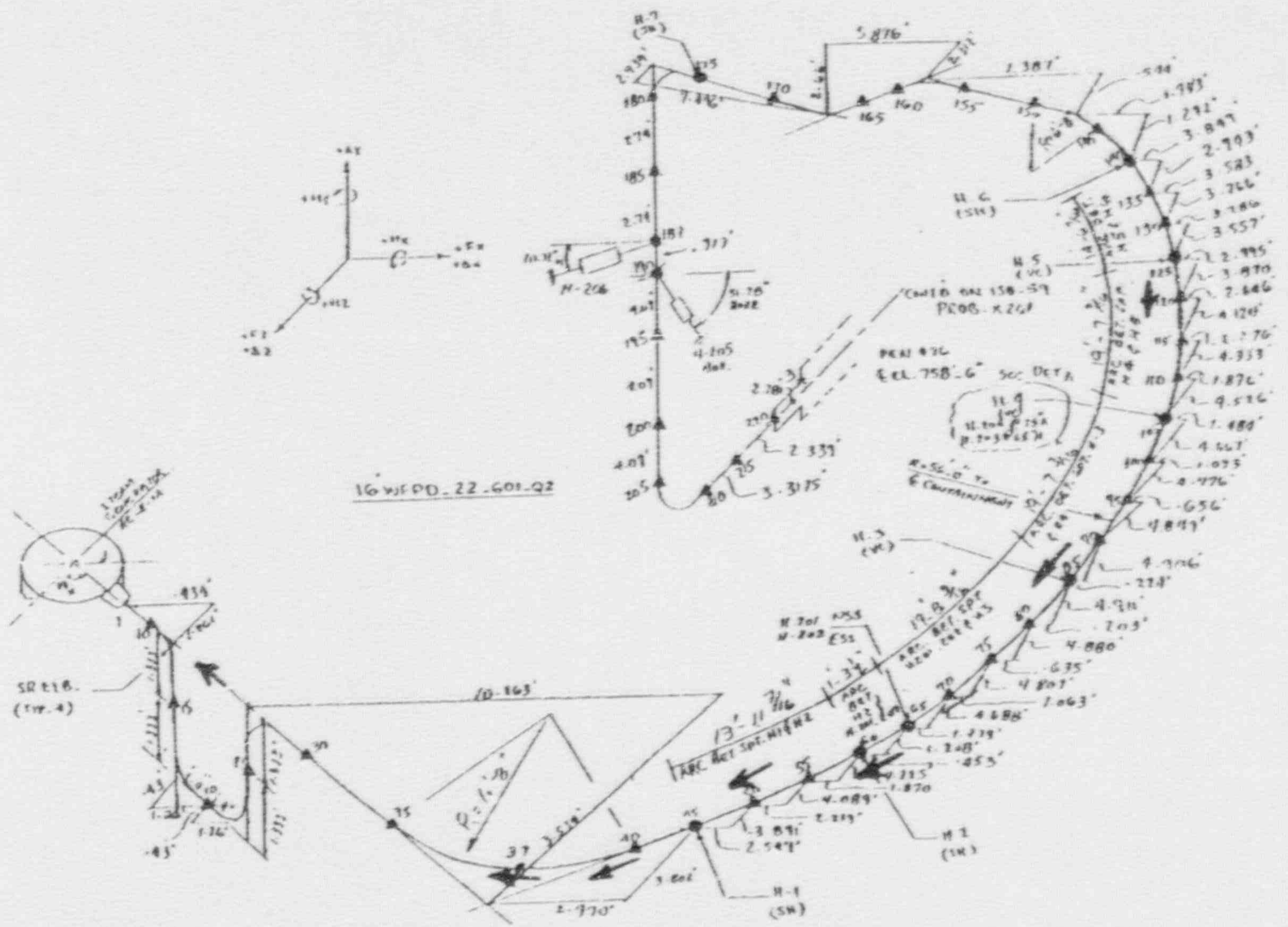
6.4.1.2 STATIC TIME HISTORY ANALYSIS

Three NUPIPE-SW static analyses were performed to determine the direction of displacement of loop A and C feedwater piping. Two analyses were performed on loop A and one on loop C. The analyses of loop A considered the monoballs locked and unlocked.

Loop A considered two models in order to reflect the results of Section 6.1 (postulated locked monoballs). It is considered possible to free the monoballs with large water hammer loads. A ten kip load was statically applied at selected points along the piping (see Figures 6.4.1.2-1 and 6.4.1.2-2 for loops A and C respectively). The loading was applied in the direction of the steam generator. This is consistent with a water hammer event originating in the steam generator. The results of the ten kip load case can be easily increased to obtain results which correspond to the magnitude of loads in the LLNL Report discussed in Section 6.4.1.1. Loop A analyses indicate that the resulting displacements plotted by NUDRAW-SW are both up and in towards the reactor for monoballs restrained or unrestrained (see Figures 6.4.1.2-3 and 6.4.1.2-4 for unrestrained monoballs and 6.4.1.2-5 and 6.4.1.2-6 for restrained monoballs).

The loop C displacement profile (Figures 6.4.1.2-7 and 6.4.1.2-8) also show the loop C piping displacement up and in towards the reactor. The maximum calculated stress (including stress intensification factors) for the 10 kip load on loop A was 3532 psi for unrestrained monoball case and 3525 psi for the restrained case. The stress on loop C was 6581 psi. It is obvious from these stress values that a 100 kip or greater load could result in stress values which would exceed our yield stress value of 35000 psi. Therefore it

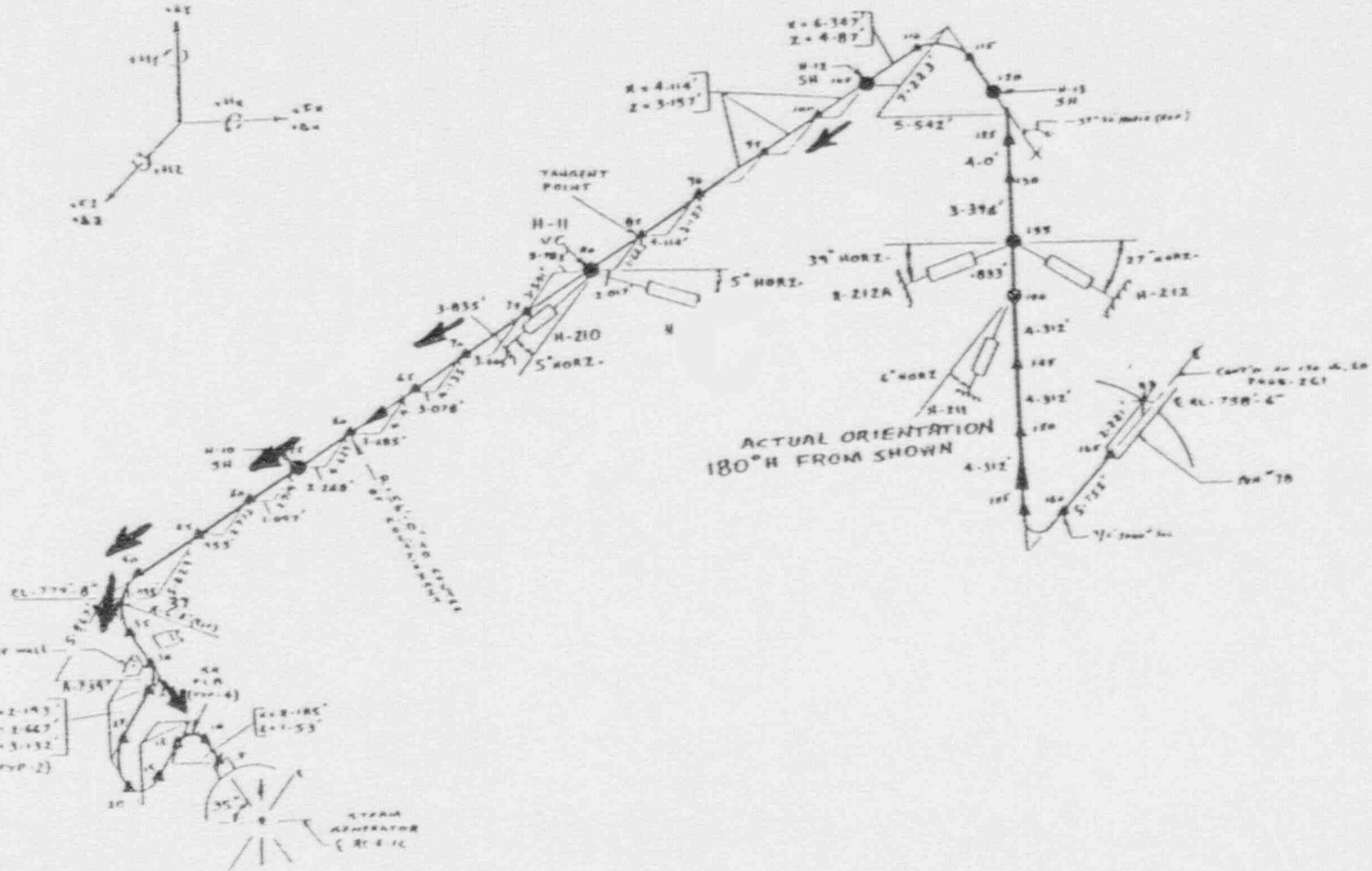
LOCATIONS OF STATIC WATER HAMMER INPUT LOADS - LOOP A



← - Indicates input direction and location of the static 10 kip water hammer load.

FIGURE 6.4.1.2-1

LOCATIONS OF STATIC WATER HAMMER INPUT LOADS - LOOP C



← - Indicates input direction and location of the static 10 kip water hammer load.

