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OVERVIEW OF PIPING ISSUES AND TRENDS

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OVERVIEW OF PIPING ISSUES AND TRENDS

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ABSTRACT

A variety of failure mechanisms that have contributed to failures in nuclear reactor piping systems are discussed; these include general corrosion, intergranular stress corrosion, erosion-corrosion, mechanical fatigue, and thermal fatigue covering the spectrum from mixing-tee to stratification. Actions to minimize or eliminate these failure mechanisms are discussed where these actions are based on the experience amassed over the past three decades.

INTRODUCTION

This paper is a distillation of a Pressure Vessel Research Council (PVRC) WRC Bulletin[1a] recently completed that addresses a variety of piping failure mechanisms and suggests corrective actions. The intent of the WRC Bulletin was to examine the behavior of piping in nuclear power plants over the past 2-3 decades, review corrective actions and suggest approaches for the next generation of Advanced Light-Water Reactors. Portions dealing with failure mechanisms and corrective actions also appeared in the ASME Journal of Pressure Vessel Technology[1b].

The most common failure modes and mechanisms such as intergranular stress corrosion cracking, general corrosion, erosion-corrosion, thermal fatigue, and mechanical fatigue are addressed. Space limitations prevented discussion of microbiologically-induced corrosion and water hammer, both present in reference (1a).

The cited WRC Bulletin[1a] covering failure modes and mechanisms is the first of three planned bulletins. The second will address joining and optimization for nondestructive examination; the third will address modifications to current ASME Code design approaches covering fatigue and seismic loads.

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Two classifications of failure will be considered. The first, which is given the most emphasis, is catastrophic failure by double-ended guillotine break (DEGB), through major "fish mouth" failures, or by long splits. A characteristic of all three is the release of large volumes of water per unit time. The second classification covers cracks and leaks releasing limited quantities of water. These comply with the leak-before-break criteria.

An arbitrary separation by pipe size is made at one-inch NPS. Below one-inch ASME Section XI exempts pipes from examination on the assumption (not necessarily valid) that the high-pressure injection system, has sufficient makeup capability to handle a DEGB of a one-inch or smaller line. Lines larger than one-inch fall into the second category.

Corrosion other than erosion-corrosion has been a major contributor to plant outage even when gross failures have not occurred. Examples are intergranular stress corrosion where more than 1000 incidents have been reported in domestic reactors; other corrosion mechanisms are grouped to indicate their contribution. Finally, microbiologically-induced corrosion is handled separately because it may initiate from the inside or the outside of piping, usually, but not always, in buried lines.

Table 1 covers ASME Class 1, 2, 3 and balance-of-plant (BOP) piping failures by mechanism for pipes $\geq$2 inches in diameter. There have been no failures in Class 1 piping >2 inches in diameter; however, there have been Class 1 piping failures in smaller lines. Erosion-corrosion is the major failure mechanism in large lines, while vibratory fatigue is in small lines.

Table 2 provides an indication of systems subject to severe failures in piping $\geq$2 inches in diameter. The Achilles heel appears to be in the region including wet steam lines from the turbines to the condensers and continuing through the feedwater system. A majority of failures in larger lines occurs in this region.

Table 3 concentrates on safety systems with the exception of the low quality steam system. As can be seen the safety systems have suffered severe failures in the past.

CORROSION/STRESS CORROSION

Corrosion covers a spectrum of mechanisms included under chemical and electrochemical reactions between a metal and its environment. It covers uniform corrosion, pitting, localized corrosion, metallurgically-influenced corrosion, and both mechanically and environmentally assisted or induced degradation/cracking. Here erosion-corrosion, stress corrosion cracking both intergranular and transgranular, and microbiologically-induced corrosion are discussed separately, leaving other corrosion mechanisms as a catchall.

While these other corrosion mechanisms have been a major problem in nuclear power plants, the problem, to date, has been economic rather than safety-related for the catchall category.

TABLE 1 - FAILURES BY MECHANISM FOR PIPING ≥2-IN. D. - PERIOD 1964-91

MECHANISM	NO.	CL.1	CL.2/3	BOP
VIBRATORY FATIGUE	5	0	2	3
WATER HAMMER	9	0	4	5
THERMAL FATIGUE	0	0	0	0
MAINTENANCE ERROR	0	0	0	0
EROSION&CORROSION	(36)			
GENERAL/MIC	4	0	3	1
CAVITATION	2	0	2	0
EROSION-CORROSION	(30)			
SINGLE PHASE	11	0	8	3
WET STEAM	19	0	0	19
MISCELLANEOUS	(37)			
DESIGN/FAB. ERROR	4	0	2	2
OVER-P OP. ERROR	4	0	2	2
PUMP SEIZURE	1	0	0	1
GASKET FAILURE	2	0	1	21
CONSTRUCTION	4	0	4	0
VALVE PULLOUT	2	0	0	2
EXPANSION JOINTS	14	0	1	13
OTHER/UNKNOWN	5	0	3	2
VALVE RUPTURE	1	0	1	0
	87	0	33	54

FAILURES ARE DEFINED AS SEVERANCE, MAJOR SPLITS, FISH MOUTH.