FIGURE 6.4.1.2-2

HORIZONTAL DISPLACEMENT RESULTS UNRESTRAINED MONOBALLS - LOOP A

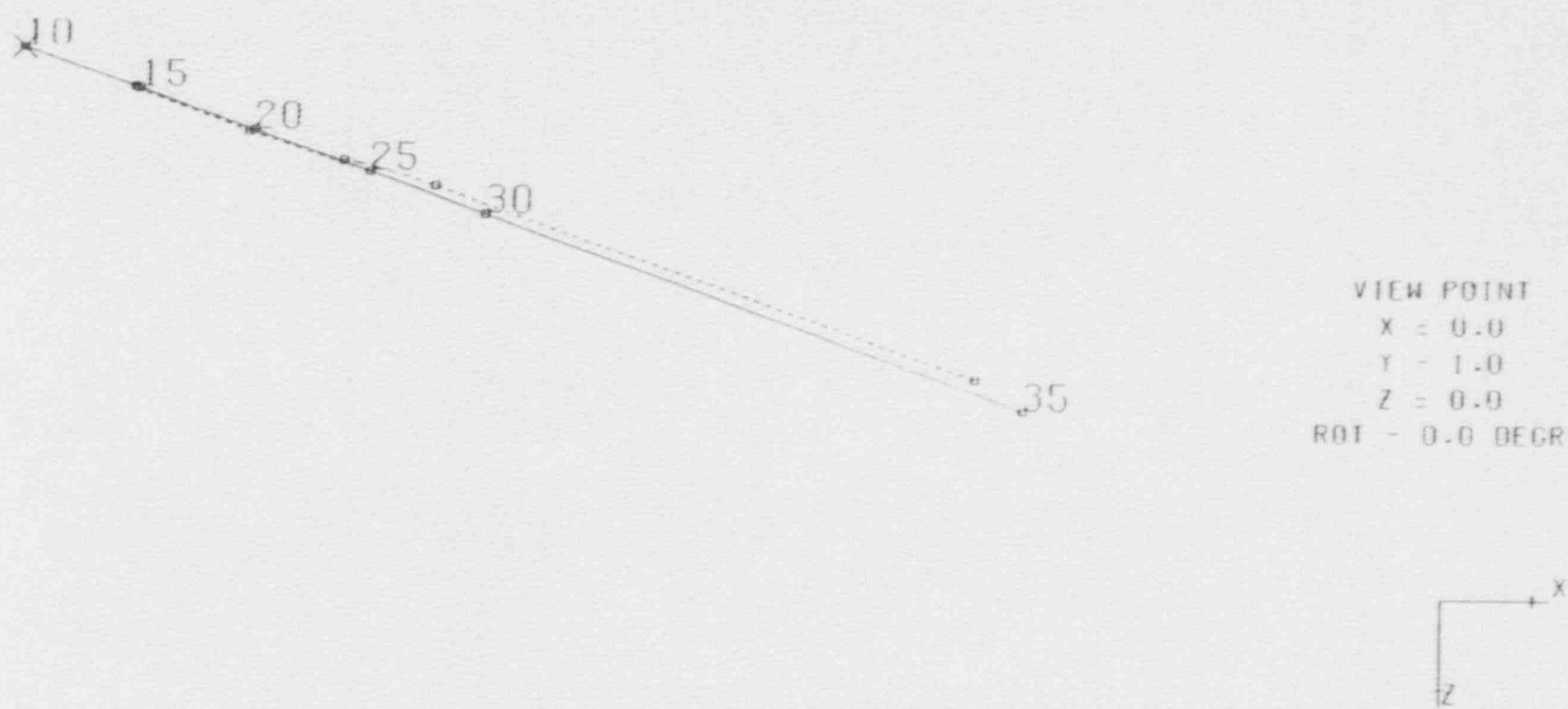


FIGURE 6.4.1.2-3

VERTICAL DISPLACEMENT RESULTS UNRESTRAINED MONOBALLS - LOOP A

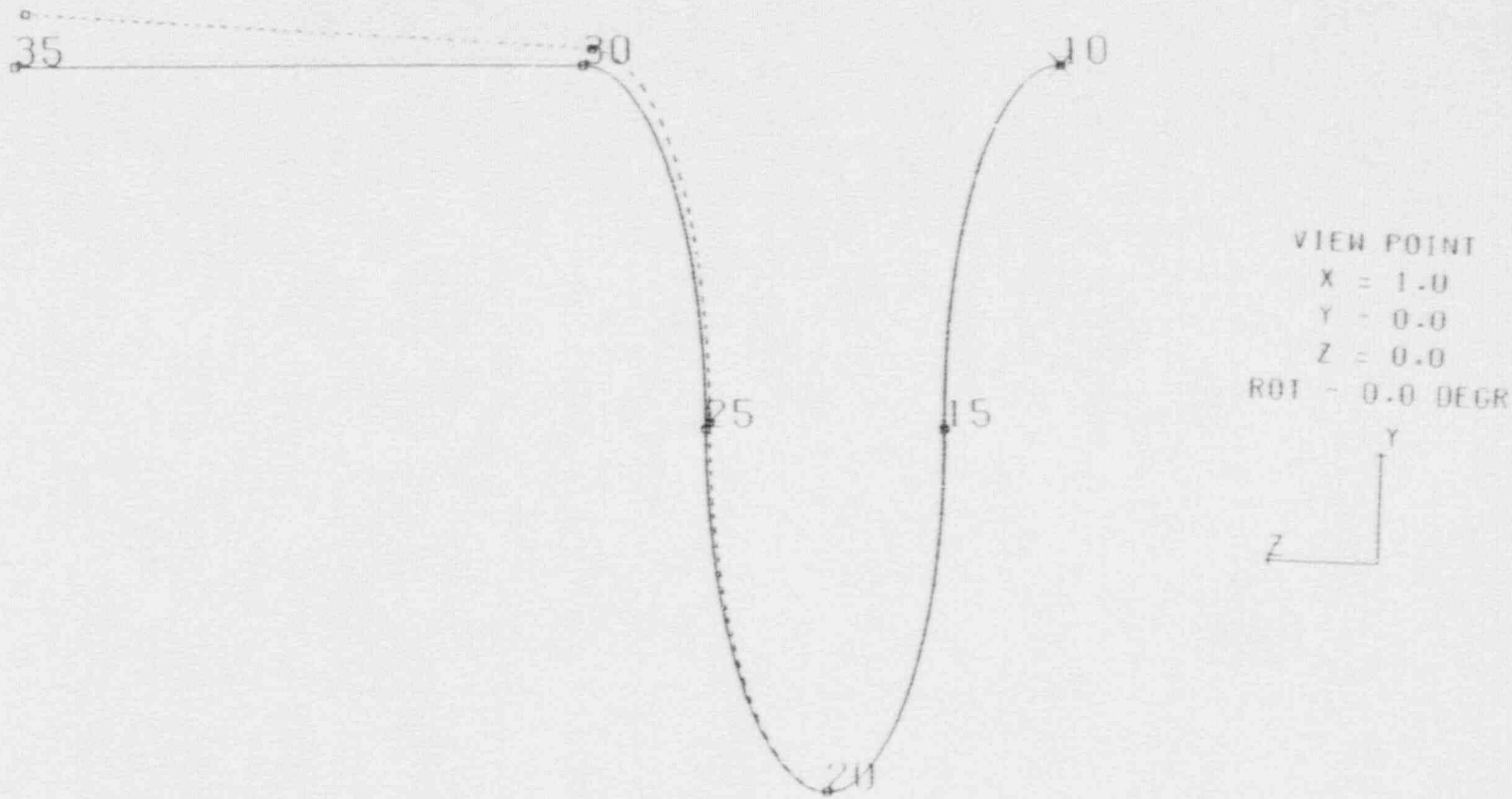


FIGURE 6.4.1.2-4

HORIZONTAL DISPLACEMENT RESULTS RESTRAINED MONOBALLS - LOOP A

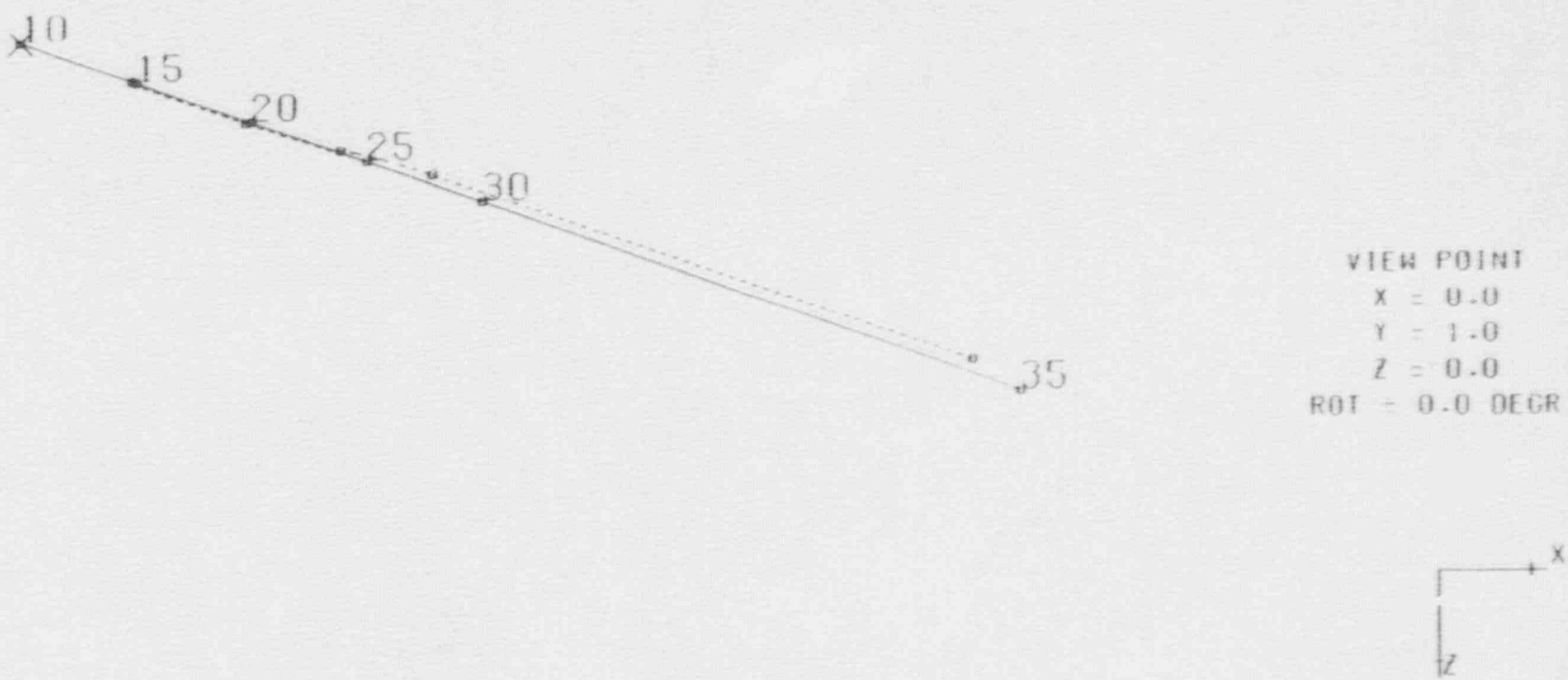


FIGURE 6.4.1.2-5

VERTICAL DISPLACEMENT RESULTS RESTRAINED MONOBALLS - LOOP A

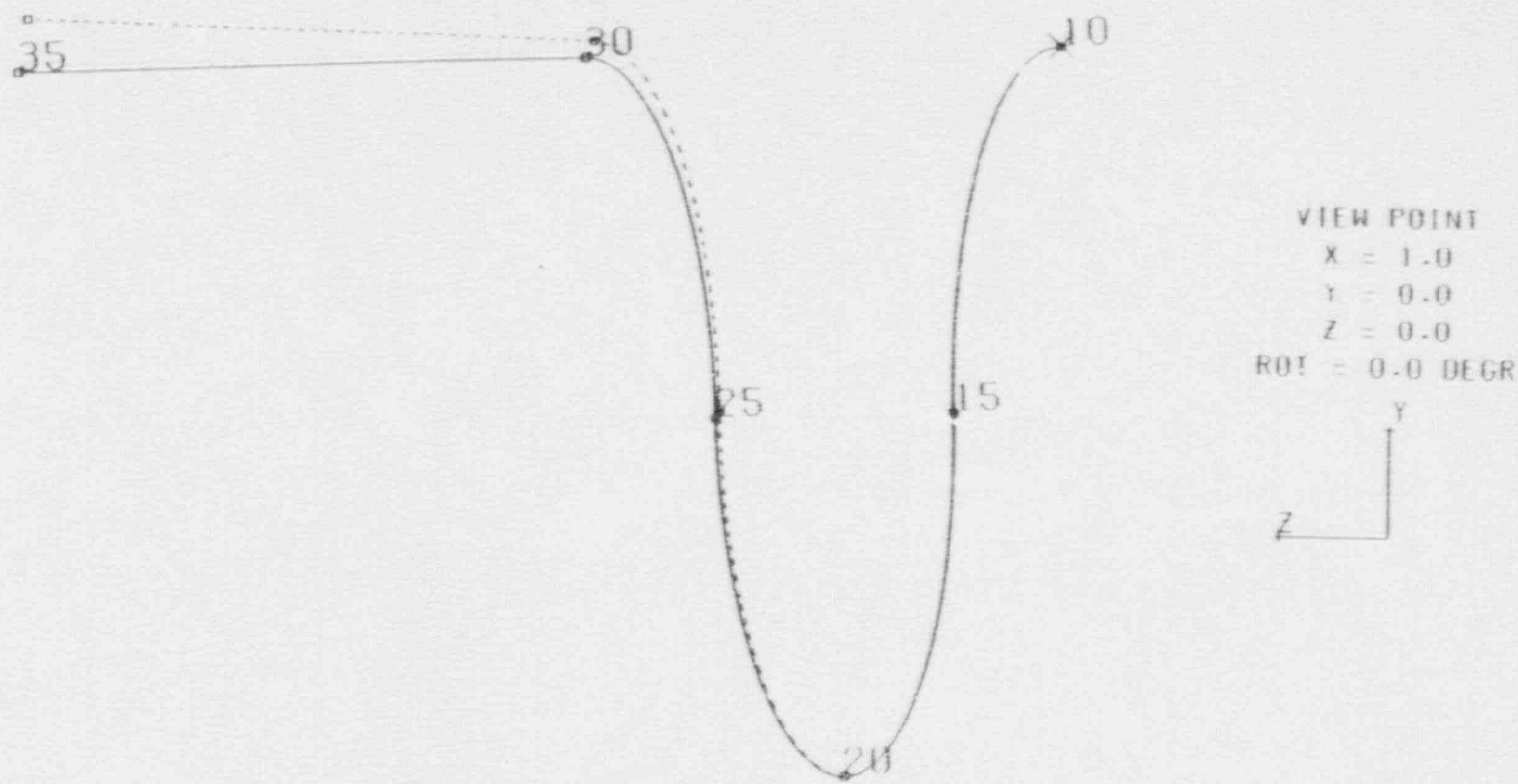


FIGURE 6.4.1.2-6

HORIZONTAL DISPLACEMENT RESULTS UNRESTRAINED MONOBALLS - LOOP C

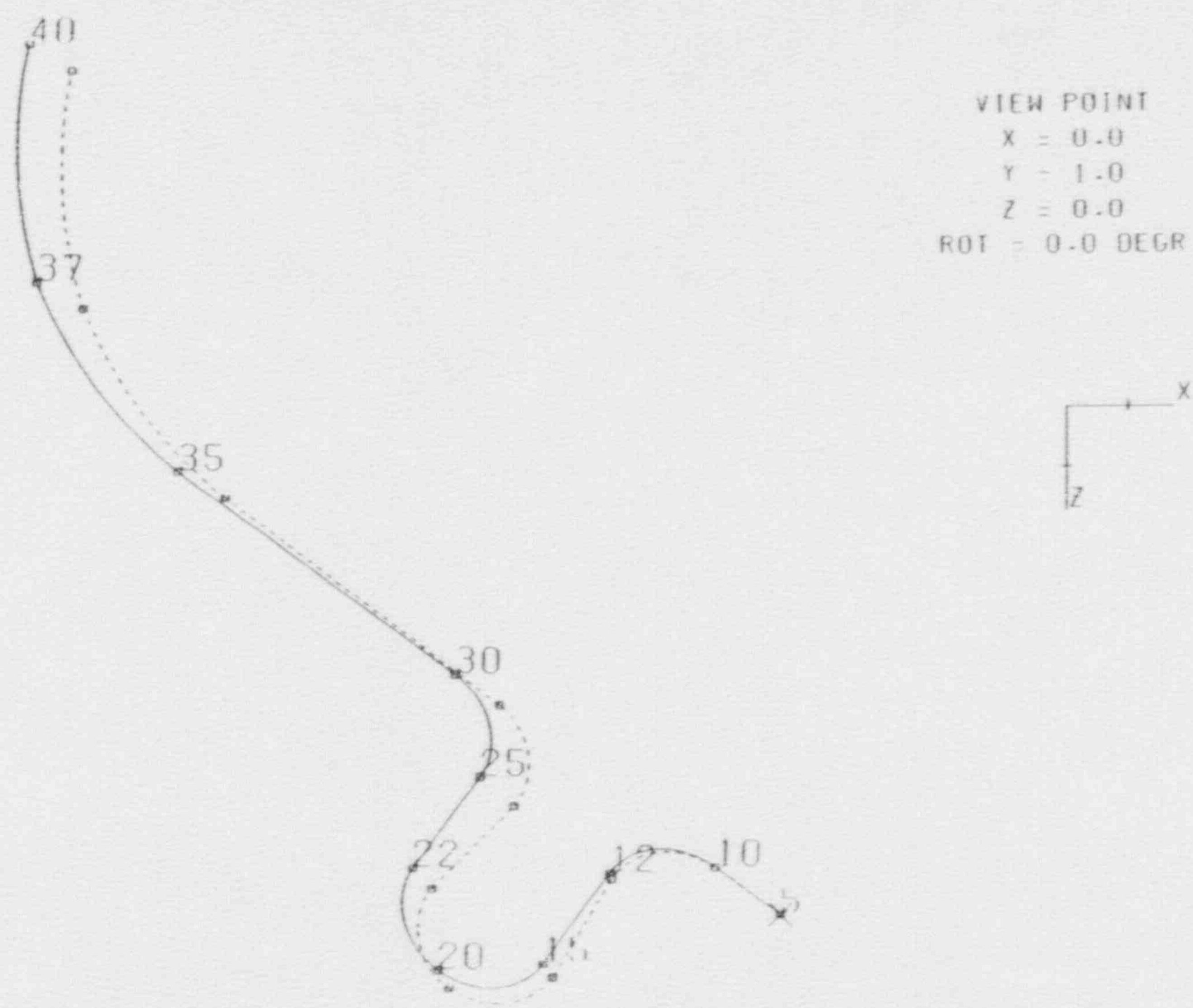


FIGURE 6.4.1.2-7

VERTICAL DISPLACEMENT RESULTS UNRESTRAINED MONOBALLS - LOOP C

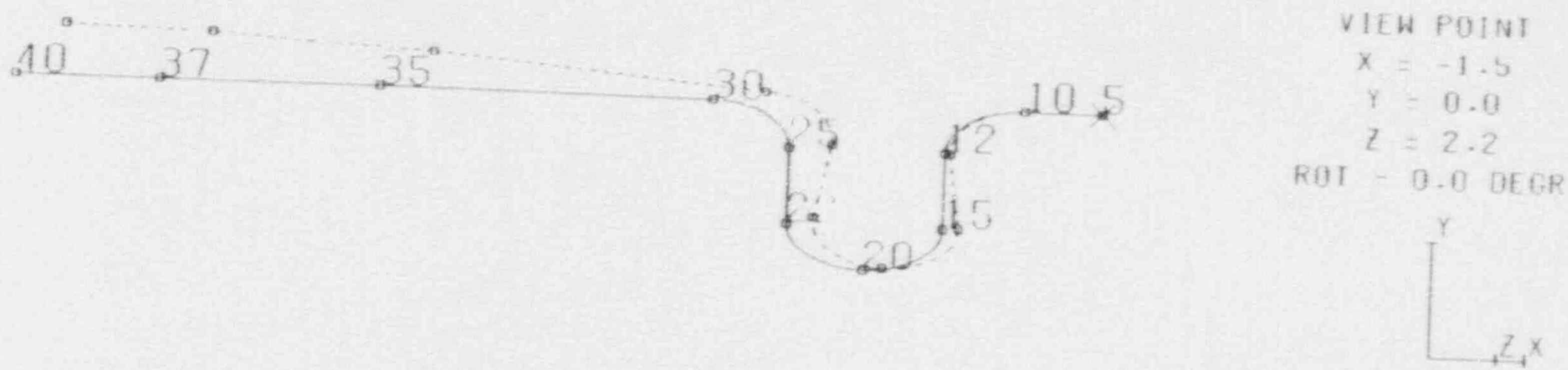


FIGURE 6.4.1.2-8

is concluded that a steam generator bubble collapse event could generate loads of a significant magnitude to plastically deform the piping into the irregular deformation pattern observed at the beginning of 7R.

6.4.2 FEEDWATER REGULATING VALVE FLUID TRANSIENT EVENTS

The main feedwater regulating valves (FRVs) at Beaver Valley Power Station-Unit 1 have been particularly prone to cavitation and resonant vibration problems. This current problem by itself can not generate loadings of 50 kips (See Section 5.3.2). Fifty kips was identified in Section 6.4.1.1 as the load which could begin to plastically deform the loop C piping. Based on review of the snubber design (1 1/2 inch and 2 1/2 inch bore) [Ref. 9.48] if significant loads (assume 15 kips is significant) were developed by this transient event which occurs only during specific power levels, inside containment pipe supports would have been damaged. Since the piping is much more durable than the pipe supports (the pipe can withstand almost 50 kips before yielding) and no pipe supports have been damaged, the current cavitation/resonant vibration problem by itself could not plastically deform the piping inside containment. This is also supported by the recorded data of Reference 9.41 where only local vibration and acceleration of the valve were reported. Additionally damage due to this type of water hammer would have been observed outside containment, consistent with these events in the past (See Section 5.3.2.1).

6.5 LOCAL THERMAL STRATIFICATION

Local thermal stratification in the vicinity of the feedwater nozzle was studied by Westinghouse during their investigation of NRCB 79-13 "Cracking in PWR Feedwater Lines" [Ref. 9.32]. Results from the instrumentation program described in Section 4.5 identified rapid temperature cycling between 557° F (steam generator hot stand-by temperature) and 80° F (the temperature of the fluid drawn from the condenser hotwell during start up). The following discussion examines the recorded plant data and correlates it to the cracking discovered at the beginning of 7R (see Figure 6.5-1 for recorded plant data). Note these data have been modified per the direction of Reference 9.41.

LOCAL STRATIFICATION PROFILE AT THE LOOP A STEAM GENERATOR NOZZLE

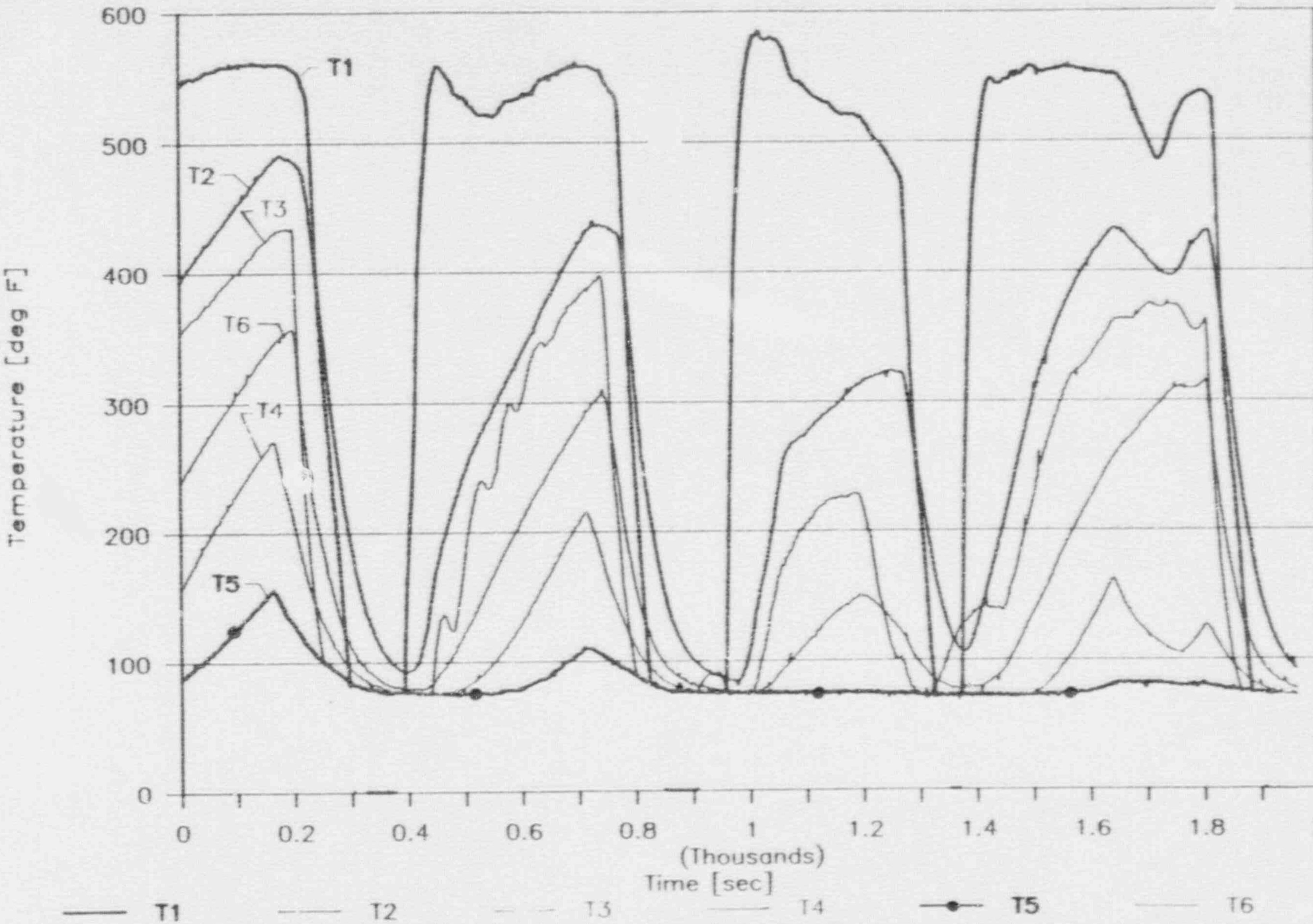


FIGURE 6.5-1

Spurious temperature readings of less than 80° F have been deleted.

6.5.1 CORRELATION TO 7R PLANT DATA

Local thermal stratification was only considered to be a possible contributor to the cracking discovered on the loop A steam generator nozzle taper transition. No possible mechanical link could be identified between the local stratification and the irregular pipe deformation pattern. Since the nozzle cracking was identified as fatigue cracking by metallurgical examination [Ref. 9.49], the data recorded during the post 7R plant restart were reduced into meaningful fatigue data. The reduction of these data is described in the following section of this report.

6.5.1.1 CYCLE COUNTING

The plant data recorded during the post 7R restart of the Beaver Valley Power Station-Unit 1 were reduced. The thermocouple data were graphed for all twelve thermocouples (see Section 4.5 for instrumentation details). The number of cycles, magnitude and mode number of operation were recorded. A data sort was performed and the result of the sort is shown in Table 6.5.1.1-1. This table indicates that thermocouple number 1 (the thermocouple on top of the pipe, almost on top of the taper transition) experiences the most severe thermal cycling. This is confirmed by metallurgical examination [Ref. 9.49] which determined that the largest cracks occurred at the top inside surface of the pipe and were due to corrosion assisted fatigue cracking.

6.5.1.2 CORRELATION TO OPERATION WHEN SIGNIFICANT CYCLING OCCURRED

The data were further reduced by intensity, mode, and plant event for thermocouple number 1. The results of this review are summarized in Table 6.5.1.2-1 for the 7R recorded data. Significant cycles were observed to be present in Modes 1, 2 and 3 (reactor at 29% power to hot standby) during normal heatup and post reactor trip/AFW injection heatup. Significant cycles were not observed during the manual cooldowns on January 19, 1990 and October 6, 1990. More specific correlation to

TABLE 6.5.1.1-1

SUMMARY OF T/C RANGE CYCLES FOR T/Cs 1 THROUGH 6

T/C No.	NUMBER OF TEMPERATURE CYCLES FOR TEMPERATURE RANGE (F)					
	477	400	300	200	100	50
1	75	22	18	39	100	86
2	7	29	53	107	79	64
3	10	23	66	90	128	46
4	13	22	34	53	59	35
5	4	14	15	31	19	14
6	13	35	68	117	111	279

Note:
1) 477 F transients include all transients greater than or equal to 400 F.
2) 400 F transients include all transients greater than or equal to 300 F but less than 400 F.
3) 300 F transients include all transients greater than or equal to 200 F but less than 300 F.
4) 200 F transients include all transients greater than or equal to 100 F but less than 200 F.
5) 100 F transients include all transients greater than or equal to 50 F but less than 100 F.
6) 50 F transients include all transients greater than or equal to 20 F but less than 50 F.

TABLE 6.5.1.2-1

SUMMARY OF CYCLES BY INTENSITY, MODE, AND PLANT EVENT FOR T/C No. 1

477 F INTENSITY

PLANT EVENT	NUMBER OF CYCLES					
	MODE 1	MODE 2	MODE 3	MODE 4	MODE 5	TOTAL
HEAT UP	19	8	6	0	0	33
REACTOR TRIP	21	19	2	0	0	42

400 F INTENSITY

PLANT EVENT	NUMBER OF CYCLES					
	MODE 1	MODE 2	MODE 3	MODE 4	MODE 5	TOTAL
HEAT UP	8	1	5	0	0	14
REACTOR TRIP	8	0	0	0	0	8

300 F INTENSITY

PLANT EVENT	NUMBER OF CYCLES					
	MODE 1	MODE 2	MODE 3	MODE 4	MODE 5	TOTAL
HEAT UP	8	1	5	3	0	17
REACTOR TRIP	1	0	0	0	0	1

TABLE 6.5.1.2-1 (cont.)

SUMMARY OF CYCLES BY INTENSITY, MODE, AND PLANT EVENT FOR T/C No. 1

200 F INTENSITY

PLANT EVENT	NUMBER OF CYCLES					
	MODE 1	MODE 2	MODE 3	MODE 4	MODE 5	TOTAL
HEAT UP	13	1	16	5	0	35
REACTOR TRIP	0	0	0	0	0	0

100 F INTENSITY

PLANT EVENT	NUMBER OF CYCLES					
	MODE 1	MODE 2	MODE 3	MODE 4	MODE 5	TOTAL
HEAT UP	17	17	35	6	1	76
REACTOR TRIP	[illegible]	1	6	0	0	7

50 F INTENSITY

PLANT EVENT	NUMBER OF CYCLES					
	MODE 1	MODE 2	MODE 3	MODE 4	MODE 5	TOTAL
HEAT UP	13	1	13	5	10	42
REACTOR T. _P	0	0	12	0	0	12

TABLE 6.5.1.2-1 (cont.)

SUMMARY OF CYCLES BY INTENSITY, MODE, AND PLANT EVENT FOR T/C No. 1

Mode descriptions are provided below:

Mode	Description
1	Reactor critical at greater than 5% power
2	Reactor critical at less than 5% power
3	Reactor coolant loop at 547 F (Hot Standby)
4	Reactor coolant loop temperature is greater than 200 F but it is less than 350 F (Hot Shutdown)
5	Reactor coolant loop temperature is less than 200 F (Cold Shutdown)
6	Refueling

actual plant operation could not be derived from existing plant operating logs and other recorded plant data (e.g., steam generator level was observed to rise, fall, or remain constant during the most significant local thermal stratification cycles). Plug flow, trickle flow, AFW injection and heatup have been identified by references 9.16, 9.17, 9.18 and 9.19 as potential sources for the significant cycling phenomenon.

6.5.2 THERMAL STRATIFICATION EVENTS

During the evaluation of local stratification it became apparent that the design number of thermal stratification events were much greater than the actual number of events experienced by the plant. Table 6.5.1.2-1 identifies the two plant events (heatup and reactor trip) that were associated with the local thermal stratification phenomenon. The count of plant design events is presented in Section 6.5.2.1 and the number of actual plant events is presented in Section 6.5.2.2.

6.5.2.1 REVIEW OF SYSTEM STANDARD DESIGN CRITERIA 1.3 REVISION 2

Westinghouse Corporation, the nuclear power steam system supplier, has issued several documents concerning plant design transients. The most appropriate design transient document for Beaver Valley Power Station-Unit 1 was determined to be the System Standard Design Criteria (SSDC) 1.3 Revision 2. This SSDC is the closest to the vintage of Beaver Valley Power Station-Unit 1 and is the first design transient document issued with secondary side information. Section 6.5.2 identified the two plant events associated with significant local stratification (heatup and reactor trip). SSDC 1.3 Revision 2, was reviewed to determine the number of design transients associated with those identified events (i.e., the number of heatups and reactor trips). There are 200 postulated heatups and 760 postulated reactor trips that are applicable to the station. See Table 6.5.2.1-1 for a listing of these events based on a 40 year plant life.

TABLE 6.5.2.1-1

SUMMARY OF SSDC 1.3, REVISION 2 TRANSIENTS
(Reactor Trip And Heatup Only)

	REACTOR TRIP	CYCLES		HEATUP	CYLCES
II.1	Loss of load	80	I.1	Heatup	200
II.2	Loss of power	40			
II.3	Partial loss of flow	80			
II.4	Reactor trip	400			
II.5	RCS depressurization	20			
II.7	Control rod drop	80			
II.8	Safety injection	60			
		760 (Total)			

All case II, III, and IV events result in a reactor trip. Case II.6 (loop out of sevice) was excluded because it is not applicable to the Beaver Valley Unit 1 design basis.