CORROSION

Corrosion per se has not been a major problem in nuclear power plants. An initial concern with bulk corrosion led to consideration at the design stage which appeared to have minimized serious cases of corrosion. An extensive review of Licensee Event Reports (LERs) covering nearly 30 years revealed very few catastrophic failures due to any of these corrosion mechanisms. A few failures in small (<2-in. D.) lines due to corrosion (other than E/C, cavitation, MIC, SCC) have been reported such as the external corrosion of a buried line, corrosion in a fuel pool, and corrosion in seawater. Only one major failure of a large (6-in. D.) line was found. This failure was attributed to electrolytic corrosion of a buried liquid waste line.

Cracking/leaking incidents are much more common than severe failures. Failure mechanisms reviewed over a nineteen year period included stress corrosion (~200), thermal fatigue (~90), design/construction errors (45), water hammer (4), vibrational fatigue (~30), erosion-corrosion (25), corrosion/fatigue (~10), and unknown (~15). Erosion-corrosion was less than two percent of the cracks/leaks reported. These figures are biased because many such incidents occur in the balance-of-plant piping, and, often, are not reported via the LER route by utilities. The period cited for the above incidents was 1964-82.

TABLE 2 - FAILURES BY SYSTEM FOR PIPING $\geq$2-IN. D.
PERIOD 1964-91

CLASS 1	CLASS 2/3	BALANCE-OF-PLANT
NONE	2-LIQUID WASTE	19-CONDENSATE
	4-MAIN STEAM	1-HEATER DRAIN
	1-EMERG. SWS	1-ATM. STEAM DUMP
	4-RHR	14-STEAM
	11-FEEDWATER	1-FLOOR DRAIN
	1-CVCS	6-SERVICE WATER
	1-HPCI	1-SALT SWS
	2-AFW	5-REHEAT
	5-FIRE LINES	5-MOISTURE SEPARATOR
	1-CORE SPRAY	1-F.W./STEAM
		1-CONT. PURGE
	32	55

N.B. - PORTIONS OF MAIN STEAM, FEEDWATER, AUXILIARY FEEDWATER MAY BE EITHER CLASS 2 OR B.O.P.. F.W. AND A.F.W. ARBITRARILY WERE PLACED IN CLASS 2, RECOGNIZING THAT SEVERAL FAILURES WERE IN B.O.P. REGION. MAIN STEAM FAILURES, WHEN KNOWN TO BE CLASS 2, WERE SO IDENTIFIED.

Nuclear piping systems may be susceptible to attack by corrosion mechanisms other than those covered in this report; namely, galvanic and stray-current, crevice, pitting, corrosion-fatigue, fretting and hydrogen attack.[2,3]

Major attention is given to the light-water reactors where piping materials include carbon steels, low alloy ferritic steels, austenitic stainless steels and high nickel alloys such as Inconel-600 used in safe-ends. A subjective judgment concerning the susceptibility of piping to the cited corrosion mechanisms indicates that several mechanisms are probable, most result in economic penalties rather than catastrophic failures with safety consequences. Mechanisms and systems with a susceptibility for severe failure include galvanic attack of buried lines, particularly when tied to MIC. Corrosion-fatigue can lead to failed lines; this is covered under thermal fatigue. Both pitting and crevice corrosion tend to be detected by leaks before major failure.

Crevice corrosion can be much more severe than pitting corrosion. If a concentration cell can be established due to an oxygen gradient, attack will occur. Failure of condenser tubes cooled with seawater is an example of crevice corrosion. This can occur with both ferritic and austenitic alloys.

TABLE 3 - SAFETY SYSTEM FAILURES IN PIPE $\geq$2-IN. DIAMETER
PERIOD 1964-91

MECHANISMS

SYSTEM	FABRICATION & DESIGN	WATER HAMMER	EROSION-SINGLE PHASE	CORROSION WET STEAM	VIBRATORY FATIGUE	OTHER	TOTAL
STEAM	3	2		23*	1	1	30
FW/AFW		3	5			1	9
RHR		3					3
CVCS			1				1
HPCI	1				1		2
ECCS						1	1
TOTALS	4	8	6	23	2	3	46

*MOSTLY BALANCE-OF-PLANT NOT SAFETY SYSTEMS
FAILURES DEFINED AS SEVERANCE, MAJOR SPLIT, OR FISH MOUTH

Corrective Actions

Anodic or cathodic protection, depending on the piping material and environment, is suggested for buried lines. In a liquid environment such as the water in a pipe, where pitting or other corrosion attack is a problem, the corrective actions are to keep surfaces clean, avoid stagnant solutions (sometimes difficult), avoid galvanic couples, minimize rupture of coatings and avoid crevices.

Reinforced concrete used to form a culvert to surround pipes represents a potential problem, particularly if salt is added to accelerate curing. The gap between pipe and concrete can be a trap for water as well as contaminants such as salt in plants near the sea or on tidal estuaries. These contaminants can leach the concrete and attack the external surface of the pipe. Removal of the salts or cathodic protection can minimize attack of concrete and piping.

STRESS CORROSION

Stress corrosion in nuclear power plants usually occurs as intergranular stress corrosion cracking (IGSCC) in alloys such as the austenitic stainless steels and the higher nickel alloys. The first of three factors contributing to IGSCC is sensitization due to precipitation of carbides at grain boundaries in the heat-affected zone due to the welding heat input; alternatively any wrought austenitic stainless steel containing sufficient carbon that is welded to ferritic vessels as safe-ends, then the vessel is stress-relieved, will result in furnace sensitizing the safe-ends. The second ingredient is stress; residual stresses generated by the welding operation are sufficiently high to initiate IGSCC. Again, external loads can lead to stresses high enough for initiation. The third ingredient is the environment; while many chemicals can cause SCC, the common one, particularly in boiling water reactors, is oxygen in the coolant. Oxygen levels in the several ppm range are sufficient to lead to IGSCC, provided the other factors of sensitization and stress are present. Summarizing, IGSCC can occur if all three factors: (1) sensitization; (2) stress; (3) presence of oxygen or other chemical initiators, are present.

A reasonable estimate of reported incidents of IGSCC is in excess of 1000 in the domestic nuclear power plants and twice that number worldwide. IGSCC generally is detected by small leaks or with sensitive ultrasonics; most cracks do not approach instability dimensions; however, there have been at least two "near misses" that are discussed in the following paragraphs.

the Duane Arnold Recirculations-Inlet Nozzle Safe End including location of a repair weld and a representation of IGSCC in the leaking recirculation inlet-nozzle safe end. The nozzle is approximately 10 inches in diameter. The repair weld occurred because of an error in the fabrication drawing that resulted in the machining of a groove in the outer surface of all eight safe ends. Repair consisted of filling with weld metal. Since the safe ends were attached to the vessel nozzles prior to stress relief, they underwent two $595 \pm 15\,°C$ stress-relief treatments. The thermal sleeve that was installed to direct coolant flow into the vessel. It also resulted in a long, narrow crevice ending at the tip of the attachment weld. This crevice led to a stagnant chemical environment conducive to IGSCC. A severe resin spill produced an acid sulfate that was trapped in the crevice as confirmed by the presence of sulphur and low pH.[4]

This failure was a classic case of multiplicative probability where a prior estimate would have given a very low probability, probably less than E-7. Inconel-600 resists corrosion by the BWR environment but not sulfur complexed ions. The weld metal created a uniform residual stress field so the IGSCC progressed to 360° around the circumference, then through wall. Fortunately the IGSCC penetrated 100% through wall on one safeend and the leak was detected.

Figure 1 represents the one leaking safe end. Note the 360° circumferential crack that is through-wall in one section and 50-75% through-wall over most of the remaining circumference. While Figure 1 illustrates the leaker, the other seven safe ends were cracked almost completely around the circumference. Duane Arnold and Nine Mile Point represent the two cases of SCC in nuclear power plants that could have led to a double-ended guillotine break (DEGB). Therefore, the message here is to avoid crevices (possibly by not installing thermal sleeves, recognizing that there is a tradeoff between systems with and without thermal sleeves. While their absence should minimize the trapping of deleterious ions that may lead to stress corrosion, the system without thermal sleeves may be more sensitive to thermal fatigue.) and conduct in service inspection in conformance with NUREG-0313.

<u>PWRS</u>

The incidents of primary water stress corrosion cracking in PWRs appear to be increasing. In fact the situation probably is worse than in BWRs, particularly with regard to Inconel-600 failures. Cases in steam generators, in austenitic stainless steels, and Inconels have been known for years. Now it is occurring in safe-ends and piping at very low oxygen levels. Secondary-side water chemistry must be controlled to prevent SCC in PWRs.

A specific instance of the sensitivity of Inconel 600 to SCC was reported in the French PWRs during late 1991 and early 1992. Axial cracking and leaking occurred at Bugey-3; two other plants reported cracking. The leak was detected during a 10-year hydrostatic test at $1.33P_{op}$ which is a much higher hydrostatic pressure than used in domestic reactors. Obviously the crack was very tight because the leak rate was only one liter/hr.

This may be a case of Coriou cracking in the primary coolant. Dr. Coriou of France has investigated stress corrosion cracking in the austenitic stainless steels and the nickel alloys for several years; he discovered that these alloys are susceptible to cracking in the primary coolant of pressurized water reactors. All cracks occurred in the same place on the vessel head on the periphery where the head curvature is greatest. The dissymmetric welds on both sides of the penetration led to very high stresses. These incidents probably represent a generic problem that may affect domestic reactors. The three critical factors are high residual stress, higher than average head temperatures (~315°C), plus long operating times.

Corrective action is to replace the heads and use Inconel 690 for the sleeves; another possibility is to reduce the head temperature somewhat. If head temperatures are at or below 300°C, shot peening to reduce the high tensile stresses and replace them with compressive stresses may be sufficient to eliminate the problem.

BWRS

- The corrective actions cited in this study appear to have led to a substantial reduction of IGSCC. One can be cautiously optimistic that extensive IGSCC should not occur. However, so long as the combined conditions of stress, sensitization, and oxygen exist, we should expect to see IGSCC.

- Hydrogen water treatment controls the oxygen and should limit IGSCC. Whether other problems arise is yet to be determined. A possible problem is erosion-corrosion in the carbon steel lines if the oxygen is low.

- In most cases, severe circumferential SCC should lead to detectable leakage so that leak-before-break can be identified; however, there can be special cases where the crack size approaches instability. A rule of thumb is that a through-wall crack of 30% of the circumference is stable. This should be detectable by leakage.