Case I - Normal
Case II - Upset
Case III - Emergency
Case IV - Faulted

6.5.2.2 ACTUAL NUMBER OF EVENTS SINCE 1979

The actual number of plant heatups that have taken place between 1979 and 1988 is 20. The actual number of reactor trips that have occurred between 1979 and 1988 is 30. Prorating these values for the remaining 37 years of life since 1979 results in 37/9 x 30 = 123 reactor trips. Additionally the prorated number of events for a forty year plant life would be 102 heatups (37/9 x 20 + 20 heatups before 1979) and 156 (123 + 33 reactor trips before 1979) reactor trips. A heatup event is considered to occur if significant time was spent in Mode 3. It is noted that the actual number of expected cycles is much less than the postulated design events (see Table 6.5.2.1-1).

6.5.3 ESTIMATE OF CYCLES (AND CALENDAR TIME) TO INDUCE CRACKING

The estimate of cycles to induce cracking was developed by the following analytical steps:

The one dimensional heat transfer program HTLOAD [Ref 9.60] was utilized to generate a family of outside wall temperature versus time profiles for an up transient and a down transient (see Figures 6.5.3-1 and 6.5.3-2). These profiles are conservative because the actual profile is probably a ramp. The up transient was input as a step from 80° F to 557° F. The down transient was also input as a step with a temperature range from 557° F to 80° F. Velocity and the corresponding coefficient of heat transfer were varied based on a constant but arbitrary flow rate of 1000 gpm and changing the flowing portion of the pipe (hydraulic radius). The flow rate of 1000 gpm was selected because it is approximately 10% of the design flow rate for the line and would therefore allow thermal stratification to occur. The full intensity (477° F) up transients and down transients were reviewed to determine the representative up transient and down transient. A best fit approach was then used to select the most appropriate up and down transient profile from the HTLOAD results (i.e., HTLOAD outside wall temperatures). Lesser transients considered only a fraction of the full range profile results (i.e., 400° F intensity ranges consider 84% (400/477) of the full range case). Westinghouse analysis results correlate

UP TRANSIENT - STEP FUNCTION

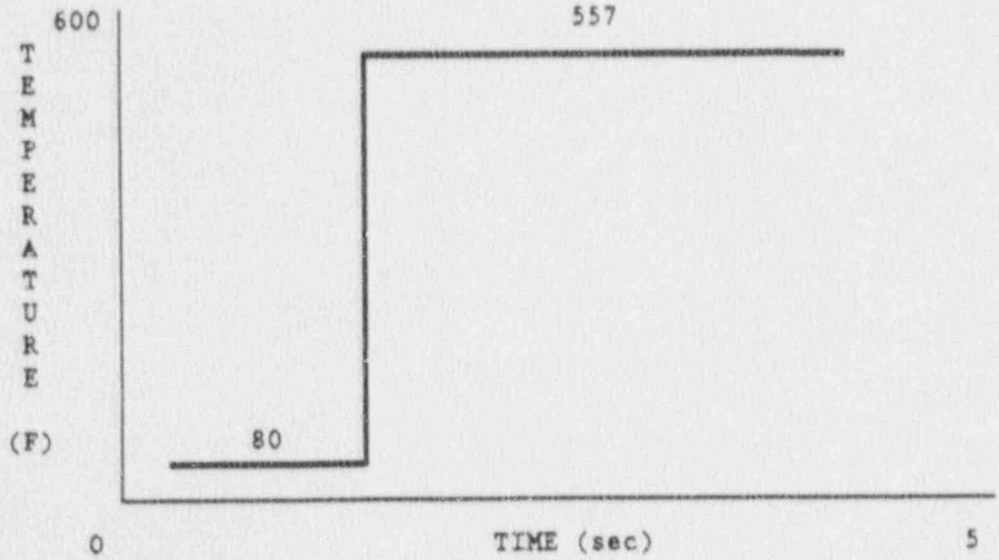


Figure 6.5.3-1

DOWN TRANSIENT - STEP FUNCTION

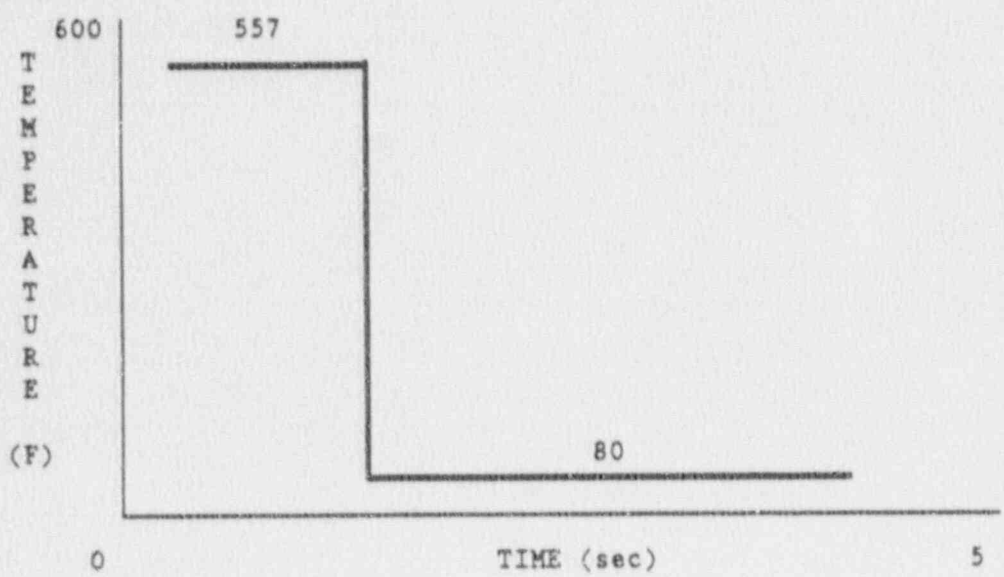


Figure 6.5.3-2

well with the best fit curves selected. The maximum coefficient of heat transfer selected by Westinghouse at the fluid interface was 2000 Btu/hr-ft^2-°F [Ref. 9.17]. This analysis selected 2028 Btu/hr-ft^2-°F.

An analysis was then performed to determine the calculated cumulative usage factor (CUF) for the two plant events identified. Subparagraph NB-3650 from ASME Section III - 1989 was used to provide guidance for the analytical methods utilized. The up transient peak stress was determined to be 101,000 psi, while the down transient peak stress was determined to be -74,000 psi for the full potential transients (i.e., 80° F to 557° F and 557° F to 80° F respectively). Stratification of the steam generator nozzle also generates a global bending moment range. This range cycles along with the local thermal effects above and this peak stress range was calculated to 5000 psi. The total peak stress range is approximately 180,000 psi.

The CUF was determined to be 0.0596 for one plant heatup and 0.0623 for one reactor trip. These values are based solely on the 1989 post 7R restart data. When these values are extrapolated they indicate that approximately 16 plant events (i.e. plant events are defined here as heatups or reactor trips) can occur before cracking is predicted (.0623 x 16 = .9968). When the cumulative usage factor exceeds 1.0, cracking is considered to have been initiated in accordance with design basis criteria. Fourteen plant events have occurred since the taper transitions (elbow) on loops B and C adjacent to the steam generator were replaced. The loop B and C elbows were last replaced in 1988 while the loop A elbow was replaced in 1989. These 14 events occurred over 2 1/2 years. The plant has also experienced an average of over 5 events per year since 1979 (30 reactor trips + 20 heatups / 9 years). The operating period between 1976 and 1979 has been excluded from the average events per year calculation because this was the unit's first fuel cycle. The 1976 to 1979 time period is not indicative of how the plant is operated today. Since the average number of events is 5.5 , 16/5.5 is approximately 3 years. Therefore the taper transition is considered to be crack free until the summer of 1991. This roughly corresponds to operation between 8R and 9R. Note that cracking was discovered at the taper transition in 1979 and in 1988 after about 50 events. This would equate to a CUF of about 3. This may be a realistic value for crack initiation. The postulation of cracking at a component with a CUF of 1 is consistent with ASME Section III.

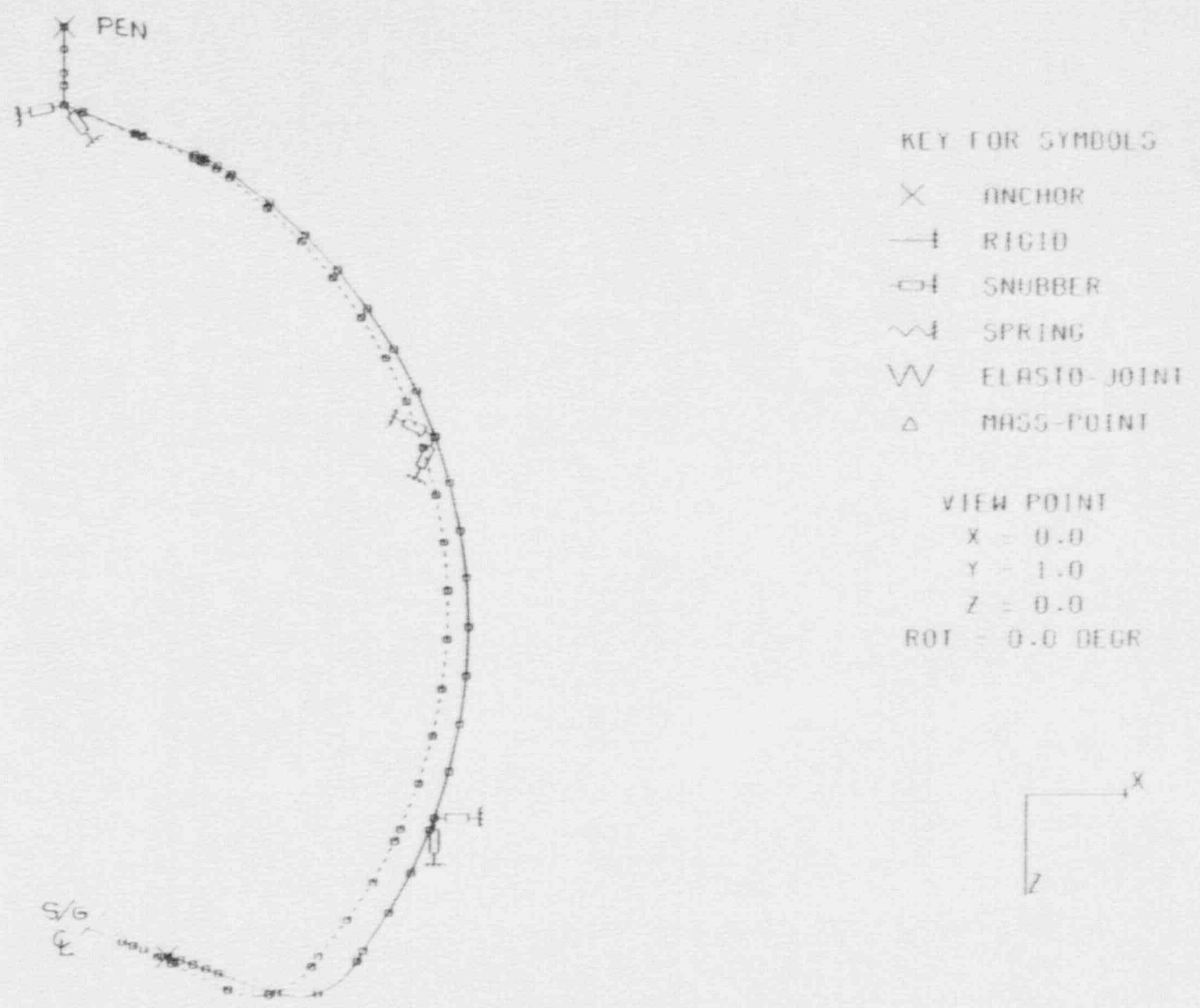
6.5.4 SIGNIFICANCE OF LOCAL THERMAL STRATIFICATION VERSUS PIPE GLOBAL STRATIFICATION TO INDUCE CRACKING

The global bending moments generated by global thermal stratification are considered to be self-limiting for the pipe geometry and support locations at Beaver Valley Power Station-Unit 1 based on extensive analysis. The global stratification bending moments are a function of pipe geometry, support location, and top to bottom differential thermal growth due to top to bottom differential temperature. The stress generated by global thermal stratification was found to be relatively insensitive to support function changes for these specific piping configurations. The thermal stratification Class 2 stress was basically unaffected and always less than 15 ksi intensified for the current pipe support scheme considering the deletion of one or more supports. Since this value is well below the yield stress limit (35 ksi) and the significant global stratification cycles were determined to be infrequent and time independent when compared to local thermal stratification, global thermal stratification was determined not to significantly contribute to the cracking at feedwater nozzle taper transition.

6.6 INSTALLATION

Another possible contributor to the irregular pipe deformation pattern that was considered was a lack of installation control procedures. Cracking was first identified on the taper transition to the steam generator nozzle in 1979 at Beaver Valley Power Station-Unit 1. All three loop elbows adjacent to the steam generator were replaced twice prior to the discovery of the irregular pipe deformation pattern, once in 1979 and once in 1988. Since no installation controlling procedures were provided to construction to recheck rupture restraint gaps and support locations, it is possible that some or all of the misalignment of the feedwater lines occurred during the elbow replacement tasks. A NUPIPE-SW computer analysis was performed to quantify the pipe movement during installation and is discussed in the following section.

PREDICTED HORIZONTAL INSTALLATION DISPLACEMENT PROFILE - LOOP A



1" STATIC DISPL TOWARDS @ STEAM GENERATOR NOZZLE LOOP A

FIGURE 6.6.1-1

PREDICTED HORIZONTAL INSTALLATION DISPLACEMENT PROFILE
MONOBALLS LOCKED LOOP A

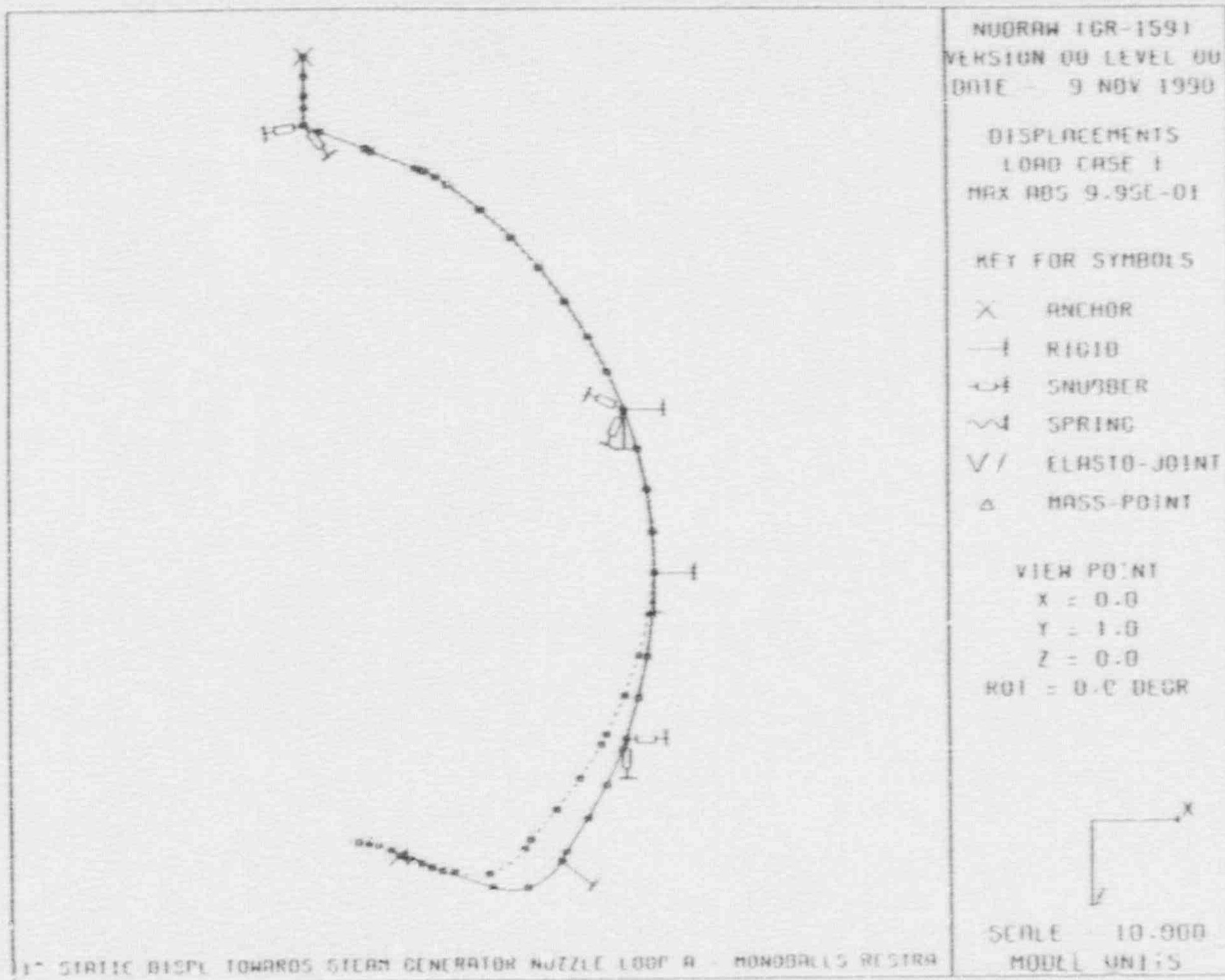
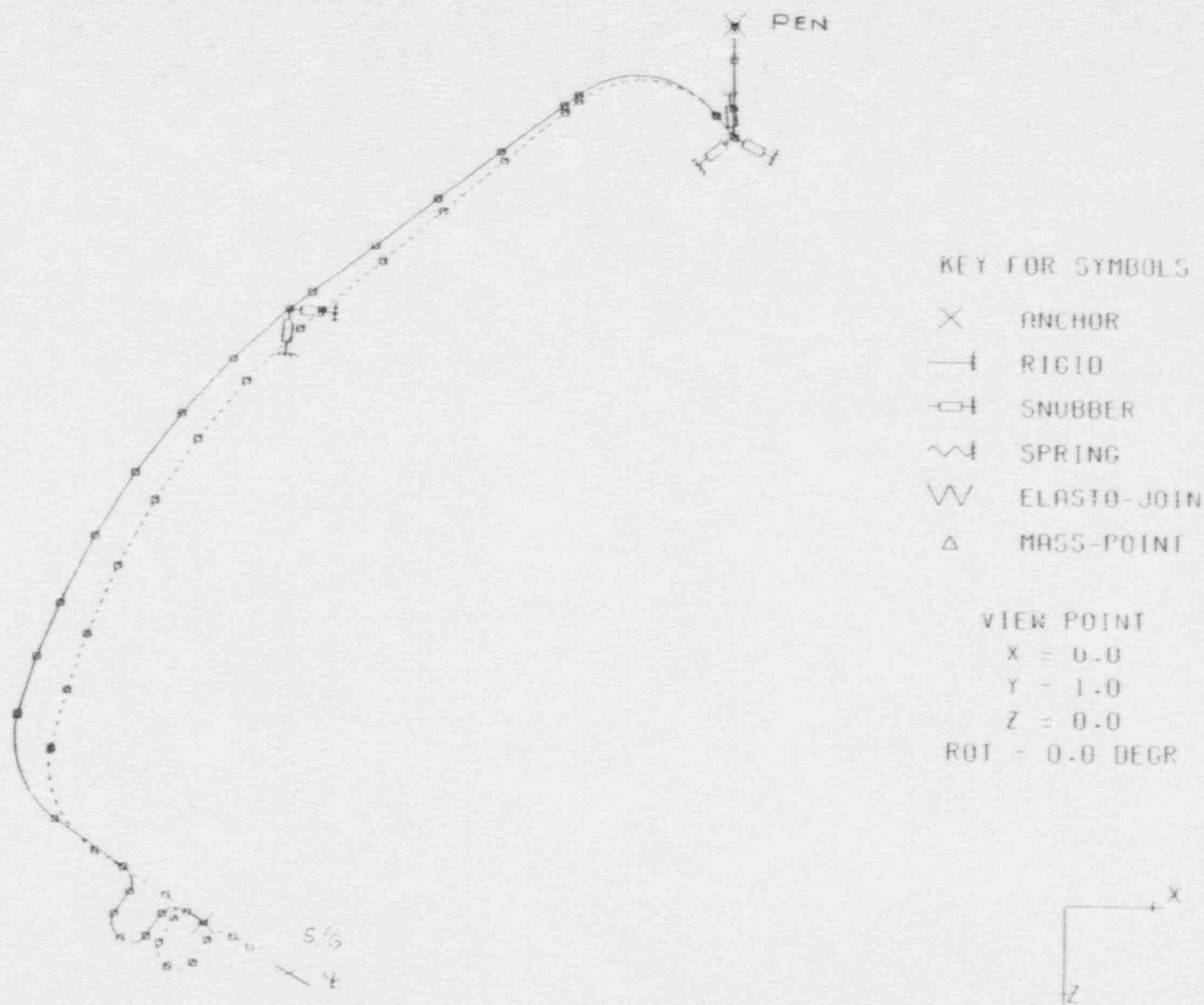


Figure 6.6.1-2

PREDICTED HORIZONTAL INSTALLATION DISPLACEMENT PROFILE - LOOP C



1" STATIC DISPL TOWARDS @ STEAM GENERATOR NOZZLE LOOP C

FIGURE 6.6.1-3

6.6.1 DISPLACEMENT MODEL

Loop A and C models were developed in order to analyze the effects of reducing the steam generator nozzle length by one inch. The one inch dimension was arbitrary, but was also considered to be within the reasonable bounds of nozzle length lost due to weld preparation/shrinkage. A displacement of one inch in the direction of the steam generator nozzle was input in both loops A and C. See Figure 6.6.1-1 for loop A monoballs free, Figure 6.6.1-2 for loop A monoballs locked up and Figure 6.6.1-3 for loop C (monoballs unlocked) for the horizontal displacement results which were plotted by NUDRAW-SW [Ref. 9.51]. A summary of the correlation with the as-found pipe position is provided in Section 6.6.2.