- IGSCC of austenitic stainless steels can occur in all pipe sizes from smallest to largest, especially when stress, sensitization, and oxygen are all present.

Although we have seen considerable progress in controlling and mitigating IGSCC in nuclear plants, problems still exist.

Recommendations

- Eliminate, where feasible, non-flow conditions in branch lines by operating with shutoff valves in open mode (e.g., valve in by-pass lines).

- Eliminate as many non-flow and low-flow lines as possible.

- Within limits of good design practice and serviceability during operation, minimize the extent of the reactor coolant pressure boundary by methods such as placing valves as close to the reactor vessel as possible. Particularly, non-isolable piping in the reactor coolant pressure boundary should be kept to an absolute minimum.

- To assist in reducing the incidence of SCC in PWR secondary systems, contaminants leading to SCC should be reduced to the extent possible by control in the fluid reservoirs, periodic flushing, and rinsing of surfaces.

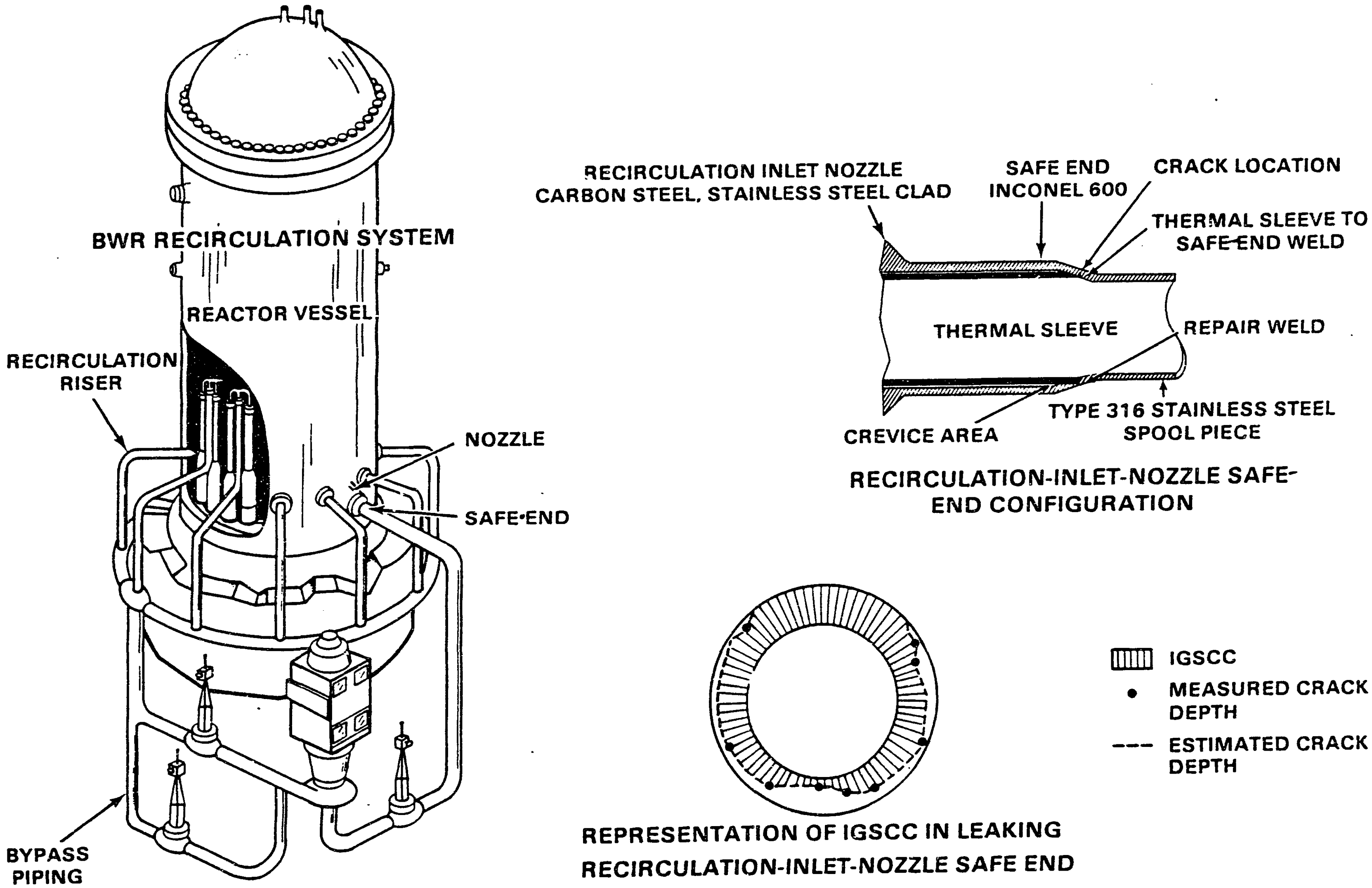

Figure 1 - Example of Severe Intergranular Stress Corrosion Cracking in Inconel-600 Safe End

- For future plants or for replacement of existing piping systems, the material, design of pipe joints, and accessibility from both sides of the weld should be optimized for UT examinations; this requirement should be mandatory for all components with the exception of existing items such as pumps, valves, and vessels in older plants. Additionally, the uninspectable joints should be subjected to IHSI.

- Because the UT examiner is one of the more erratic inspection variables, it is recommended that human factors research be performed to reduce the possibility of human error.

- The recommendation for a limit on acceptable crack length is primarily a result of the lack of confidencein ultrasonic depth sizing capabilities. In this respect, the fracture mechanics calculations presented in this report demonstrate that there are acceptable margins against fracture for relatively long, deep surface cracks. Demonstration of reliable sizing of the part-through flaw depth would most likely allow relaxation of the limits on crack length.

- Although low-carbon stainless steels with nitrogen additions have been successfully fabricated and welded in Japan and Europe, U.S. experience with these materials is limited. It appears that greater care must be exercised in the control of composition and fabrication variables to limit cracking during hot forming or welding.

- Induction-Heating-Stress-Improvement is considered to be a more effective mitigating action for IGSCC than Heat-Sink-Welding and Last-Pass-Heat-Sink-Welding because more data are available to demonstrate that the IHSI does produce a favorable residual stress state. All the residual stress improvement remedies are considered to be more effective when applied to weldments with no reported cracking.

- Care must be exercised in the handling and storage of wrought austenitic stainless steels because of their sensitivity to chloride ions; these ions can lead to transgranular stress corrosion during storage, or cause IGSCC in sensitized regions of the pipe; even trace amounts of chlorides are sufficient to cause SCC.

- Leak detection is a good indication of through-wall cracks before they approach instability. In particularly tight cracks, however, the process may be marginal.

- Acoustic emission will detect small leaks and may detect cracking; however, it is dependent on where transducers are located and how many are used.

- Safe-ends, reactor vessel head sleeve connections, and other high nickel components to a PWR primary system should be fabricated of a material more resistant to SCC than Inconel-600; Inconel-690 is an option.

EROSION-CORROSION AND CAVITATION DAMAGE

Ferritic piping under certain conditions in nuclear power plants, and, in some instances, fossil power plants can suffer severe wall thinning and gross failure. Nuclear plants may fail by either single-phase or wet-steam erosion-corrosion while fossil plant erosion-corrosion failures primarily are limited to wet steam because of the adherent magnetite film when alloys such as P22 are used in the single phase systems. An example of each failure mechanism in nuclear plants follows:

Surry-2 suffered a severe failure due to single-phase erosion-corrosion of the feedwater line on December 9, 1986[5]. A steam valve closure increased the line pressure about 20%; this was sufficient to fail a 90° elbow in the balance-of-plant (BOP) portion of the 18-inch feedwater line. A section of pipe about 2-feet by 3-feet blew out, resulting in a complete separation. The reaction forces moved the pipe about 6 feet. Four of eight contractor employees who were in the area subsequently died of severe burns. While the failure occurred in the BOP, a number of single-phase erosion-corrosion failures have occurred in Class-2 safety systems.

On June 28, 1982 Oconee-2 experienced a severe rupture of a 24-inch steam extraction line[6] Two personnel suffered burns requiring overnight hospitalization. The rupture occurred in the outside radius of a 0.375-inch thick 90° elbow where the 24-inch steam extraction line branched off a 42-inch high pressure turbine exhaust line. The rupture size was about 4-ft^2 (approximately 2-feet by 2 feet). The failure was downstream of the main steam stop valves so the turbine trip isolated the steam supply to the extraction line. The escaping steam physically destroyed a motor control center and several non-safety-related instruments. An interesting aspect was that ultrasonic thickness testing on the elbow in March 1982 revealed significant erosion thinning, but the elbow was considered serviceable because the thinnest area recorded was 0.170-inch thick. Micrometer measurements after the rupture revealed a thickness of 0.017-inch. It was suspected that the UT measurement did not identify the thinnest area. Other UT measurements on Oconee-1 revealed thinning to 0.100-inch from 0.375-inch, well below minimum wall thickness.

NRC Information Notice 92-35[7], dated May 6, 1992 reported a, "Higher than Predicted Erosion/Corrosion in Unisolable Reactor Coolant Pressure Boundary Piping inside Containment at a Boiling Water Reactor". This occurred at the Susquehenna Unit 1 in a main feedwater pipe inside containment, presumably in an A-106 pipe. This plant has been operating since 1982. The component of concern was a 20 inch by 12 inch reducing tee. The nominal pipe wall thickness was about 0.699 inch. A thickness measurement in the pipe attached to the 12 inch tee section had been 0.619 inch at the previous outage about 18 months ago. When measured in the 1992 outage, the same location was 0.521 inch and about two inches away it was 0.482 inch. A calculated minimum wall at that location was 0.440 inch. The issue of concern was the rate. Previous experience and models indicated an erosion wear rate of no more than 0.085 inch per cycle rather than the measured wear rate of greater than 0.100 inch per cycle.

The concern was the location inside containment and the fact that that section was unisolable. This represents a break between a BWR feedwater nozzle and an isolation valve. Based on the flow direction ;in the 20 inch line, one would anticipate erosion/corrosion attack in the wall of the 12 inch tee leg or the attached pipe on the side corresponding to the flow direction in the 20 inch line. This, in fact, was where it occurred, representing a region of high turbulence.