6.6.2 CORRELATION WITH AS-FOUND DISPLACEMENT POSITION

The as-found position of both loops A and C was up and in towards the reactor on the annulus portion of piping in the vicinity of the steam generator. The figures in Section 6.6.1 show that both loops A and C are drawn towards the reactor when the steam generator nozzle length is reduced. No change in elevation is identified by the figures for the input horizontal displacement. However, if the weld preparation on the elbow under the replaced elbow was cut long, the pipe would shift upward.

7.0 CONCLUSIONS

The root cause for the main feedwater line irregular deformation pattern and taper transition cracking have been identified and are discussed in this section of the report. In addition to root cause determination for the two [illegible]ing problems identified above, the potential for global thermal stratification and for significant future water hammer are identified and are also presented here. Design modifications are required to prevent reoccurrences of the irregular deformation pattern and the steam generator nozzle taper transition cracking.

7.1 PIPE IRREGULAR ALIGNMENT

All of the potential root causes were evaluated and are categorized as factors and nonfactors. They are both presented below:

7.1.1 ROOT CAUSE FACTORS

The root cause of the irregular deformation pattern has been determined to be most likely the result of pipe misalignment due to the 1979 and 1988 elbow replacements. In addition to the effects from the elbow replacements some of the irregular pipe deformation pattern on loop A could be attributed to the 1981 water hammer event. The effects of the two types of events are cumulative. Each type of event is discussed below:

7.1.1.1 UNCORRECTED ALIGNMENT FROM THE 1981 WATER HAMMER EVENT

In 1981 the linkage on the loop A main feedwater regulating valve (FRV) failed. This failure allowed the plug to close rapidly and caused a water hammer event that failed two pipe supports inside containment and small branch lines of the main feedwater system. Subsequent to this event on 05/06/81, EM No. 60322 was issued identifying rupture restraint shim stacks on loop A that were dislodged and which could not be returned to their design locations because of a shift in the clearance around the pipe. This relocation may have been caused by the 1979 elbow replacement or this water hammer event.

The piping was not relocated and a portion of the shim stacks were installed creating a small gap on the upper inboard to the reactor side between the feedwater line and the rupture restraint. Most transient events experienced by Beaver Valley Power Station-Unit 1 per the Licensee Event Report (LER) listing are not of a significant magnitude such that an irregular pipe deformation pattern would be expected to occur.

7.1.1.2 PIPING MISALIGNMENT DUE TO THE 1979 AND 1988 ELBOW REPLACEMENT

The piping which may have been relocated by the water hammer loads was not zero gapped against the rupture restraint on loop A after the last significant water hammer event had been recorded in 1981 in the LERs. Only the installation could have relocated the piping from 3/64 inch gap (EM No. 60322) to zero gap after the 1981 FRV linkage failure induced water hammer on loop A. Only piping misalignment due to the 1979 and 1988 elbow replacement could be responsible for the irregular deformation pattern on loop C. The other possible root causes were determined to be nonfactors and are summarized below.

7.1.2 NONFACTORS

Local stratification as the name implies is only a local phenomenon and could not permanently relocate the piping. Global stratification class 2 stress levels with or without monoballs locked were determined to be well below the yield stress limit. Therefore global stratification could not have contributed to the irregular deformation pattern. Since no pipe support damage was reported, steam generator water hammer and feedwater regulating valve resonance/vibration were also eliminated as possible sources of piping irregular deformation pattern (pipe support damage would be expected to occur before pipe yielding could begin).

7.2 STEAM GENERATOR NOZZLE TAPER TRANSITION CRACKING

All of the potential root causes were evaluated and are categorized as either factors or nonfactors. Factors and nonfactors are presented below:

7.2.1 ROOT CAUSE FACTORS

The root cause of the steam generator nozzle taper transition cracking has been determined to be local thermal stratification. Rapid fluctuations of the through wall pipe temperature during Modes 1, 2 and 3 (See Appendix C) are associated with significant fatigue of the feedwater nozzle taper transition. The effects of the rapid through wall temperature changes were quantified and determined to be consistent with the issues identified in NRC IE Bulletin 79-13 [Ref 9.12]. The analytical results indicate that cracking on the steam generator nozzle taper transition could begin to occur after about 1[illegible] events. One event is defined here as one heatup from the refueling mode or one reactor trip (See Appendix C). This corresponds to a time period of concern beginning during the summer of 1991. (see Section 6.5 for the detailed discussion of analysis results).

7.2.2 NONFACTORS

Several different feedwater system transients were identified as possible root causes or contributors to the taper transition cracking. The following list of transients were determined not to significantly contribute to the cyclic fatigue cracking identified by metallurgical examination:

a. Global stratification was eliminated because of the small number of events recorded during the post 7R heatup, the apparent independent nature of the global and local stratification cycling and the relatively low magnitude of stress levels generated at the taper transition (see Section 6.5.4).

b. Main feedwater regulating valve (FRV) instability alone was eliminated because the magnitude of loads generated due to this event is below the elastic limit of the pipe. Although resonance has been identified on the A loop at 66% power [Ref. 9.35], instrumentation has confirmed that large pressure oscillations and the resulting large forcing functions are not being generated into the piping system. For the water hammer event to occur, the resonance must cause a mechanical failure (i.e., linkage) at the valve as was the case in the 1981 event. Water hammer due to the failure of the FRV is a separate issue and has only occurred once on loop A at Beaver Valley Power Station-Unit 1 since the last replacement of the elbow and was, therefore, also eliminated.

c. Steam generator water hammer was eliminated because no evidence of a steam generator water hammer was identified after the replacement of the elbows in 1979.

d. Installation, which was identified as a contributor to the irregular pipe deformation pattern, is a one-time event and, therefore, could not contribute to cyclic fatigue.

7.3 GLOBAL STRATIFICATION

Global thermal stratification of the loop A feedwater line at Beaver Valley Power Station-Unit 1 was identified during the reduction of post 7R heatup data. Based on the collected data, global thermal stratification causes the feedwater line to deflect with a larger magnitude and in the opposite direction of the design basis analysis. This phenomenon occurs on all three feedwater lines at the station. Analysis of all three lines for the global stratification phenomenon indicated that the piping met the ANSI B31.1 1967 design basis equation allowables. Certain pipe supports when considering global thermal stratification and locked monobails, could not meet their original design basis equation requirements but have been shown to meet alternate criteria (see Table 6.3-4). Global stratification could also account for the dislodged shim stacks at restraint FWR-1.

7.4 POTENTIAL FOR FUTURE WATER HAMMER

During the investigation of the irregular pipe deformation pattern it became apparent based on review of LER's and the lack of support damage that although Beaver Valley Power Station-Unit 1 had not recently experienced a water hammer initiated at the steam generator other PWRs of a similar vintage and design had. Summarized below are four items of concern that are directly related to the potential for future steam generator water hammer at Beaver Valley Power Station-Unit 1.

7.4.1 SIMILARITY TO TROJAN NUCLEAR POWER STATION

Trojan Nuclear Power Station is a four loop Westinghouse PWR designed and constructed during the same time period that Beaver Valley Power Station-Unit 1 was designed and constructed. Specific feedwater system similarities between Beaver Valley Power Station-Unit 1 and the Trojan Nuclear Power Station include:

a. Both have J-tubes installed on the feedring.

b. Both initiate auxiliary feedwater (AFW) immediately after a reactor trip.

c. Both have short horizontal lengths between the loop seal and the steam generator nozzle.

Prior to the Trojan steam generator water hammer the two units also provided maximum AFW flow to the steam generators and had slip fit thermal sleeves. For Beaver Valley Power Station Unit-1 the maximum auxiliary feedwater flow to each steam generator is 460 gpm. Trojan has since limited the maximum AFW flow rate, has repaired the thermal sleeve slip fit and has replaced its eroded J-tubes.

Trojan experienced a severe steam generator water hammer event prior to its seventh refueling outage [Ref. 9.36]. During the refueling outage several pipe supports were found to be damaged and the piping was found to be relocated. Subsequent to the discovery an analysis was performed. This analysis estimated that the maximum forces generated by this event was 45 kips. The 45 kip load results from a 22 cubic inch steam void that developed in the feedring. The void in the feedring formed because of erosion in the feedring thermal sleeve slip fit connection in the vicinity of the steam generator nozzle. Beaver Valley Power Station-Unit 1 is susceptible to the same thermal sleeve erosion problems that caused this significant but by no means bounding event.

As observed at BV-1 following the 29% reactor trip on December 26, 1989, the steam generator level dropped to as low as 11% narrow range band. Auxiliary feedwater initiated approximately 1 to 2 minutes following the feedwater isolation (FWI) signal.

7.4.2 THERMAL SLEEVE EROSION

Erosion of the Westinghouse low tolerance slip fit thermal sleeves have been examined. Localized gaps of up to 1/4 inch have been found on operating steam generator feedring slip fit connections. The void of 22 cubic inches postulated at Trojan could easily develop in less than 30 seconds with this magnitude of gap. The void would be generated before the auxiliary feedwater system could supply water to the partially uncovered feedring. Since the integrity of the thermal sleeve slip fit is unknown at Beaver Valley Power Station-Unit 1 (Westinghouse has welded this connection in more recent installations), the potential for a water hammer equally or more severe than the event at Trojan is significant and should be quantified.

7.4.3 J-TUBE EROSION

Another potential concern which is similar to the erosion of the thermal sleeve is erosion of the J-tubes on the top of the feedring. The J-tubes were installed as a design modification to prevent steam from entering the feedring. These tubes have been found to erode at a faster rate than the corrosion allowance originally anticipated and specified by Westinghouse. Several eroded J-tubes (the latest inspection performed during the 7R outage indicates that the worst erosion loss is as great as 50% locally) could result in a significant water hammer. The verification of the erosion to the J-tube lends additional credence to the concern that the thermal sleeve is also eroding. The sleeve and J-tubes are composed of similar material. The integrity of the J-tubes should be verified. The feedring was originally provided with holes in the bottom. These holes were plugged when the J-tubes were installed. The integrity of these plugs should be verified to prevent a severe water hammer.

7.4.4 AUXILIARY FEEDWATER IMPLICATION

The auxiliary feedwater supply is provided by a safety related source (demineralizer water storage tank) which is located in the yard and is protected from freezing by space heaters. The rapid injection of cold auxiliary feedwater will collapse a steam void more rapidly than the injection of auxiliary feedwater at a slower rate. Westinghouse Technical

Bulletin [Ref. 9.58] and NUREG-0291 [Ref. 9.31] recommended this to minimize the effect of collapsing any voids that occur in the feedring. The adoption of a maximum auxiliary feedwater flow rate limit is advised in order to minimize the auxiliary feedwater flow. Reduction of the flow from the existing maximum available flow rate of approximately 460 gpm per steam generator is considered to be a prudent water hammer prevention precaution.

Any consideration of imposing a maximum upper limit on auxiliary feedwater injection to minimize water hammer potential has to consider that minimum auxiliary feedwater flow rates must be provided to satisfy safety/accident analysis.

8.0 RECOMMENDED CORRECTIVE ACTIONS

Recommended corrective actions to prevent reoccurrence of the irregular pipe deformation pattern and the steam generator nozzle taper transition cracking are presented in this section. In addition corrective actions are also provided to prevent future steam generator water hammer to which Beaver Valley Power Station-Unit 1 is susceptible and to address and qualify pipe supports under certain conditions (i.e., global stratification and monoball locked conditions). The corrective actions are categorized as mandatory, strongly recommended and recommended. Mandatory corrective actions are the minimum actions required to meet design basis requirements. Strongly recommended corrective actions are those actions that significantly enhance the reliability of the unit. Recommended actions are those actions which establish baseline information in support of future NRC inquiries and or enhance the reliability of the unit. Mandatory, strongly recommended and recommended corrective actions are presented in Sections 8.1, 8.2 and 8.3 respectively.

8.1 MANDATORY CORRECTIVE ACTIONS

The mandatory corrective actions involve two of the four concerns discussed above. The irregular deformation pattern and the potentially locked monoball supports require correction. There are no mandatory corrective actions required for the future possible water hammer or steam generator nozzle cracking concerns.

8.1.1 IRREGULAR DEFORMATION PATTERN

The mandatory corrective action for the irregular pipe deformation pattern is to realign the piping to its as-designed position. This was accomplished during the unit's 7th refueling outage.

8.1.2 GLOBAL STRATIFICATION AND POTENTIALLY LOCKED MONOBALL SUPPORTS

The mandatory corrective actions for global stratification and potentially locked monoball supports are to:

a. Confirm analysis assumptions through an enhanced instrumentation program (see Section 8.1.2.1).

b. Revise pipe rupture criteria to be consistent with Mechanical Engineering Branch Technical Position 3-1 (MEB 3-1) (see Section 8.1.2.2).

c. Measure the existing elbow wall thickness (see Section 8.1.2.3).

d. Modify or replace the monoball supports R-3, R-4 and R-11 which do not meet plant design basis criteria (see Section 8.1.2.4).

e. Inspect supports to verify input assumptions (see Section 8.1.2.5).

f. Perform an interim evaluation, implement OBE seismic limits and issue a justification for continued operation (JCO) (see Section 8.1.2.6).

g. Revise design basis documentation to include ASME Boiler and Pressure Vessel Code Case N-318 (see Section 8.1.2.7).

These issues are discussed in detail in the following paragraphs.

8.1.2.1 CONFIRM ANALYSIS ASSUMPTION THROUGH INSTRUMENTATION

The loop A and C current design basis analyses which qualify the piping and pipe supports are based on a scale factor (62%) of the potential thermal stratification during auxiliary feedwater injection, post reactor trip at 100% power. The loop B piping is based on 100% of the potential. This is a conservative approach for this loop and provides long term qualification for the piping components independent of results from future data collection activities. The scale factor of 62% is based on reduction of plant data recorded from temporary instrumentation on loop A during one plant restart and one reactor trip. The AFW event occurred at 29% power and these results were then extrapolated to the 100% power case. Since these results are based on only one reactor trip at less than full power on only one of the two loops of concern, the recommendation is made to gather additional baseline data. Instruments should be placed on loop C. In addition to the loop C instrumentation, loop A instrumentation must also be upgraded to obtain the most accurate thermal stratification profile. The additional instrumentation will provide a more detailed thermal stratification profile for analysis if the current 245° F of thermal stratification is exceeded. See Figures 8.1.2.1-1 (loop A) and 8.1.2.1-2 (loop C) for instrumentation locations, types and quantities recommended.

8.1.2.2 REVISE PIPE RUPTURE CRITERIA (MEB 3-1)

Pipe stress analysis equations for all design basis criteria were satisfied except for the pipe rupture criteria. The current Beaver Valley Power Station-Unit 1 design basis pipe rupture criteria is more conservative than the current NRC criteria. Review of the NRC Mechanical Engineering Branch Technical Position 3-1 (MEB 3-1) [Ref. 9.6] of Standard Review Plan 3.6.2, the most current NRC position, indicates that relief from the conservative Beaver Valley Power Station-Unit 1 pipe rupture criteria is available and applicable to Beaver Valley Power Station-Unit 1. Based on the newly identified global stratification condition, it is necessary to adopt the current NRC pipe rupture stress limits in order to show compliance to a long term plant design basis for pipe rupture. Therefore, the latest NRC criteria, MEB 3-1, was adopted for the feedwater lines. It is also recommended to adopt the latest criteria for other systems if reanalysis is performed on them.

8.1.2.3 MEASURE EXISTING ELBOW WALL THICKNESS

In 1981 wall thinning of the feedwater lines was identified. The manufactured wall thickness per catalog data is .843 inches. However, the wall thickness may be as low as .750 inches. The current analyses for the unanalyzed condition consider a wall thickness of .843 inches (for the piping and elbows) for the structural analysis and considers local thinning down to .75 inches. Since the loop seal elbows which are not replaced during the addition of the thermal sleeve are at

PROPOSED INSTRUMENT PLAN LOOP A

$T_1 . T_2$ - EXTING THERMALCOUPLE

L - EXISTING LANARD

T_P - PROPOSED THERMOCOUPLE LOCATION

L_P - PROPOSED LANYARD LOCATION

T_{P1} - LOCATE MID WAY BETWEEN EXISTING THERMOCUPLE T AND 45° SLOP DOWN

T_{P2} - LOCATE MID POINT OF PIPE RUN ON ELEVATION 776'-11"

T_{P3} & L_{P2} - LOCATE MID WAY BETWEEN PENETRATION AND RISER

L_{P1} - LOCATE ADJACENT TO FWR-19

THE EXISTING THERMOCOUPLES AND LANYARD WILL REMAIN IN PLACE FOR FUTURE DATA RECORDING. SEE FIGURE 4.5-1 FOR DETAILED LOCATIONS.

EACH THERMOVOUPLE LOCATION WILL HAVE A MINIMUM OF (3) THERMOCOUPLES LOCATED AT 3, 6 AND 12 O'CLOCK AROUND THE PIPE.

EACH LANYARD LOCATION WILL HAVE (3) LAYNARDS TO MEASURE THE VERTICAL, LATERAL AND AXIAL DEFELECTIONS.

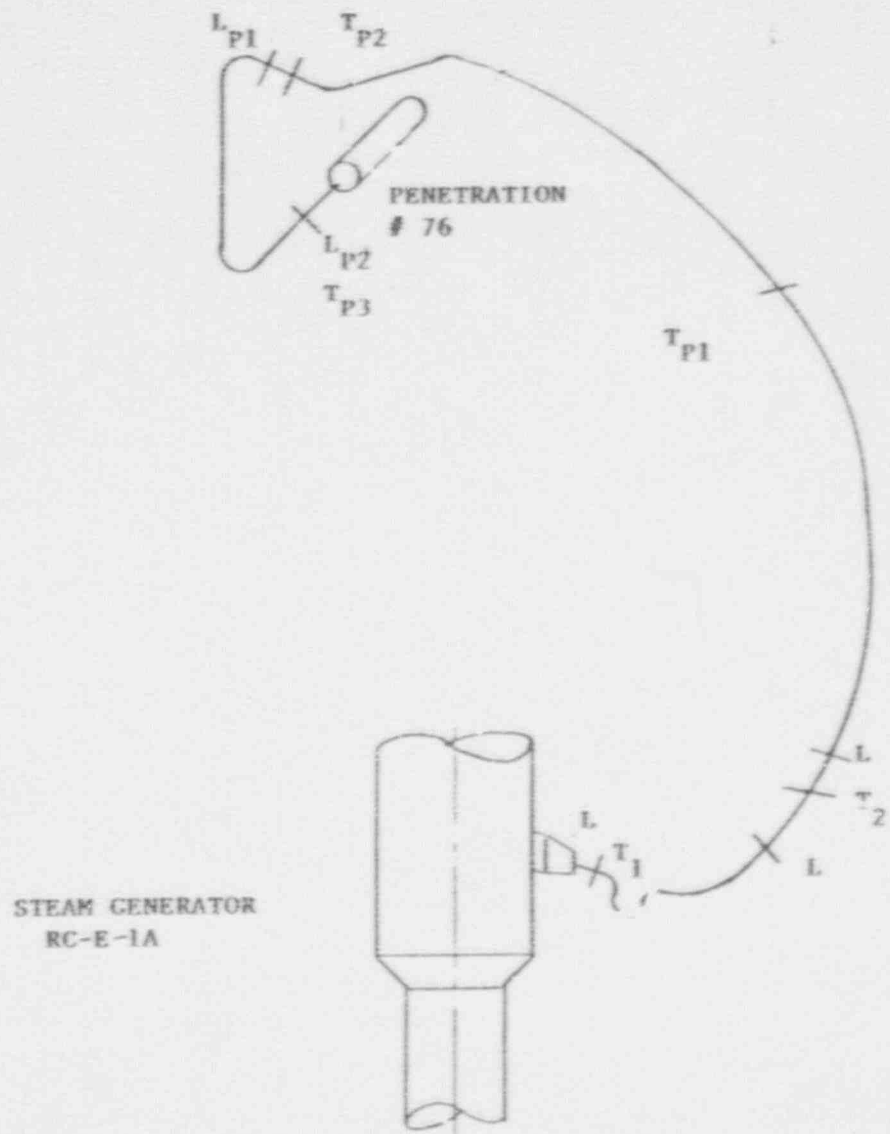


FIGURE 8.1.2.1-1

LOOP A

PROPOSED INSTRUMENT PLAN LOOP C

T_P - PROPOSED THERMOCOUPLE LOCATION

L_P - PROPOSED LAYNARD LOCATION

T_{P1} - LOCATE MID WAY BETWEEN LOOP SEAL AND CRANE WALL

T_{P2} - LOCATE MID WAY BETWEEN L_{P1} AND L_{P2}

T_{P3} LOCATE 6 FEET FROM L_{P2}

T_{P4} & L_{P3} - LOCATE MID WAY BETWEEN PENETRATION AND RISER

L_{P1} LOCATE ADJACENT TO FWR-1

L_{P2} LOCATE ADJACENT TO FWR-13

EACH THERMOCOUPLE LOCATION WILL HAVE A MINIMUM OF (3) THERMOCUPLES LOCATED AT 3, 6 AND 12 O'CLOCK AROUND THE PIPE.

EACH LANYARD LOCATION WILL HAVE (3) LANYARDS TO MEASURE THE VERTICAL, LATERAL AND AXIAL DEFELECTIONS.