Cavitation damage is the degradation of a solid body resulting from its exposure to cavitation. This may include loss of material, surface deformation, or changes in properties. Cavitation, usually related to pumps or valves in the case of piping, is the formation and instantaneous collapse of innumerable tiny voids or cavities within a liquid subjected to rapid and intense pressure changes. At times the term cavitation corrosion is used when both processes occur concurrently. Cavitation often is closely related to erosion-corrosion.

Pump impellers are the usual source of cavitation, although any condition where a surface is in contact with a high-velocity liquid subject to changes in pressure can lead to cavitation damage.

In appearance cavitation damage is similar to pitting corrosion except the pit surfaces tend to be rougher. The favored mechanism is a combination of corrosion and mechanical effects where the collapsing vapor bubbles mechanically destroy the protective surface films, exposing these fresh surfaces to corrosion.

In nuclear plants, or any facility where the appropriate conditions exist for cavitation, carbon steels exposed to water velocities of 10-30 ft/sec have corrosion rates $>>$100-times as great as austenitic stainless steels; however, severe cavitation conditions will lead to attack of alloyed steels, including austenitic stainless steels.

A number of nuclear power plants have reported severe failures of small lines at pumps with the cited cause being cavitation. In larger pipes it is probable that some of the single-phase erosion-corrosion failures where flow velocities exceeded 20 ft/sec had cavitation as a major contributor to failure.

Single-Phase Erosion-Corrosion

Significant parameters affecting single-phase erosion-corrosion are the chemical composition of the pressure boundary material, pH level, temperature, oxygen content of the coolant, coolant flow linear velocity and turbulence.

Wall thinning due to single-phase erosion-corrosion is a time-dependent phenomenon. Under extreme conditions with plain carbon steel piping, severe attack may occur in a relatively short time. With more benign conditions and/or higher alloy levels in the pressure boundary material, the attack may be delayed many years or may not occur during the plant life. Systems in nuclear power plants that are particularly vulnerable are the main feedwater and the steam generator letdown lines. At times pickled pipe has been installed which shortens the time for erosion-corrosion to occur.

Erosion-corrosion is caused by a complicated interplay of a number of parameters. A large body of experimental work has identified several key variables that influence the rate of attack. These variables are listed in Table 4 with an indication of how they impact the material loss behavior.

The complexity of these variables and their interrelation are such that a mathematical model which considers all of the variables is required to make erosion-corrosion predictions with any accuracy. This predictive capability helps avoid wholesale, random and nonproductive inspection efforts.

The CHEC™ (CHEXAL-HOROWITZ-EROSION-CORROSION) computer program[8a] was developed by EPRI to meet this industry need. The general formulation of the model used in CHEC is a series of factors which, when multiplied together, yield the predicted erosion-corrosion rate. Since some of the factors are interrelated, the model is not linear.

TABLE 4 - EFFECT OF VARIABLES ON EROSION-CORROSION RATE

EROSION-CORROSION RATE INCREASES FOR

VARIABLE	IF VARIABLE IS
Fluid Velocity	Higher
Fluid pH Level	Lower
Fluid Oxygen Content	Lower
Fluid Temperature	250-400°F (120-205°C)
Component Geometry	Such as to Create more Turbulence
Component Chromium Content	Lower
Component Copper Content	Lower
Component Molybdenum Content	Lower

Wet-Steam Erosion-Corrosion

The CHECMATE™ computer program, also developed by EPRI[8b] models wet-steam erosion-corrosion. It has been used to select piping sections for non-destructive examination.

In nuclear power plants essentially no safety-related systems suffer from wet-steam erosion-corrosion. Generally, the systems affected are in the balance-of-plant, particularly near the large steam turbine. A possible, but improbable, system to be attacked would be the steam line before it joins the turbine. While such attack may not be safety-related, it certainly represents a severe economic penalty for both fossil and nuclear power plants, particularly is there is injury or loss of life to personnel. In some instances the release of steam has activated or challenged various safety systems.

The usual location of severe attack is the extrados of elbows where severe thinning can lead to gross fishmouth failures. Tiger striping may occur in straight sections of pipe; however, the attack usually is limited. Downstream of flow control and level control valves wet-steam erosion-corrosion has led to guillotine breaks.

A special and common case of wet steam attack is where water droplets at high velocities impinge on metal surfaces. Elbows are particularly susceptible. The usual corrective action is to increase the alloy content in the elbows. In fact, some utilities replace attacked elbows with austenitic stainless steel elbows which eliminates the problem.

Mitigation Options

Depending upon the extent of wall thinning, utilities are applying several options to rectify both the single-phase and the wet-steam erosion-problems. These include:

- Implementing a water chemistry change;
- Changing piping design/layout to improve flow geometries;
- Repairing or replacing with more resistant materials;
- Removing moisture from the steam.

Water chemistry changes are attractive in that they offer a means of prolonging the life of existing piping. Two water chemistry variables, other than temperature, have been shown to have strong effects on the rate of erosion-corrosion; namely, pH level and dissolved oxygen content. An example of serendipity is in the replacement of condenser tubes from the usual copper alloy to titanium. With the copper alloys a pH above 9 (8.8-9.2) leads to accelerated attack of the condenser tubes. The use of morpholine rather than ammonia as the pH control additive also reduces the rate of erosion-corrosion. With titanium a pH higher than 9 poses no problems; a substantial gain is possible above a pH of 9; namely, 9.3 to 9.6. The titanium tube approach has been used in nuclear PWR's to date. More uses of titanium for condenser tubes is expected in the future.