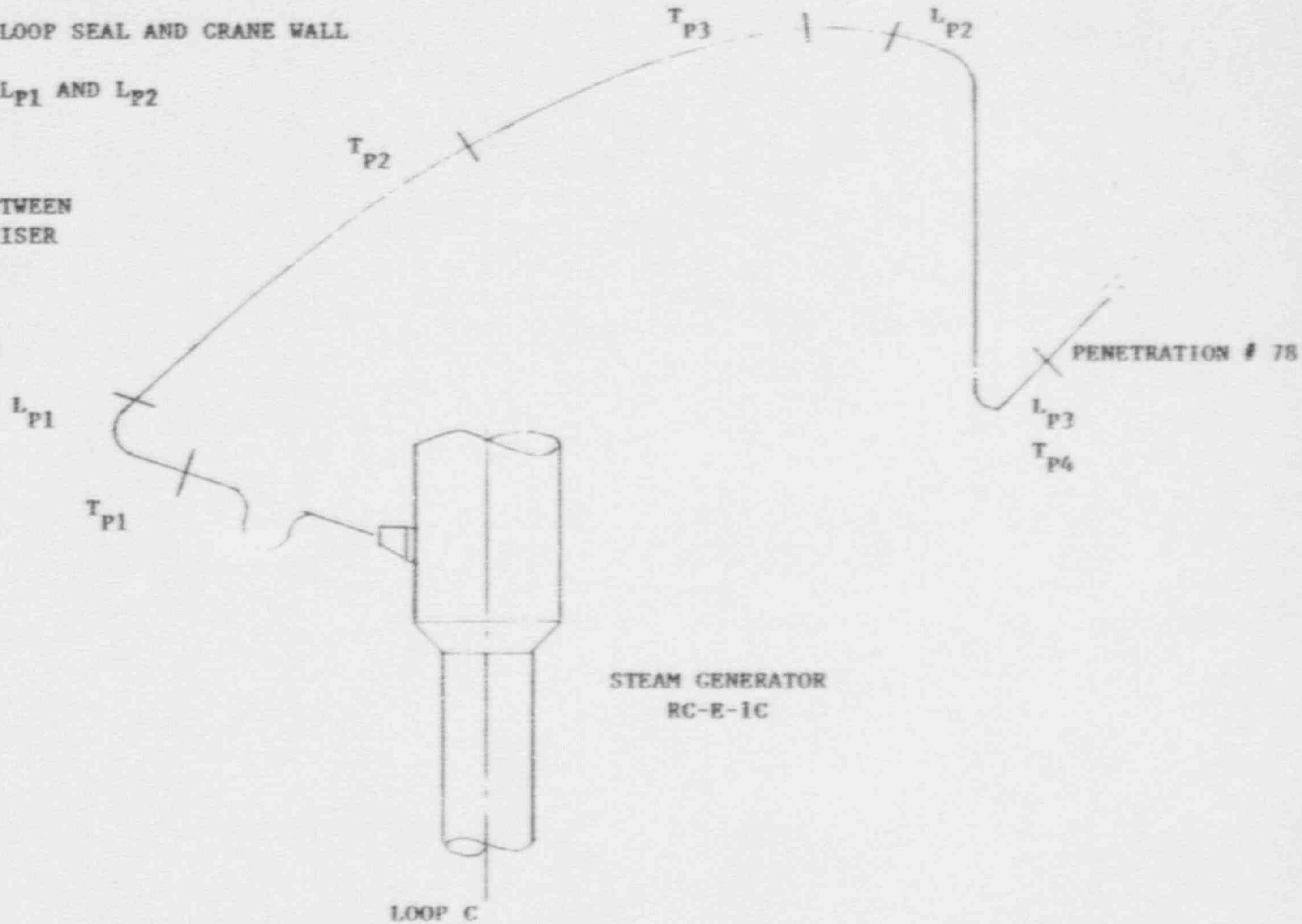


FIGURE 8.1.2.1-2

critical stress locations and will be easily accessible during the thermal sleeve installation, the wall thickness of these elbows should be measured. This will confirm that use of a .843 inch wall thickness for the elbows (a critical stress area) is appropriate. This will not be required if these elbows are replaced per Section 8.3.3.5.

8.1.2.4 PIPE SUPPORT MODIFICATIONS

Inspection of the monoball support R5 during 7R indicated that it may not have been functioning properly. Pipe stress analysis of the feedwater lines indicated that the remaining monoballs were potentially not functioning properly. The best correlation of loop A recorded data occurs when all loop A monoballs are considered as 3-way restraints (i.e., monoballs are designed as vertical only supports but are also restraining the axial and lateral directions). Analysis of the monoball supports indicate that they do not meet the plant design basis criteria. If these supports (H-3 and H-4 on loop A) are not functioning properly and they do not meet the plant design basis criteria, they must be replaced or redesigned to function as vertical only supports and strengthened to carry the additional global stratification loads. The monoball supports meet the one time loading requirements per ASME III Appendix F which allows continued operation of the unit (see Section 8.1.2.6).

8.1.2.5 PIPE SUPPORT INSPECTIONS

Several inspections of snubbers and hanger frames are also required to confirm assumptions. Snubbers to be as-built are HSS-201, HSS-202, HSS-203, HSS-204, HSS-205 HSS-206, HSS-212 AND HSS-212A. Frames to be as-built are H-3, H-4, H-5 and H-11.

8.1.2.6 INTERIM EVALUATION

All piping system components did not meet the design basis acceptance criteria when considering effects of global stratification and potentially locked monoballs. In order to justify the continued operation of the unit, appropriate interim acceptance criteria were developed and utilized in the evaluation of piping and supports. These alternate criteria were applied to qualify monoballs support frames and to evaluate pipe break stress levels. Appendix D discusses specific criteria utilized and affected piping system components. An acceptable limit for an OBE event, equal to .25 of the existing OBE limit, was determined for interim plant operation.

8.1.2.7 REVISE PIPE SUPPORT CRITERIA

Pipe support SH-6 was analyzed using ASME Boiler and Pressure Vessel Code Case N-318 [Ref. 9.64]. This code case provides alternate criteria for the evaluation of piping local stresses due to integral welded attachments. Code Case N-318 identifies current criteria available for the analysis of rectangular integral welded attachments. It provides relief from overly conservative stress indices and allowables provided certain geometric limitations are satisfied. Therefore, Code Case N-318 was adopted for the analysis of integral welded attachments.

8.2 STRONGLY RECOMMENDED CORRECTIVE ACTIONS

The strongly recommended corrective actions are primarily concerned with steam generator nozzle cracking and future possible water hammer events that were identified during the review for the root cause of the irregular pipe deformation pattern.

8.2.1 STEAM GENERATOR NOZZLE CRACKING

The recommended corrective actions for the steam generator nozzle taper transition cracking are a modification to install thermal sleeves to prevent reoccurrence of the cracking, and pre/post installation inspection of the feedwater line after the modification. These two actions are discussed below in Sections 8.2.1.1 and 8.2.1.2 respectively.

8.2.1.1 MODIFICATION

Analysis of the specific steam generator loop A nozzle taper transition and associated thermal transients indicates that the cracking could initiate after approximately 16 plant events.

Each of the first two times (1979 and 1988) when cracking was discovered, the elbows were simply replaced. A better solution than just replacing the elbows when they crack is to protect the taper transition from cracking by adding a thermal sleeve. The thermal sleeve will reduce the coefficient of heat transfer which is estimated to be as high as 2000 Btu/ft²-hr-°F without the thermal sleeve to as low as 20 Btu/ft²-hr-° F with the thermal sleeve [Refs. 9.16 and 9.17]. This will eliminate the thermal fatigue concern analyzed in Reference 9.20. Thermal sleeves should be installed and should consider thermal cycling data recorded during 7R. The thermal sleeve will be provided with two 90 degree short radius elbows which will replace one half of the existing loop seal on each loop and will aid in the installation. These elbows are also upgraded from grade B material (yield stress = 35 ksi) to grade C (yield stress = 40 ksi) to provide additional strength in a high stress location during global thermal stratification transients.

8.2.1.2 PRE/POST INSTALLATION INSPECTIONS

Preinstallation and post installation inspections are recommended for the implementation of the thermal sleeve modification. These inspections should identify and confirm all rupture restraint gaps. This information along with construction procedures will prevent misalignment of feedwater lines due to installation.

8.2.2 FUTURE POSSIBLE WATER HAMMER EVENTS

Steam generator water hammer has been identified at other operating plants of similar vintage. Inspections for two potential causes of steam generator water hammer to which Beaver Valley Power Station-Unit 1 is susceptible to are discussed below.

8.2.2.1 FEEDRING THERMAL SLEEVE INSPECTION

The feedring thermal sleeve of the steam generator must be inspected to assure that significant erosion of the slip fit connection has not occurred. This corrosion has been documented at Trojan Power Plant and was determined to be the cause of a severe water hammer event. The inspection can be easily performed during the installation of the steam generator nozzle taper transition thermal sleeve, when the two closest elbows of the loop seal to the steam generator are removed. Erosion of the slip fit must be corrected to prevent a significant water hammer event similar to Trojan's from occurring at Beaver Valley Power Station-Unit 1.

8.2.2.2 J-TUBE EROSION INSPECTION

Another possible cause of steam generator water hammer is the erosion of J-tubes or the loss of bottom plugs on the feedring. Only a 22 cubic inch steam void is considered to have caused the 40 kip loads postulated at Trojan. Several missing plugs and/or leaking J-tubes could allow enough steam to enter the feedring to cause a severe water hammer at Beaver Valley Power Station-Unit 1. The J-tubes and feedring plugs should be inspected. Missing plugs or severely eroded J-tubes should be replaced to prevent a significant water hammer event from occurring at Beaver Valley Power Station-Unit 1.

8.2.3 TACK WELD SHIM STACKS

The rupture restraint shims stacks on the Beaver Valley Power Station-Unit 1 feedwater lines have been dislodged several times due to water hammer events and thermal movements in combination with the irregular pipe deformation pattern. Tack welding the shim stacks would better maintain the appropriate rupture restraint gaps. This would eliminate periodic replacement efforts by construction and maintain the appropriate rupture restraint gaps. Existing design basis water hammer and seismic displacements would not contact the rupture restraints however global stratification displacements can close the gaps.

8.3 RECOMMENDED CORRECTIVE ACTIONS

The recommended corrective actions are primarily concerned with future possible water hammer events and other concerns. These action items provide additional information in the event of further inquiry and minimize the impact of various transients by replacing materials or by limiting conditions. The future possible water hammer is discussed in Section 8.3.1 and installation of MIN-K insulation is discussed in Section 8.3.2 and is applicable to both future possible water hammer and the other concerns as well as routine inspections. The other concerns are discussed in Section 8.3.3.

8.3.1 FUTURE POSSIBLE WATER HAMMER

Two additional actions are identified below whose implementation would further reduce the probability of a feedwater system water hammer.

8.3.1.1 PERIODIC REVIEW OF FRV AND TURBINE BUILDING PIPING

Failure of the main feedwater regulating valve (FRV) linkage cause a significant water hammer event at Beaver Valley Power Station-Unit 1 in 1981. The linkage failure caused primarily by resonance/vibration of the valves and piping has only been partially corrected. A review of the resonant period should be undertaken to avoid or eliminate the resonant peaks for this piping system. This will prevent a future water hammer due to FRV failure. For example, steps should be taken to decouple/detune system piping from the valve stem/plug resident frequency at the 17 Hz range.

8.3.1.2 LIMIT MAXIMUM AUXILIARY FEEDWATER FLOW

A limit on the maximum AFW flow rate should be established and implemented in order to reduce the magnitude of a steam generator bubble collapse water hammer. Reducing AFW flow will slow down the rate of the steam bubble collapse (if a steam bubble exists in the steam generator feedring) which will reduce the magnitude of water hammer loads. This was recommended in Reference 9.58. Beaver Valley Power Station-Unit 1 currently uses an AFW flow rate of approximately 450 gpm per steam generator. This should be reduced to 150-200 gpm. Although 150 gpm is recommended by References 9.58 and 9.37, the current minimum design flow is approximately 175 gpm. The BV-1 plant specific steam generator flow requirements may require a flow rate greater than 150, gpm, but one less than 175 gpm can be achieved.

8.3.2 INSTALL MIN-K INSULATION AT ALL RUPTURE RESTRAINTS

Installation of MIN-K insulation at all feedwater rupture restraints inside containment will facilitate inspection of the rupture restraint gaps. Future required inspections of these gaps are considered to be likely based on the feedwater lines operating history and concerns about water hammer and global stratification. The installation of MIN-K insulation would require a review of affected design calculations to ensure design basis requirements are maintained.

8.3.3 OTHER CONCERNS

Recommended corrective actions for other concerns include the following items to:

a. Review global stratification effects in the MSVH and Turbine Building (see Section 8.3.3.1).

b. Perform sample NDE's inside containment to verify wall thickness (see Section 8.3.3.2).

c. NDE the auxiliary feedwater nozzle in the MSVH (see Section 8.3.3.3).

d. Replace the remaining loop seal grade B elbows with grade C material (see Section 8.3.3.4).

e. Inspect other monoball supports (see Section 8.3.3.5)

These issues are discussed in detail in the following paragraphs.

8.3.3.1 REVIEW GLOBAL STRATIFICATION EFFECTS IN THE MSVH AND TURBINE BUILDING

The feedwater lines inside the MSVH and Turbine Building should be reviewed for global thermal stratification effects. Instrumentation and selective nondestructive examination of these lines should be undertaken to ensure that no detrimental unanalyzed condition is occurring in the MSVH and Turbine Building.

8.3.3.2 PREFORM SAMPLE NDE'S TO VERIFY WALL THICKNESS

Concerns exist from previous evaluations that portions of the feedwater lines inside containment have wall thickness of .750 inches instead of .843 inches. Selective nondestructive examination (NDE) of each feedwater line would determine the magnitude of the feedwater line wall thinning problem and help substantiate the existing analysis. The loop seal elbows are exempted from this recommendation because their inspection is required per Section 8.1.3.3.

8.3.3.3 NDE AFW NOZZLE IN MSVH

The auxiliary feedwater nozzle in the MSVH is subjected to relatively high thermal stresses after a reactor trip. After a reactor trip the auxiliary feedwater system is activated and water from tank WT-TK-10 at a temperature as low as 45° F is injected into 441° F feedwater line. NDE of this connection would assure integrity of the nozzle and of the remaining piping system up to the steam generator nozzle. The AFW connection is the most thermally stress fatigued region of the feedwater system with the exception of the steam generator nozzle because of the 45° F to 441° F step change. Fortunately the number of events is relatively small and no indications would be expected upon NDE.

8.3.3.4 REPLACE REMAINING LOOP SEAL GRADE B ELBOWS WITH GRADE C MATERIAL

The four existing steam generator loop seal short radius elbows on each feedwater line are currently stamped as grade B material. These elbows are the most highly stressed components of the system due to global thermal stratification. The two elbows closest to the steam generator are being replaced with grade C material during the thermal sleeve installation. Grade B and C materials have yield stresses of 35 and 40 ksi respectively Replacement of the remaining two elbows in each loop seal could also be made thereby increasing the margin of safety. These elbows must be removed to facilitate the installation of the new thermal sleeves.

8.3.3.5 INSPECT OTHER MONOBALL SUPPORTS

All other monoball supports on Beaver Valley Power Station-Unit 1 that are not addressed in this report should be inspected to ensure that they are constraining the pipe as designed.

9.0 REFERENCES

9.1 DBD-24A, Design Basis Document for BV-1 Steam Generator Feedwater System, Rev. 0.

9.2 DBD-24B, Design Basis Document for the BV-1 Auxiliary Feedwater System, Rev. 0.

9.3 Operating Manual Chapter 24, BV-1 Steam Generator Feedwater System, Rev. 11.

9.4 UFSAR Section 5.2.6, Missiles and Pipe Rupture, Rev. 1.

9.5 NUREG 0800, Section 3.6.2, Determination of Rupture Locations and Dynamic Effects Associated with the Postulated Rupture of Piping, Rev. 1, dated July 1981.

9.6 Mechanical Engineering Branch Technical Position, MEB 3-1, Postulated Rupture Locations in Fluid System Piping Inside and Outside Containment, Rev. 2, dated June 1987.

9.7 Calculation 11700.34-NP(B)-783X, Problem 783-Pipe Stress Calculation for Steam Generator Feedwater Piping Inside Containment (RC-E-1A), Rev. 2, dated November 19, 1990.

9.8 Calculation 11700.34-NP(B)-784X, Problem 784-Pipe Stress Calculation for Steam Generator Feedwater Piping Inside Containment (RC-E-1C), Rev. 2, dated November 19, 1990.

9.9 Calculation 11700.34-NP(B)-785X, Problem 785-Pipe Stress Calculation for Steam Generator Feedwater Piping Inside Containment (RC-E-1B), Rev. 2, dated November 19, 1990.

9.10 Calculation 8700-DMC-2358, Feedwater Rupture Restraint Gap Cold Set Evaluation, Rev.0, dated December 20, 1989.

9.11 Calculation 8700-DMC-2355, Analysis of Main Feedwater Lines, As Found During 7R, Rev. 0, dated February 5, 1990.

9.12 NRC IE Bulletin No. 79-13, Cracking in Feedwater Piping, dated June 25,1979.

9.13 UCRL-52265 "An Investigation of Pressure Transient Propagation in Pressurized Water Reactor Feedwater Lines", Lawrence Livermore Laboratory dated July 22, 1977.

9.14 BV-1 Response to NRC I.E. Bulletin 79-13, Stress Analysis of the DLW Feedwater Piping, dated June 25, 1977.

9.15 Not Used

9.16 W.H. Bamford, A. Thurman and M. Mahlab, Fatigue Crack Growth in Pressurized Water Reactor Feedwater Lines, ASME Paper 81-PVP-2 (1981).

9.17 A. L. Thurman, M.S. Mahlab and R.E. Boylstein, 2-D Finite Element Analysis for the Investigation of Feedwater Line Cracking in PWR Steam Generators, ASME Paper 81-PVP-3 (1981).

9.18 M.H. Hu, J.L. Houtman and D.H. White, Flow Model Test for the Investigation of Feedwater Line Cracking for PWR Steam Generators, ASME Paper 81-PVP-4 (1981).

9.19 R. Braschel, M. Miksch and G. Schucktanz, Thermal Stratification in Steam Generator Feedwater Lines, Trans, ASME Vol. 106, February 1984, pp. 78-85.

9.20 Calculation 01296-NP(B)-4001, Pipe Stress Analysis of Local Thermal Stratification Fatigue Analysis of Beaver Valley Power Station-Unit 1 Loop A Feedwater Nozzle Taper Transition and Root Cause Evaluation for the Observed 7R Irregular Deformation Pattern, Rev. 0, dated November 19, 1990.

9.21 NRC-AEOD STUDY, Review of Thermal Stratification Operating Experience, by Office for Analysis and Evaluation of Operational Data, dated March 1990, Prepared by Nelson T. Su.

9.22 SWEC Report, Request for Additional Information, Evaluation of Main Feedwater Piping Vibrations, submitted under Docket No. 50-334, dated January 21, 1977.

9.23 Letter ND1NSM:2490, Feedwater System Perturbations dated January 8, 1987.

9.24 NUREG-0582, Water Hammer in Nuclear Power Plants, dated July 1979.

9.25 NUREG/CR-2059, Compilation of Data Concerning Known and Suspected Water Hammer Events in Nuclear Power Plants, dated May 1981.

9.26 NUREG/CR-2781, Evaluation of Water Hammer Events in Light Water Reactor Plants, dated July 1982.

9.27 NUREG-0918, Prevention and Mitigation of Steam Generator

Water Hammer Events in PWR Plants, dated November 1982.

9.28 NUREG-0927, Evaluation of Water Hammer Occurrence in Nuclear Power Plants, Rev. 1, dated March 1984.

9.29 NUREG-0993, Regulatory Analysis for USI A-1, "Water Hammer", Rev. 1, dated March 1984.

9.30 NUREG/CR-3939, Water Hammer Flow Induced Vibration and Safety/Relief Valve Loads, dated September 1984.

9.31 NUREG-0291, An Evaluation of PWR Steam Generator Water Hammer, dated December 31, 1976.

9.32 Not used.

9.33 D. A. Van Duyne and W. Yow, Water Hammer Events Under Two- Phase Flow Conditions, TO 89-56, dated December 10, 1989.

9.34 EPRI Research Project 2856-3, Task 5 - Water Hammer Prevention, Diagnostic and Assessment Guidelines, dated March 23, 1990.

9.35 J. Lynch, Impedance-Coupled Valve and Fluid System Instability.

9.36 Trojan Report, Main Feedwater Piping Restraint Failure, submitted under Docket No. 50-334, dated June 15,1987.

9.37 NUREG-0800, SRP Section 10.4.7, Condensate and Feedwater System, Rev. 3, dated April 1984.

9.38 Branch Technical Position ASB 10-2 , Design Guidelines for Avoiding Water Hammers in Steam Generators, Rev. 3, dated April 1984.

9.39 Engineering Memorandum 60322, Feedwater Restraint No. 38, dated May 6, 1981.

9.40 Engineering Memorandum 20724, Acceptance of Shimming of Feedwater Restraint No. 38, dated May 7, 1981.

9.41 Report No. 01036-535-AV1, Revision 0, dated DRAFT "Loop A Feedwater Line Recorded Data-Beaver Valley Unit 1 Post 7R Heatup".

9.42 NRC Bulletin No. 88-11, Pressurizer Surge Line Thermal Stratification, dated December 20, 1988.

9.43 Stone and Webster Calculation No. 17801-NP(B)-X005-FA-50K, Water Hammer Analysis of the Main Feedwater System

Due to Check Valve Closure Following Pump Trip and Flow Control Valve Closure, Rev. 0, dated January 18, 1989.

9.44 STRUDL-SW, ST-346, Computer Code for the Analysis of Structural Elements.

9.45 NUPIPE-SW, ME-110, Computer Code for the Analysis of Piping Elements.

9.46 ANSYS-4.4 PC based Engineering Analytical Computer Code.

9.47 Correlative Analysis of ANSYS 4.4 PC And STRUDL-SW Thermal Stratification Profiles for Main Feedwater Piping Beaver Valley Power Station-Unit 1, by Carol Allen, DRAFT.

9.48 Stone and Webster Pipe Support Analysis
a. 11700.34-NP(B)-783-Z 1 through 11
b. 11700.34-NP(B)-784-Z 1 through 3
c. 11700.34-NP(B)-785-Z 1 through 6
d. 8700-DMC-2335
e. 8700-DMC-2329

9.49 Metallurgical Examination Report Letter: NDIMNE:4278 dated September 2, 1988 DLC Nuclear Group to: T.P.Noonan from: N.R.Tonet.

9.50 STDRAW, GR-147, Computer Code for Plotting STRUDL-SW Models.

9.51 NUDRAW, GR-159, Computer Code for Plotting NUPIPE-SW Models.

9.52 1981 Water Hammer Report Response Filed Under LER 81-032 (Westinghouse).

9.53 Calculation 01296-NP(B)-4002 Feedwater Nozzle Load Evaluation for Steam Generators RC-E-1A, 1B & 1C, Rev 0, dated November 19, 1990.

9.54 Calculation 01296-NP(B)-4003 Containment Penetration Review (Penetrations No. 76, 77 & 78 Only) For Loads Resulting From Thermal Stratification Analysis, Rev. 0, dated November 19,1990.

9.55 Not used

9.56 Calculation 8700-DSC-156-T, Embedment Plate Analysis for Feedwater Loop A, dated November 14, 1990.

9.57 IR 89-113, Damaged Shim Packs on Pipe Restraint.

9.58 Westinghouse Technical Bulletin NDS-TB-75-7, Rev. 1, dated March 9, 1977.

9.59 NRC Information Notice No. 84-87, Piping Thermal Deflection Induced by Stratified Flow, dated December 3, 1984.

9.60 HTLOAD, ME-142, Computer Code for Heat Transfer and Thermal Loading.

9.61 LER 81-032

9.62 ANSI B31.1, Power Piping Code, 1967.

9.63 ASME Boiler and Pressure Vessel Code, Section III Appendix F, 1989.

9.64 ASME Boiler and Pressure Vessel Code Case N-318-2, dated July 12, 1984, 'Procedure for Evaluation of the Design of Rectangular Cross Section Attachments on Class 2 or 3 Piping, Section III, Division 1.

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9.66 Calculation 8700-DSC-156-V, Embedment Plate Analysis for Feedwater Loop C, dated November 14, 1990.

9.67 DCP-248, Feedwater Control Valve Modification, Implemented During Second Refueling Outage, March 1982.

9.68 Letter from A. Schwencer, NRC to C. Goodman,Jr., Portland General Electric Company, Subject: Safety Evaluation Report for Steam Generator Water Hammer At Trojan Nuclear Plant, Docket No. 50-344, dated October 18, 1979.

9.69 Letter from J. L. Williams, Portland General Electric Light Company, to N. R. Butler, NRC, Subject: Report on Testing of Auxiliary Feedwater Addition, Following J-Tube Modifications to the S/Gs of the Trojan Nuclear Plant,Docket No. 50-334, dater October 21,1975.

APPENDIX A

10.1 CHRONOLOGY OF EVENTS POST 7R HEATUP

APPENDIX A

DATE	TIME	EVENT
12-14-89	0615	START TO FILL STEAM GENERATOR THERE WAS NO ACTIVITY BEFORE THIS DATE
12-14-89	1752	COMPLETED FILL OF ALL STEAM GENERATORS USED AUXILIARY FEEDWATER PUMP 3B PLANT STATUS RCS PRESSURE 300 PSI RCS TEMPERATURE 256° F
12-15-89	1900	MOV-FW-151D XF WILL NOT CLOSE ELECTRICALLY
12-15-89	1945	B STEAM GENERATOR LEVEL INSTRUMENTS DO NOT CORRELATE (485, 486) A AND C LOOPS CONSIDERED OPERABLE
12-15-89	1956	2/3 B STEAM GENERATOR LEVELS ABOVE 75% PIPE STRATIFICATION OCCURRED FEEDWATER ISOLATION SIGNAL TO MOV-FW-150A,XB WHICH CLOSED AUX FEED INJECTION RESULTED PLANT STATUS MODE 5 RCS PRESSURE 300 PSI RCS AVERAGE TEMPERATURE 265° F
12-15-89	2029	SHUT OFF AUX FEED PUMP
12-16-89	0300	STROKING MOV'S FW-151A AND C NOT B WITH AND WITH OUT FLOW
12-16-89	0530	STROKED MOV,S-FW-151-B,D,AND F
12-16-89	1148	WORKING ON B STEAM GENERATOR LEVEL TRANSMITTER 485,486 FEEDWATER ISOLATION SIGNAL MOV'S-156-A, B AND C CLOSE
12-17-89	1915	INSTALLED DUMMY SIGNALS ON LT-FW-485 AND 486 TO WORK ON THEM
12-18-89	0708	ENTERED MODE 3 RCS PRESSURE APPROX 300 LBS RCS TEMPERATURE APPROX 256° F

12-18-89	1323	OPENED TV-MS-101; STEAM GENERATOR SWELL OCCURRED FEEDWATER ISOLATION SIGNAL
12-19-89	0500	FT-FW-476 EXHIBITING SPIKING DECLARED OUT OF SERVICE (005)
12-19-89	1641	SHUT DOWN FW-P-1A
12-19-89	1853	ATTEMPTED TO START FW-P-1B
19-19-89	1905	REATTEMPTED TO START PUMP 1B
12-19-89	2104	REATTEMPTED TO START PUMP 1B
12-19-89	2341	WHILE RUNNING FW-P-2 FOR OST FOUND VALVE FW-36 LEAKING
12-20-89	0212	STARTED PUMP FW-P-1B
12-20-89	0217	SHUT DOWN FW-P-1A
12-20-89	0320	START UP PUMPS FW-P-1A AND FW-P-1B
12-20-89	0441	START UP FW-P-2 FOR OST
12-20-89	0630	DECLARE FT-FW-477 'A' STEAM GENERATOR FEED FLOW 005 ALARM AND CONTINUOUSLY SPIKING
12-20-90	09[illegible]0	FT-FW-476 DECLARED OPERABLE BASED ON SUITABLE OUTPUT AS SEEN ON RECORDER
12-20-89	1355	DURING MSP 104 A STEAM GENERATOR DROPPED TO 25% WITH F-477 TRIPPED FOR FSP
12-22-89	1004	FT-FW-477 DECLARED OPERABLE FOLLOWING STABLE BEHAVIOR ON RECORDER TRACE
12-24-89	1902	COMMENCED REACTOR STARTUP
12-25-90	0000	ENTERED MODE 2
12-26-90	0800	ENTERED MODE 1
12-26-90	0852	LATCHED TURBINE
12-26-89	1043	TURBINE TRIP
12-26-89	1325	GENERATOR TRIPPED ON OVER EXCITATION
12-26-89	1413	TURBINE REATTACHED

12-26-89	1457	TURBINE TRIP
12-27-90	0120	APPROX 29% POWER
12-27-89	0121	REACTOR TRIP TURBINE TRIP MAIN FEEDWATER ISOLATION AUX FEEDWATER INJECTION RESULTS WITH ..JX FEED PUMPS 3A AND 3B MODE 3 RESULT OF REACTOR TRIP
12-27-89	0124	STEAM GENERATOR LEVEL (APPROX 11.8 INCHES FEEDRING NO LONGER COMPLETELY SUBMERGED
12-27-89	0128	STOP BOTH MAIN FEED PUMPS (1A AND 1B)
12-27-89	0144	STOP AUX FEED PUMP 3B
12-27-89	0152	START MAIN FEED PUMPS
12-27-89	0243	STOP AUX FEED PUMP 3A
12-27-89	0250	ATTEMPTED TO OPEN MOV FW-150A MAIN FEED REALIGNED
12-27-89	0912	STOP BOTH MAIN FEED PUMP 1A AND 1B
12-27-89	1921	REACTOR CRITICAL (I.E., MODE 2)
12-27-89	2300	PLANT AT 10% POWER (BEGIN 8 HOUR SOAK AT 10% POWER)
12-28-89	0700	COMPLETE 8 HOUR SOAK AT 10% POWER
12-28-89	????	INCREASE TO 24% POWER
12-28-89	1500	RAISE POWER TO 30% POWER FOR 30 HOUR SOAK
12-28-89	1700	BEGIN 30 HOUR STABILIZATION AT 30% POWER
12-29-89	ALL	30% POWER
12-30-89	ALL	30% POWER
12-31-89	ALL	30% POWER
01-01-90	???	ELEVATE TO APPROX 50% POWER
01-01-90	???	ELEVATE TO APPROX 58% POWER
01-01-90	1500	ELEVATE TO 70% POWER

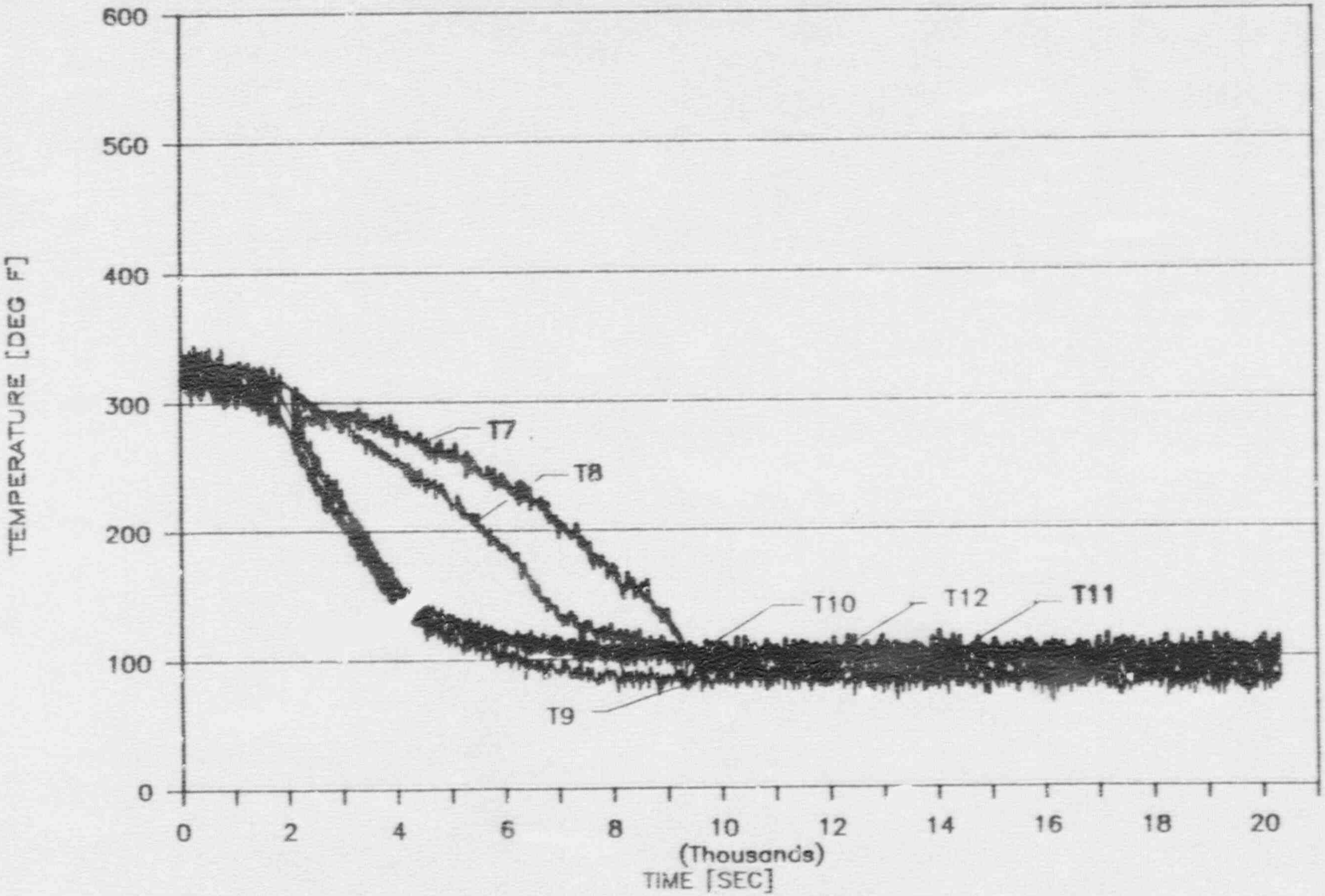
01-04-90	???	ELEVATE TO 88% POWER
01-05-90	???	ELEVATE TO 96% POWER
01-19-90	1632	COMMENCE PLANT SHUT DOWN
01-19-90	1702	SHUT DOWN FW-P-1A ISOLATE MAIN FEED REGULATING VALVES
01-19-90	1803	TURBINE TRIPPED

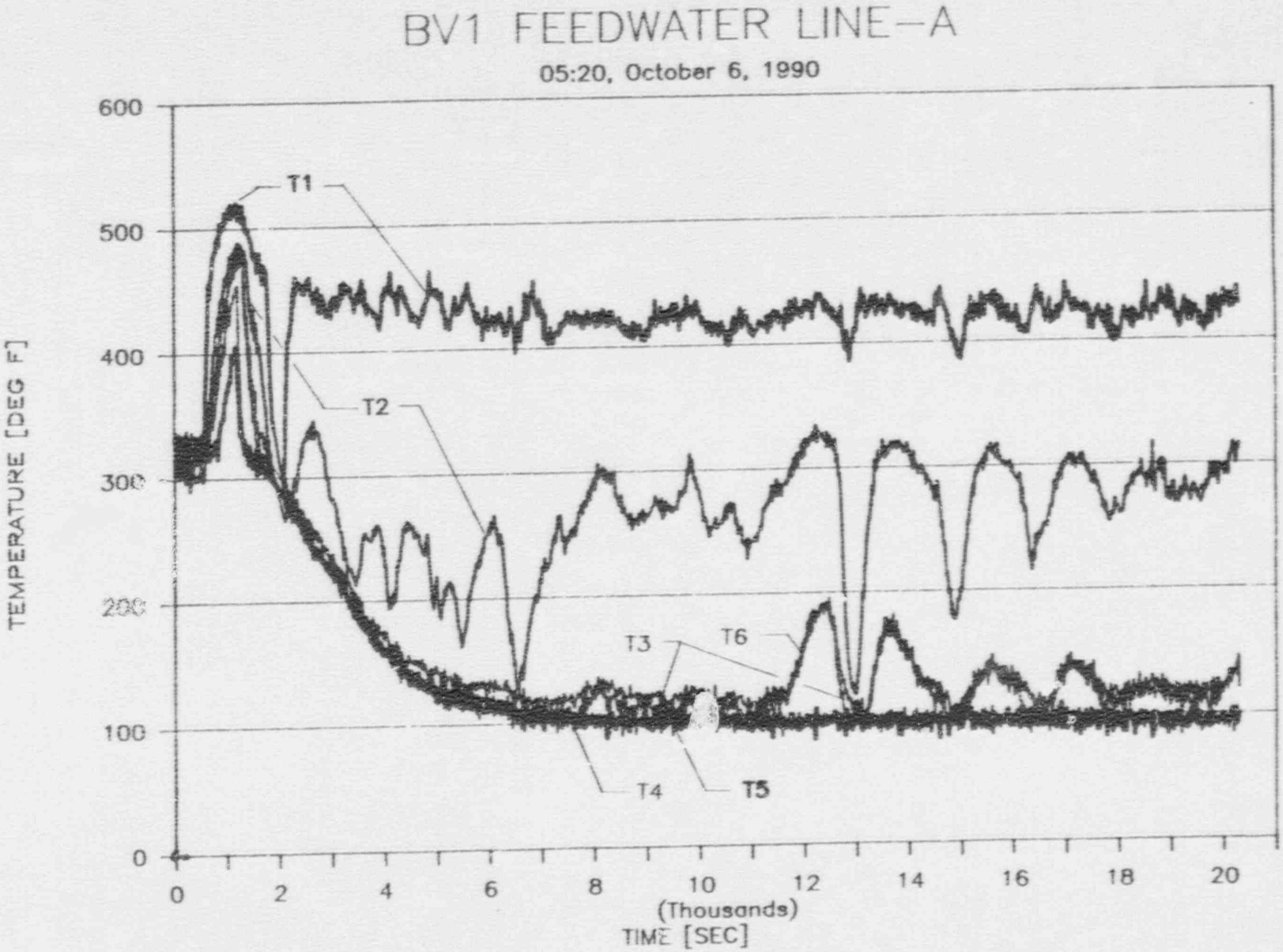
APPENDIX B

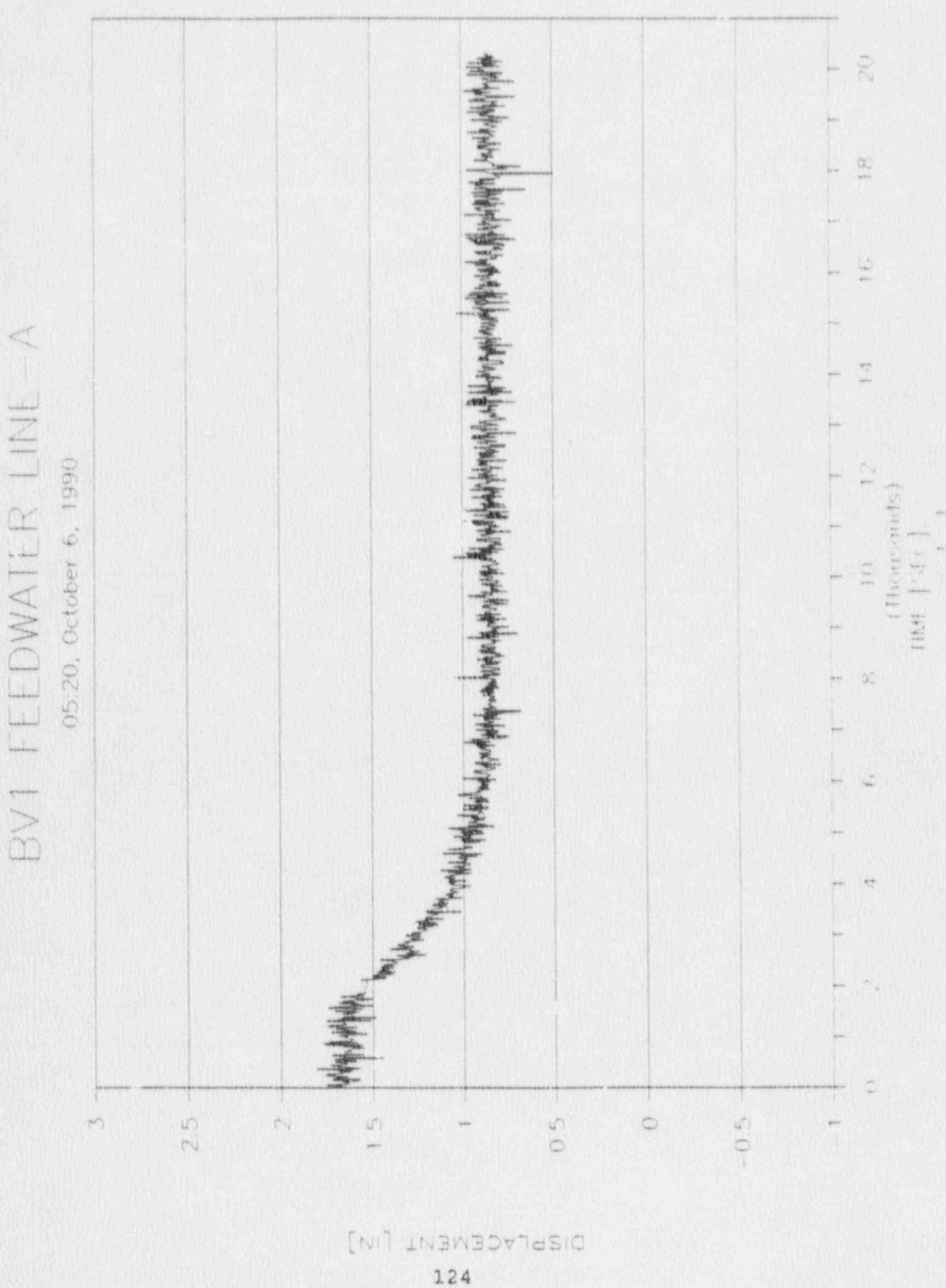
10.2 GRAPHS OF OCTOBER 6, 1990 MANUAL COOLDOWN

BV1 FEEDWATER LINE-A

05:20, October 6, 1990




BV1 FEEDWATER LINE-A
05:20, October 6, 1990
TEMPERATURE [DEG F]
600
500
400
300
200
100
0
T1
T2
T3
T4
T5
T6
0
2
4
6
8
10
12
14
16
18
20
(Thousands)
TIME [SEC]