BWR water chemistry differs significantly from that of a PWR. First, chemical additives are not employed routinely. Second, significant oxygen levels exist in the condensate, feedwater, and steam trains. Operation near the 50 ppb oxygen upper limit of the indicated achievable range could reduce the probability of flow-assisted corrosion in single-phase regions.

Replacement of carbon steel piping, usually A-106, with low alloy piping is successful in mitigating erosion-corrosion. Current data suggest that an alloy containing 1/2 to 1% chromium would provide adequate resistance in single-phase systems. Since fossil plants use alloys exceeding these levels, it is understandable why single-phase erosion-corrosion is not a problem in such plants. Two low alloy steels which are available in a variety of sizes and for which there has been considerable fossil power plant experience are 1-1/4 Cr-1/2 Mo (P11 grade) and 2-1/4 Cr-1 Mo (P22 grade). As these low alloy steels have almost the same mechanical properties at the operating temperatures of interest, replacement piping of this material can be installed with the same geometry and unit weight as the original carbon steel components. Additionally, the thermal stresses and nozzle loadings are of little consequence due to the similarities in the coefficients of thermal expansion. As a result, the substitution of either of these grades is generally straightforward, and any design analysis should be minimal for the same configuration. One disadvantage is that both the P11 and P22 Grades require special considerations for welding, especially preheat and postweld heat treatment. However, these considerations are well documented and represent standard practice in the industry.

Austenitic steels also have excellent resistance to erosion-corrosion both single-phase and wet-steam. Low carbon grades are preferable because of better intergranular stress corrosion cracking (IGSCC) resistance. The candidate materials are 304L, 316L, and 347L, or the 304NG and 316NG Nuclear Grades. These materials are readily available and do not require preheat or postweld heat treatment. The disadvantages of austenitic stainless steels are that piping reanalysis is required due to a higher thermal coefficient of expansion (1.4 x carbon steel); the bimetallic welds need special attention; susceptibility to chloride stress corrosion raises concern over the chloride contaminants in thermal insulation; and they are more expensive.

RECOMMENDATIONS

- Fluid velocity should be relatively low (10-15 feet/sec) to minimize erosion/corrosion.
- A pH above 9.0 will reduce tendency for E/C; this depends on material in condenser tubes; if copper based, higher pH is difficult.
- Oxygen content should be at least 50 ppb to minimize E/C.
- The worst operating temperature is 250-400°F (120-205°C).
- Component geometry should be selected to minimize turbulence.
- Increasing chromium, copper and molybdenum in the pipe reduces E/C.

FATIGUE

Fatigue is the material damage caused by cyclic loadings on a structural component. Fatigue damage in nuclear piping components is a function of the following variables:

- Thermal Loadings
- Mechanical Loadings
- Material Composition
- Size and Geometry of Component
- Surface Condition
- Operating Environment

There are a number of industry actions in place or being planned to address the issues identified by the lessons-learned experience. These include the following:

- EPRI and utility owners group studies on thermal stratification, cycling and striping. EPRI has a new research initiative to develop criteria and methods to assist operating utilities in managing and controlling fatigue.
- Actions by ASME Section XI Task Group on Operating Plant Fatigue to develop code rules to evaluate fatigue issues arising from differences between design assumptions and the operating practice. A whitepaper report has been published as a result of the study (EPRI Report TR-100252). Also, PVRC is considering publishing it as a WRC Bulletin.
- Section XI subgroup on Flaw Evaluation has actions to improve crack-growth-rate curves

to account for various environmental effects on FCG.

- PVRC technical review committee (on environmental effect on fatigue life) plans to develop recommendations to ASME Boiler Code and Standards Committee.

- PVRC committee (on Shells and Ligaments) studies aimed at understanding the effects of initiation, propagation and fracture on fatigue.

Based on the brief review of the design and analysis practice, operating experience and ongoing research and development, the following observations and recommendations are made:

- Thermal stratification, cycling and striping loads should be included in the design specification.

- Revisions should be made to appropriate sections of piping code to provide improved methods and criteria for designing vent and drain lines.

- ASME Section XI and PVRC activities are in place to address the issues related to fatigue criteria and methods. Progress by these bodies should be followed to assure all issues are addressed.

- Long term specimen and components testing is needed to better understand corrosion-fatigue phenomena and to develop design and operational guidelines to minimize failures caused by this phenomena.

MECHANICAL/VIBRATORY FATIGUE

Most mechanical fatigue failures in piping are a result of vibrations which are not uncommon occurrences. Virtually every piping system which contains a flowing fluid exhibits some degree of vibration. The cause of the vibration can differ. Pressure pulsations and movement from attached rotating equipment are amongst the most common causes of vibration in piping systems.

The ASME Boiler & Pressure Vessel Code provides very general statements regarding control of vibration in piping systems. However, the ASME Operations & Maintenance Standards and Guides, OM-3, provides specific requirements for evaluating the severity and possible consequences from steady state transient vibration conditions.