BV1 FEEDWATER LINE-A
05:20, October 6, 1990
DISPLACEMENT [IN]
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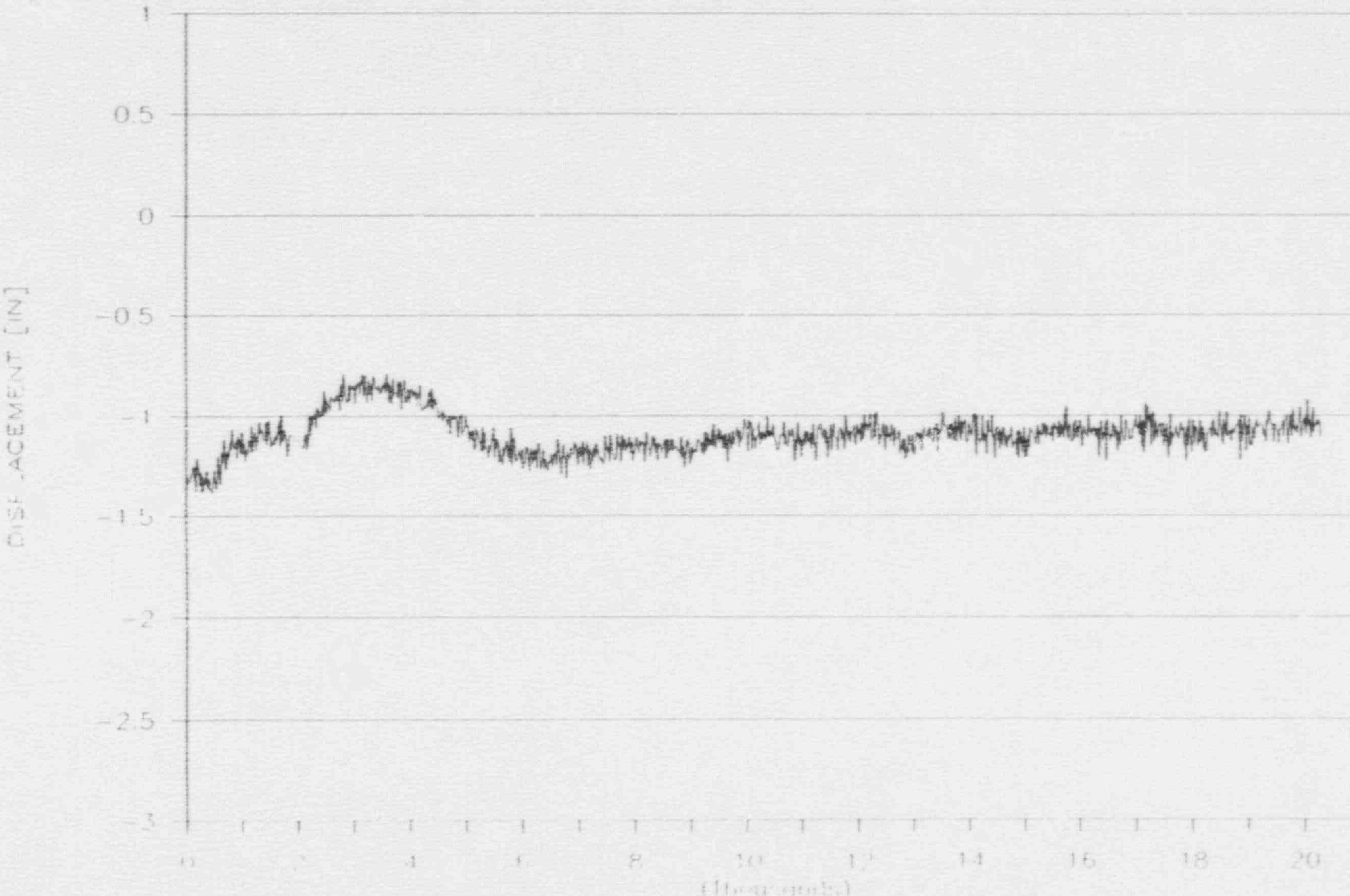
2
1.5
1
0.5
0
-0.5
-1
0
2
4
6
8
10
12
14
16
18
20
(Thousands)
TIME [SEC]

BV1 FEEDWATER LINE-A

05:20, October 6, 1990



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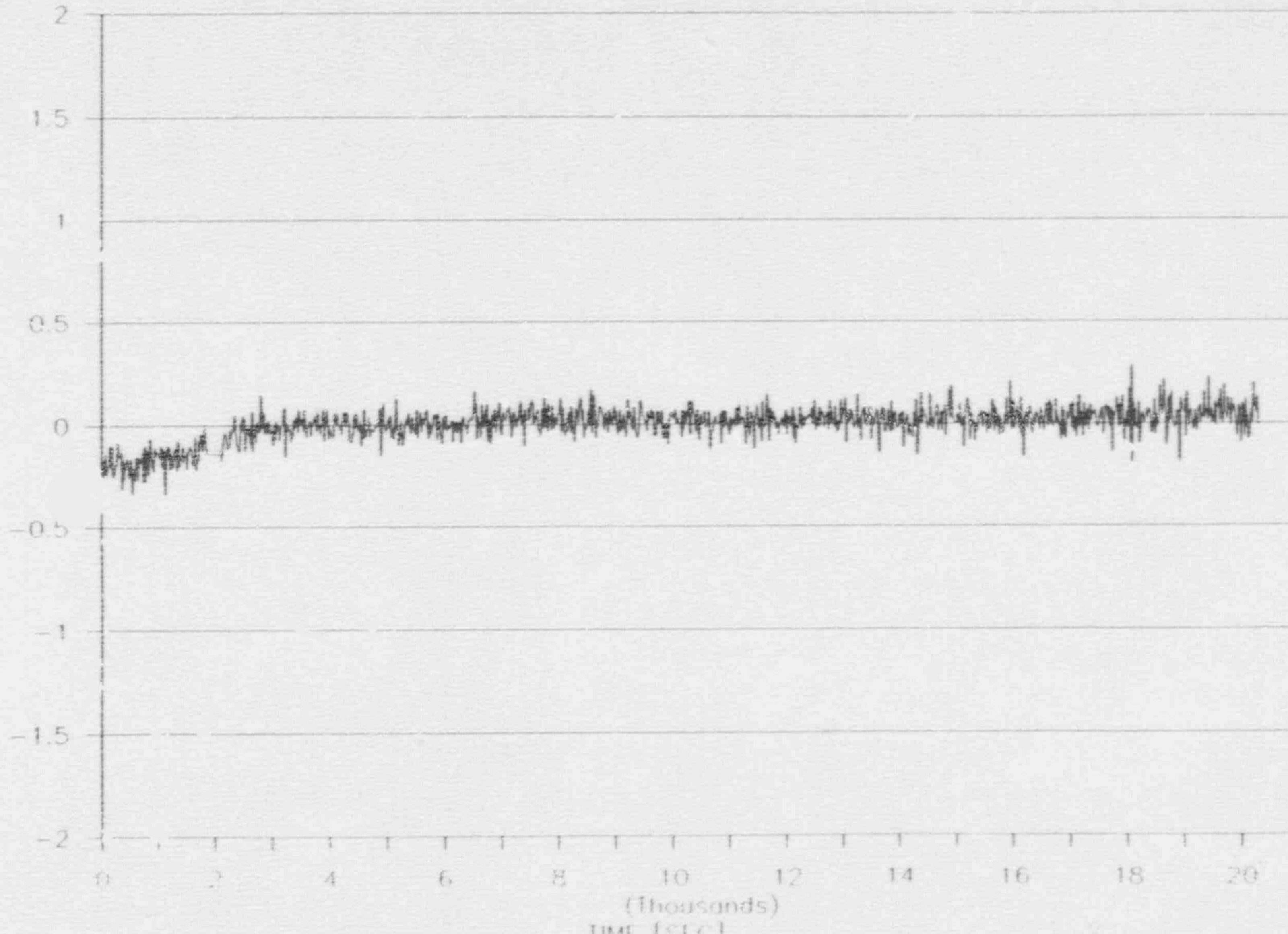
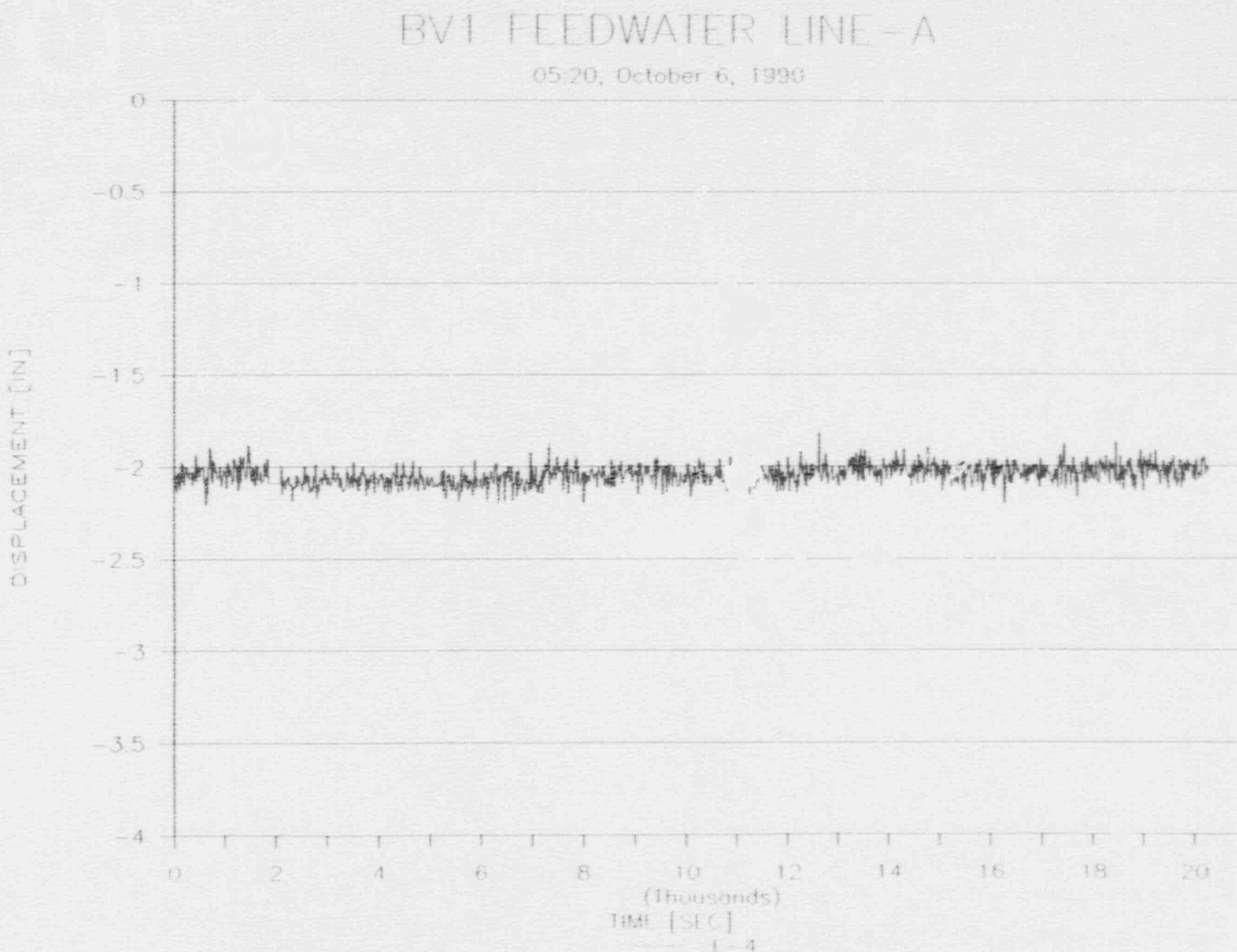


L-3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05:20, October 6, 1990
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-0.5
-1
-1.5
-2
-2.5
-3
-3.5
-4
DISPLACEMENT [IN]
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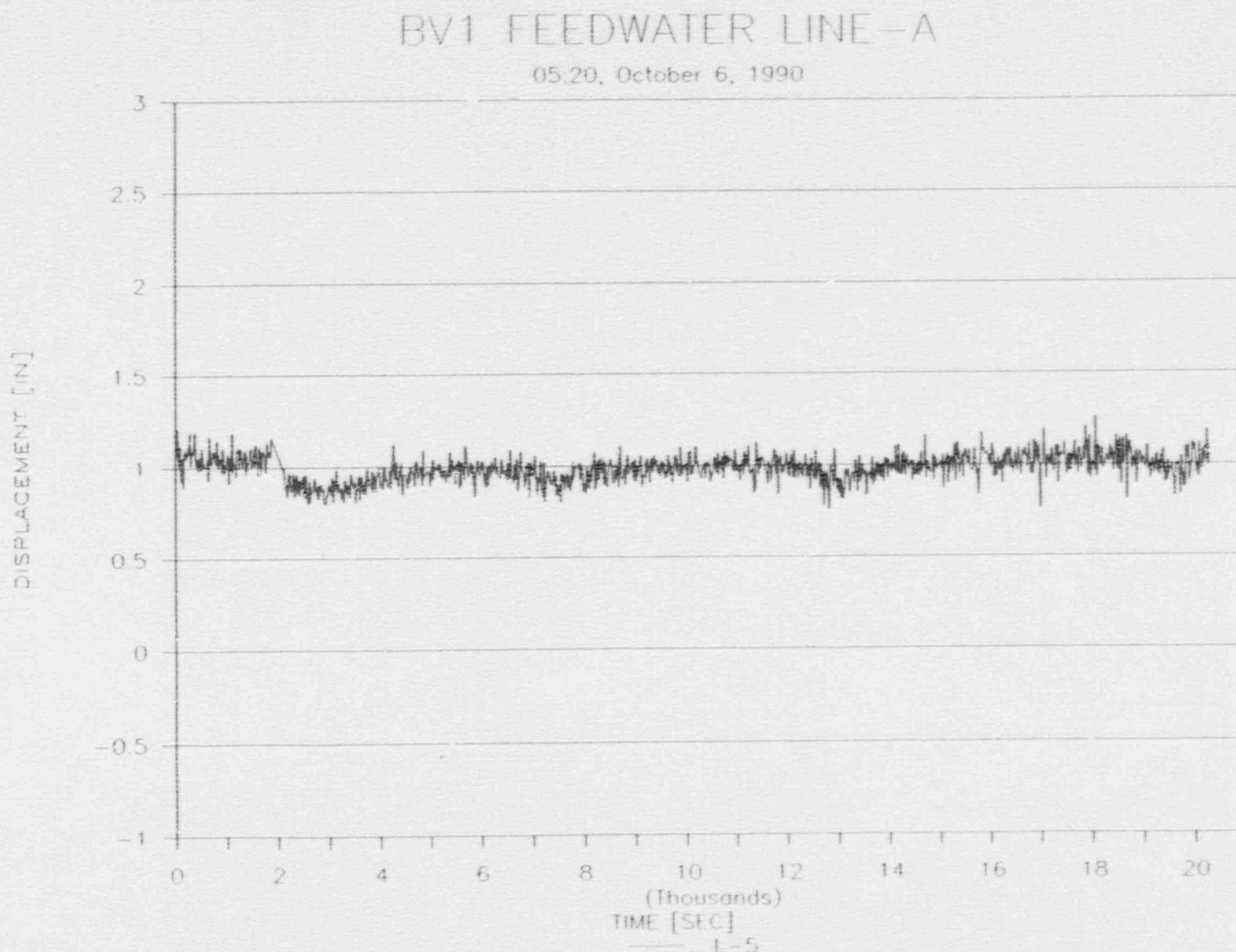
2
4
6
8
10
12
14
16
18
20
(Thousands)
TIME [SEC]
L-4


BV1 FEEDWATER LINE-A
05:20, October 6, 1990
DISPLACEMENT [IN]
3
2.5
2
1.5
1
0.5
0
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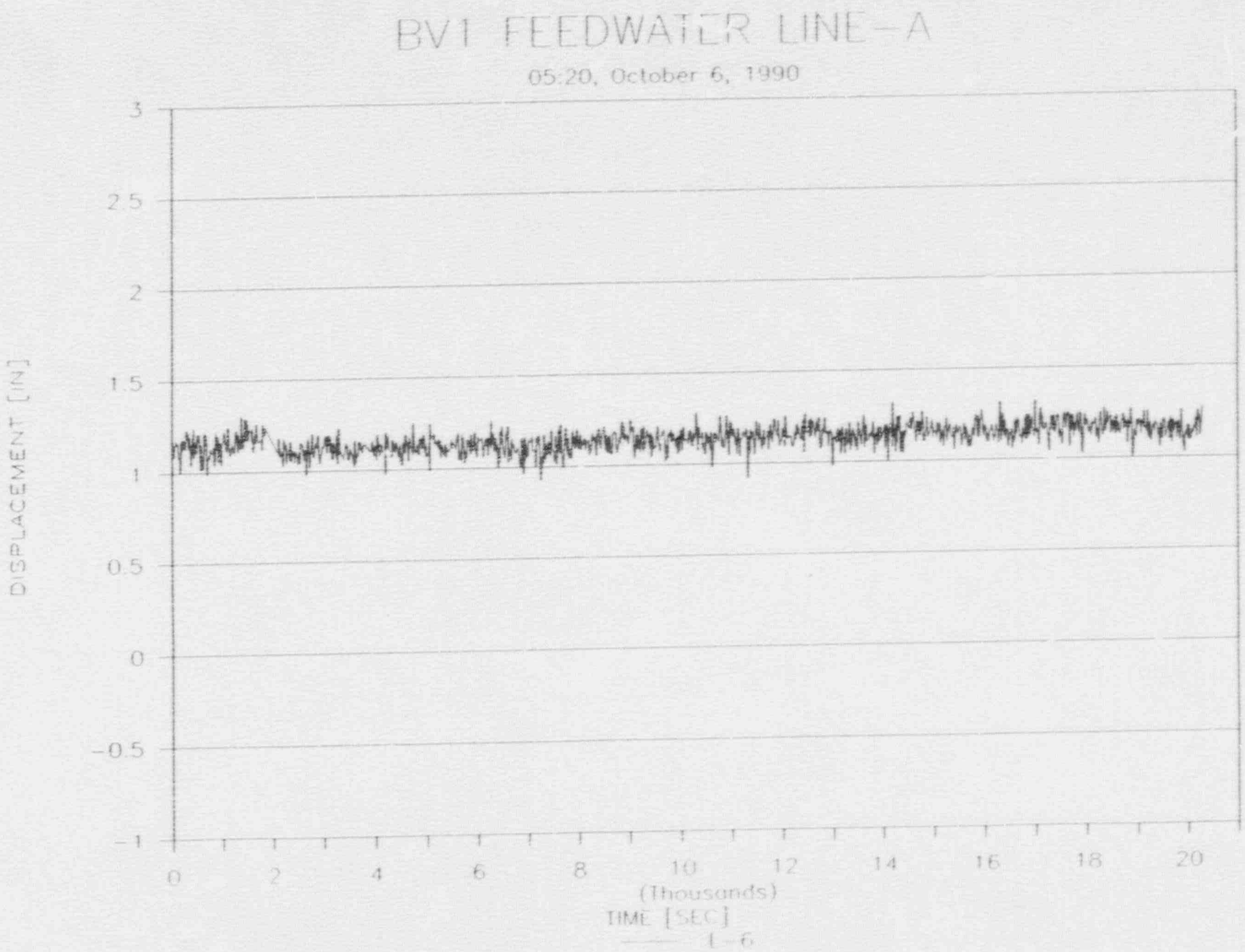
-1
0
2
4
6
8
10
12
14
16
18
20
(Thousands)
TIME [SEC]
L-5


BV1 FEEDWATER LINE-A
05:20, October 6, 1990
DISPLACEMENT [IN]
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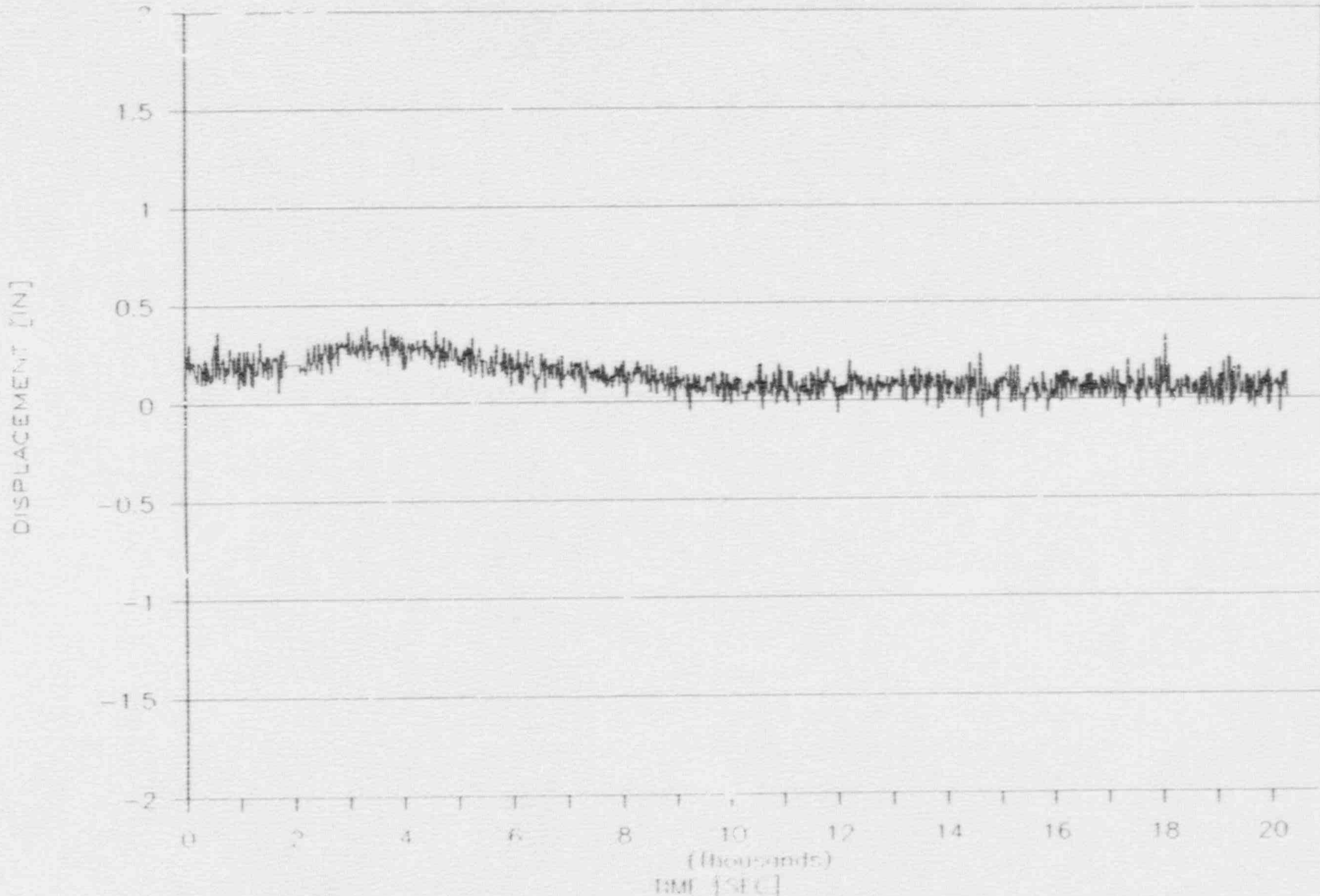
2.5
2
1.5
1
0.5
0
-0.5
-1
0
2
4
6
8
10
12
14
16
18
20
(Thousands)
TIME [SEC]
1-6

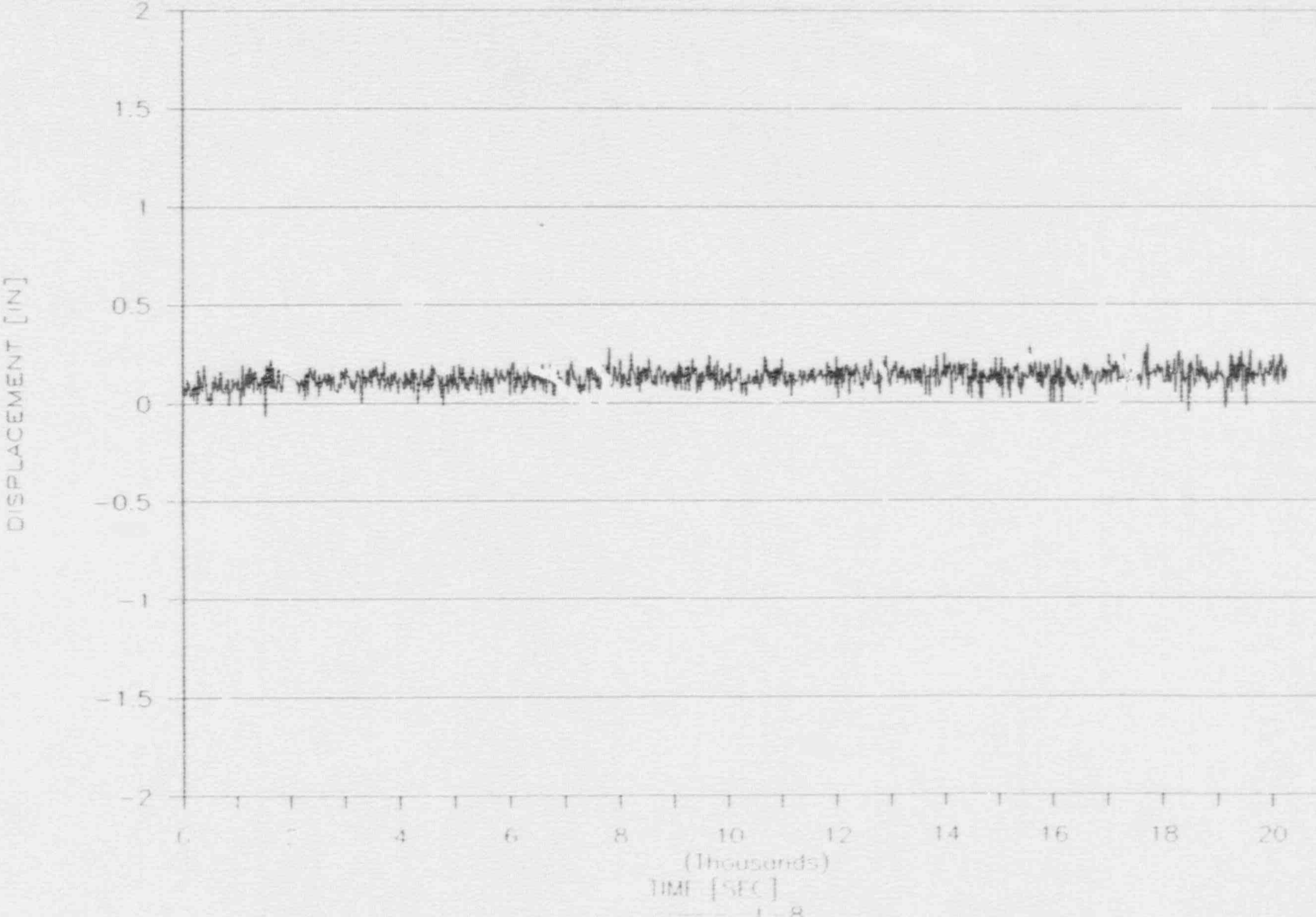
BV1 FEEDWATER LINE-A

05:20, October 6, 1990



BV1 FEEDWATER LINE-A

05.20, October 6, 1990



APPENDIX C

10.3 PLANT EVENT DESCRIPTIONS

APPENDIX C

EVENT	ACTIVITY	RESULTS
1. Heatup (1)	Hot stand-by cycling from Mode 3 to Mode 1 low power operation.	Significant cycling of local stratification at steam generator nozzle from Mode 3 to low power operation.
2. Heatup (2)	From Mode 5 to Mode 3 and then returning to Mode 5	Produced local stratification. No significant global stratification.
3. Manual cooldown (1)	From Mode 1 to Mode 3 and then returning to Mode 1	Intrasystem global stratification. Significant local stratification. Not counted as a heatup cycle.
4. Manual cooldown (2)	Mode 1 to Mode 5 with subsequent heatup	Produced intrasystem global stratification. Significant local stratification. Subsequent heatup counted as a heatup event.
5. Reactor Trip (1)	Auxiliary feedwater injection resulting in cooldown to Mode 5.	Produced significant cycling of local stratification at the steam generator nozzle. Produced global stratification. Not counted as a heatup event.
6. Reactor Trip (2)	Auxiliary feedwater injection resulting in cooldown to Mode 3 and heatup back to Mode 1	Produced significant cycling of local stratification at the steam generator nozzle. Subsequent heatup counted as a heatup event.

APPENDIX D

10.4 JUSTIFICATION FOR CONTINUED OPERATION

APPENDIX D

BEAVER VALLEY POWER STATION-UNIT 1
FEEDWATER SYSTEM EVALUATION
JUSTIFICATION FOR CONTINUED OPERATION (JCO)
DECEMBER 13, 1991

Duquesne Light Company has been conducting an evaluation of the main feedwater piping inside containment at Beaver Valley Power Station-Unit 1 due to the history of cracking that this piping has had in the vicinity of the steam generator nozzles. Initial concerns related to cracking in feedwater system piping were identified in NRC IE Bulletin No. 79-13. The short radius elbows on the Beaver Valley Power Station-Unit 1 feedwater piping immediately upstream of the steam generator nozzle have been replaced twice on loops B and C and three times on loop A due to inside wall cracks. The location and type of crack seemed to indicate that the steam generator nozzle was experiencing unexpected thermal cycling causing fatigue. During the seventh refueling outage (7R) in November 1989 it was also noted that the loop A and C feedwater piping inside containment was misaligned in the vicinity of the system's rupture restraints. This misalignment was most pronounced at the first rupture restraint upstream of the steam generator nozzle (FWR-38 and FWR-1, in loops A and C respectively). The affected piping was cut and reinstalled, and the rupture restraint gaps were reset to design conditions.

In order to help determine the probable cause(s) of the piping misalignment, the loop A feedwater piping inside containment was instrumented with thermocouples and lanyards prior to the plant restart after the 7R outage. Temperature and displacement data were recorded between 12-15-89 and 1-19-90, during which time the plant experienced several events including a reactor trip at twenty-nine percent power and a manual cooldown. Additional data were recorded between 10-6-90 and 10-13-90 following a manual cooldown.

A review of the recorded data indicated that the feedwater piping experienced significant global thermal stratification and that the nozzle was subjected to significant thermal cycling. Based on these data, thermal stratification was initially identified as a possible cause of the local nozzle cracking and the global piping deformation. The thermal stratification phenomenon results in the upper part of the feedwater pipe to be heated to a higher temperature than the lower part. The difference in the temperature and resulting differential thermal expansion between the top and bottom of the piping induces bending moments and significant deflections in the feedwater piping. This does not cause an overstress of the piping.

Additional evaluations utilizing the recorded data indicated that the monoball type vertical restraints may be locking-up during certain system conditions. This locking-up of the monoballs results in unanticipated system restraint on the feedwater piping system inside containment.

Recent thermal stratification analysis of the affected feedwater piping (loop A, B and C inside containment) was performed utilizing the recorded temperature and displacement data noted above. This analysis also addressed the impact resulting from the potential of locked-up feedwater system monoball supports. The loop B analysis considered the maximum theoretical potential thermal stratification (maximum main feedwater temperature - minimum auxiliary feedwater temperature). That analysis envelopes all probable thermal stratification profiles and no further action is required for loop B.

The thermal stratification profiles analyzed for loops A and C considered a temperature differential of 245 degrees F which corresponds to about 60 percent of the maximum theoretical potential thermal stratification. This temperature differential of 245 degrees F is based on the limited data obtained between 12-15-89 and 1-19-90 and between 10-6-90 and 10-13-90. The acceptability of these temperature profiles will be confirmed pending the results of a more comprehensive instrumentation program to be performed on the main feedwater system at Beaver Valley Power Station-Unit 1.

The above noted analysis concluded that all system pipe stress levels are within design basis allowable limits. Additionally, the revised pipe stress levels do not result in any new pipe break locations based on the criteria provided in NRC Mechanical Engineering Branch Technical Position 3-1 of Standard Review Plan 3.6.2. Beaver Valley Power Station-Unit 1 is not currently licensed to MEB 3-1. However, MEB 3-1 is the most current NRC criteria and use of it for interim plant operation is appropriate provided a future licensing change is performed to incorporate MEB 3-1.

An evaluation of the steam generator nozzles and containment penetrations concluded that the new loads are within design basis allowable limits.

Analysis of the feedwater system pipe supports has resulted in component stresses that exceed design basis allowable values. A further analysis of the affected pipe supports concluded that there is an acceptable design basis which provides a justification for continued operation (JCO) for Beaver Valley Power Station-Unit 1. Specific details of this support review along with future system recommendations are contained in the following paragraphs.

Since thermal stratification of the feedwater piping can occur during normal plant operation, the resulting loads from this load case are considered to be normal thermal loadings for pipe support design conditions. That is, thermal stratification loads are enveloped with normal thermal loadings and combined with deadload to determine normal support design loads. Specifically:

DL + THERMAL = NORMAL SUPPORT DESIGN LOAD

Where:	DL =	Deadload
	THERMAL =	Thermal including thermal stratification effects

This normal design load was compared to the existing design basis normal allowable to document component acceptability.

Additional support design loads which include the effects of occasional loadings (seismic and time history effects from fluid transients events) are also evaluated in determining support acceptability. The normal loading described above was combined with occasional loadings to determine the additional support design loads. Specifically:

DL + THERMAL + SRSS(OBEI, TH) + OBEA = UPSET SUPPORT DESIGN LOAD

DL + THERMAL + SRSS(DBEI, TH) = FAULTED SUPPORT DESIGN LOAD

Where:	OBEI =	Operational basis earthquake inertia
	OBEA =	Operational basis earthquake anchor movements
	TH =	Time history effects from fluid transient events
	DBEI =	Design basis earthquake inertia

APPENDIX D

These support design loads were compared to existing design basis upset and faulted allowables to document support acceptability. In certain instances where these allowable limits were exceeded, the criteria contained in ASME Section III, Appendix F, "Rules for Evaluation of Service Loading with Level D Service Limits", has been utilized to document support acceptability. This appendix provides alternate stress limits which can be considered when evaluating loads occurring during a plant faulted condition.

Although the rules for Appendix F apply to Level D Service Limits, the basis for using this appendix for evaluating the upset OBE loads or the faulted DBE loads is that in the event of a seismic occurrence of OBE or DBE magnitude, Beaver Valley Power Station-Unit 1 will be shut down and a feedwater system inspection will be performed. That is, only one potential upset seismic OBE event can occur during plant operation for this interim period. Furthermore, prior to any plant restart following this postulated seismic event, long-term (life of the plant) system modifications described later in this JCO will be implemented which will result in component stress levels being within existing design basis allowable limits. Based on this fact, the utilization of ASME Section III, Appendix F methodology and allowable limits is considered to be a reasonable approach to evaluate the feedwater pipe supports for this potential one-time seismic event at Beaver Valley Power Station-Unit 1.

The maximum support load from the upset and faulted load combinations previously defined was considered when utilizing the rules of ASME Section III, Appendix F. It should be noted that the upset load combination which includes occasional time history loads only still satisfies the existing design basis allowable limits. That is:

DL + THERMAL + TH < UPSET DESIGN BASIS ALLOWABLE

It is acknowledged that while Beaver Valley Power Station-Unit 1 is not licensed to ASME Section III and all of the requirements of the code are not met, the application of the principles of Appendix F are considered reasonable based on the following facts. ASME III and associated Appendix F is valid code, utilized in the design of several nuclear facilities. The criteria contained in Appendix F are based upon sound engineering principles and material behavior. The materials used at Beaver Valley Power Station-Unit 1, while not satisfying all of the requirements of ASME certification, are consistent with the materials specified by ASME III.

Typical allowable stress values contained in ASME Section III Appendix F which can be utilized for component evaluation are as follows:

Component Evaluation	Allowable Stress
* local stress at integral welded attachments	lesser of 3Sm or 2Sy
* support members in tension	lesser of 1.2Sy of 0.7Su
* support members in shear	lesser of 0.72Sy or 0.42Su
* bolts in tension	lesser of 1.0Sy or 0.7Su
* bolts in shear	lesser of 0.5Sy or 0.42Su

Where:
Sy = Yield stress
Su = Ultimate stress
Sm = Design stress intensity

APPENDIX D

The pipe support integral welded attachments were evaluated in accordance with Welding Research Council Bulletin 107 (WRC-107), except in certain instances where ASME Boiler and Pressure Vessel Code Case N-318 (CCN-318) was used. While CCN-318 is not currently included as part of the Beaver Valley Power Station-Unit 1 design basis, the application of CCN-318 is reasonable based on the following facts. CCN-318 is a valid code and has been widely used throughout the nuclear industry and it is applicable to all rectangular attachments conforming to certain geometric limitations.

Utilizing the methodologies described above, all pipe supports were evaluated and shown to be within acceptable limits. Based on these evaluations, it is concluded that the main feedwater piping system, including pipe supports, equipment nozzles and containment penetrations will be within acceptable limits during all postulated design basis events including the additional effects resulting from thermal stratification and additional loadings due to potentially locked-up monoball supports.

Since the pipe stress, pipe supports, equipment nozzles and containment penetrations have been judged to be acceptable, it can be concluded that the pressure boundary of the main feedwater system inside containment will be maintained. Furthermore, the noted reviews provide the basis for the justification for continued operation (JCO) for Beaver Valley Power Station-Unit 1.

Although the justification for continued operation has been concluded based on the noted evaluations, it is desirable and appropriate to perform additional engineering evaluations on the main feedwater system inside containment, considering potential system modifications, to provide long-term (life of the plant) qualification utilizing the existing design basis allowable limits.

These evaluations would provide an acceptable long-term design basis for all plant conditions including the effects due to thermal stratification noted herein. Engineering evaluations shall be performed in a timely manner to support the potential system modifications that may be required as part of this qualification. All modifications resulting from these evaluations will be implemented during the next planned outage at Beaver Valley Power Station-Unit 1.

The following actions are considered mandatory to provide long-term qualification and to confirm assumptions made in the interim plant analysis.

1) Develop and implement a complete instrumentation and data collection program for the loop A and C piping to verify maximum thermal stratification levels.
2) Perform a licensing change to incorporate MEB 3-1.
3) Perform a licensing change to incorporate ASME Boiler and Pressure Vessel Code Case N-318.
4) Perform field inspections to verify the minimum wall thickness of the loop A loop seal elbows.
5) Redesign pipe supports WFPD-R-3/4/11 to function as vertical supports. These supports should also be inspected to verify the as-installed configurations.
6) Pipe supports WFPD-HSS-201/202/203/204/205/206/212/212A should be inspected to verify snubber piston settings and available travel in both directions.
7) Implement an interim OBE limit.

APPENDIX E

10.5 CHRONOLOGY OF EVENTS WITH TEMPERATURE TIME ZONES

APPENDIX E

DATE	TIME	EVENT DESCRIPTION	ZONE
12-15-89	1750	Feedwater isolation. Auxiliary feedwater injection.	J
12-26-89	0055	Increasing reactor power level to 2% power.	A
12-26-89	0300	Regulating chemistry.	B
12-26-89	1325	Generator/turbine trip.	K
12-26-89	1800	Having difficulty maintaining turbine speed and governor valve control.	C
12-26-89	1900	Start 8 hour soak.	D*
12-27-89	0121	Reactor trip.	I
12-27-89	2000	Having difficulty controlling reactor temperature and steam generator levels with steam dumps.	E
12-27-89	2300	Begin 8 hour soak.	F*
12-28-89	1100	Turbine costdown following overspeed testing.	G
12-28-89	1235	Turbine synchronized to system.	H
01-19-90	1800	Manual cooldown.	L

NOTES: * Denotes zone associated with heatup of the plant from a refueling outage; associated with initial fuel conditioning.

APPENDIX F

10.6 CHRONOLOGY OF EVENTS WITH STRATIFICATION RESULTS

APPENDIX F

DATE	EVENT	RESULT
12-14-89	2 out of 3 steam generators high level. Feedwater isolation. Auxiliary feedwater injection.	Steady local stratification. Global stratification.
12-16-89	Erroneous reading on steam generator level transmitter. Feedwater isolation	N/A
12-18-89	Steam generator swell on opening of TV-MS-101. Feedwater isolation	N/A
12-18-89 to 12-25-89	Mode 3 operation.	Cyclic local stratification.
N/A 12-26-89	Commence reactor startup; Heatup through Mode 2 into Mode 1 (2%) power. Latch turbine. Turbine trip. Generator trip. Turbine reattached. Turbine trip.	Cyclic local stratification.
12-26-89	8 hour soak at 10% power.	Cyclic local stratification.
12-27-89	Reactor trip (29%) power. Feedwater isolation. Auxiliary feedwater injection of both motor driven pumps.	Cyclic local stratification. Global stratification.
12-27-89 to 12-28-89	8 hour soak at 10% power. Increase to 24% power. 30 hour soak at 30% power.	Cyclic local stratification.
01-19-90	Manual controlled cooldown Mode 1 to Mode 3 only. Returned to Mode 1.	Steady local stratification. Intrasystem global stratification (29%) power.

10-06-90	Manual controlled cooldown Mode 1 to Mode 3 only. Returned to Mode 1.	Steady local stratification. Intrasystem global stratification (29%) power.

APPENDIX G

10.7 ASME SECTION III APPENDIX F

1

IMAGE EVALUATION TEST TARGET (MT-3)

150mm

6"

It is acknowledged that Beaver Valley 1 is not licensed to ASME III and all of the criteria are not met. However, the use of Appendix F allowables for pipe support qualification for interim plant operation is considered acceptable based on the following reasons:

- ASME III is a valid code currently in use at several nuclear power facilities.
- The load combinations used in the pipe support analyses are consistent or more conservative than those specified in ASME III.
- The materials used at Beaver Valley 1 were procurred in accordance with ASTM specifications. While not satisfying all the requirements of ASME III certification, the materials used are similar with those specified in ASME III. Furthermore, the minimum yield stresses, ultimate stresses etc. used in the pipe support analyses are consistent with the specifications of ASME III.
- The criteria presented in Appendix F is based on sound engineering principles and material behavior. It is reasonable to expect that the materials used at Beaver Valley 1 behave as anticipated by Appendix F.
- Beaver Valley 1 was constructed and is maintained using good construction and inspection practices.

APPENDIX H

10.8 SUMMARY OF SUPPORT LOADINGS AND STRESSES EVALUATED BY ALTERNATE CRITERIA

Load Condition	NORMAL	UPSET A	UPSET B	FAULTED	INTERIM
Loads considered	DL, THER	DL, THER, OCC	DL, THER, OCC, OBET	DL, THER, OCC, DBEI	Max of Upset B or Faulted
Basis for allowables	AISC	AISC with 1/3 increase for occasional/seismic loads	AISC with 1/3 increase for occasional/seismic loads	AISC with 1/3 increase for occasional/seismic loads	ASME III, Appendix F
H-3 Member Shear Stress	8166 PSI $\leq .4S_Y$ 14400 PSI	18126 PSI $\leq$ 4/3 $.4S_Y$ 19200 PSI	20127 PSI > 4/3 $.4S_Y$ 19200 PSI N G	16423 PSI $\leq$ 4/3 $.4S_Y$ 19200 PSI	21027 PSI $\leq$ lesser of $.42S_U$ or $.72S_Y$ 25200 PSI
H-3 Bolt Shear	10000 PSI $\leq$ 10000PSI	10933 PSI $\leq$ 13333 PSI	18772 PSI > 13333 PSI N G	16171 PSI > 13333 PSI N G	18772 PSI $\leq$ lesser of $.42S_U$ or $.5S_Y$ 19800 PSI
H-3 Bolt Tension	9199 PSI $\leq$ 14020 PSI 28000 - $1.6f_V$	16546 PSI $\leq$ 21586 PSI $2(F_V^2 - f_V^2)^{1/2}$	18227 PSI > **** $2(F_V^2 - f_V^2)^{1/2}$ N G	15059 PSI > **** $2(F_V^2 - f_V^2)^{1/2}$ N G	18227 PSI $\leq$ lesser $.7S_U$ or S_Y 33000 PSI
H-3 Bolt Interaction	----------	----------	----------	----------	0.92 $\leq$ 1.00 $(f_V/F_V)^2 + (f_T/F_T)^2$

LOAD CONDITION	LOADS CONSIDERED	ALLOWABLE LOAD DESIGN BASIS	ALLOWABLE LOAD INTERIM	H-3	H-4
1	DL	1.0 S_h	---------	14701 PSI ≤ 15000 PSI	14819 PSI ≤ 15000 PSI
2A	DL, OCC	1.2 S_h	---------	15293 PSI ≤ 18000 PSI	155545PSI ≤ 18000 PSI
2B	DL, OBEI, OCC	1.2 S_h	2.4 S_h	20184 PSI > 18000 PSI 20184 PSI ≤ 36000 PSI	18076 PSI > 18000 PSI 18076 PSI ≤ 36000 PSI
3	DL, THER, OBEA	1.25 $(S_c + S_h)$	---------	36074 PSI ≤ 37500 PSI	35446 PSI ≤ 37500 PSI
4	DL, OCC	1.8 S_h	---------	15293 PSI ≤ 27000 PSI	15545 PSI ≤ 27000 PSI
5	DL, DBEI, OCC	2.4 S_h	---------	22334 PSI ≤ 36000 PSI	18874 PSI ≤ 36000 PSI