Failures due to Vibration

An AEOD report[9] cites several failures in small diameter piping in the period 1981-82. Most of the failures were caused by vibration. The first conclusion in the report is quite revealing, being closely coupled to the lead-in Section discussing vibration; this conclusion is quoted below:

"(1) Most of the small pipe leaks appear related to unanticipated vibration-induced fatigue. The source of such vibrations seems to result from operation of pumps, valves, orifices, or flow-induced phenomena, but apparently the vibration spectrum present during operation was not part of the design or functional specifications for the piping system. Further, classification as a problem worthy of action seems to depend upon development of a leak (possibly repeated leaks) rather than recognition or observation of unusual vibration by itself. Since these problems are still occurring at several plants after several years of service, this situation with vibration of small lines appears to be both a generic and a current problem".

A recent failure[10] confirms the potential severity of small line severance. A 3/4-inch diameter instrument line, a part of the reactor vessel level indication system, separated from a compression fitting next to a 3/4-inch flow restriction valve. This unisolable leak released 87000 gallons of reactor coolant at a maximum rate of 130 gpm.

While compression fittings simplify installation, their failure can be very expensive. In the opinion of the PVRC Piping Review Committee, they should not be permitted in critical installations, particularly when attached to Class-1 piping.

THERMAL FATIGUE

Thermal fatigue has been relatively common in nuclear power plant piping and nozzles in the past two to three decades. Some generic thermal fatigue issues have been resolved shortly after they surfaced; others continue to be a problem.

The two thermal fatigue initiators have been stratification of hot and cold layers of coolant and the classic mixing-tee problem. Both have led to a large number of cracking and limited leakage incidents; however, there have not been the severe failures such as caused by erosion-corrosion, or water hammer. Some of the incidents of thermal fatigue can be characterized as near misses because some crack lengths approached instability conditions.

While mixing-tee thermal fatigue can be classified as an example of stratified flow, conditions where hot and cold streams mix at finite velocities, are arbitrarily defined as "mixing-tee". Stratification is defined where there is virtually no flow and hot water layers over the cold. A special subset is where there are low leak-through rates in closed valves (< 1 gpm). The valve leak-through represents a quasi-equilibrium where the hot-cold interface leads to cracking. In some cases of stratification there can be intermittent turbulent mixing due to brief jogging of pumps. This condition may represent a very severe transient and can lead to low-cycle fatigue failure.

Mixing-Tee Failures

Case History

Classical cases of mixing-tee failure occurred in Swedish BWR's during 1980[11]. Three of the plants had thermal fatigue cracks that were detected with an ultrasonic examination of the 304ss lines. The feedwater system (180°C), auxiliary feedwater system (30°C) and the shutdown cooling system (270°C) come together at the tee. Cracking occurred in the feedwater line and shutdown cooling systems. Cracked regions were 200-300mm (8-10-in.) long and extended about 180° around the pipes. Cracks were both longitudinal and circumferential with lengths of 10-100mm (0.4 to 4-in.) and depths of 2-10mm (<0.4-in.). The thermal sleeves present also cracked.

Specific Cause and Corrective Action

Intermittent mixing of three coolant streams at grossly different temperatures virtually guaranteed thermal fatigue. Corrective action was to install a different geometry thermal sleeve where thorough mixing occurred prior to contacting the pipe wall. One proposed design was quite large and very flexible so there was a definite possibility of fatigue failure of the sleeve due to flow-induced vibrations. A major plant redesign would be needed if the thermal fatigue problem were to be eliminated.

THERMAL STRATIFICATION

Turbulence in piping systems, under normal flow conditions, creates sufficient mixing of the fluid which results in a uniform temperature profile. Under certain circumstances, a single-phase fluid can separate into two streams due to differences in density. This phenomenon is called thermal stratification.

Thermal stratification is a phenomenon where a fluid at two different temperatures, under low flow conditions, separates into two streams. The stream at higher temperature flows over the lower temperature stream. The stability of the separation is dependent upon the differences in temperature and velocity of the streams. Greater temperature differences and lower velocities result in a more stable stratification condition.

Striping Phenomenon

The two fluid streams which are at different temperatures are separated by a transition layer containing a temperature gradient. This layer oscillates and moves vertically. The vertical location of the transition layer is dependent upon the temperature differential between the two regions and the flow rate. Even under relatively constant temperature and flow conditions, the layer will oscillate. This phenomenon is called "striping".

This oscillation causes alternating heating and cooling of a limited region of the pipe. Depending on the magnitude and frequency of oscillation and temperature gradient within the transition layer, additional stresses will be induced in the pipe.

Structural Effects

The higher temperature fluid will cause greater strain in the pipe in its vicinity than will be induced in the vicinity of the colder fluid. This difference in strain will cause bending of the pipe, typically in the vertical plane. This vertical bending will create unanticipated forces, moments and displacements. The additional moments will create higher stresses in the pipe and at the end connections. The unanticipated displacements could result in unintentional restraint of the piping system (e.g., gaps on restraints could close and snubbers could stroke out). Due to the intermittent nature of this phenomenon, fatigue cumulative usage factor will increase. Both bending and striping will contribute to fatigue degradation. However, actual experience and analyses indicate that the striping phenomenon typically does not contribute significantly to the cumulative usage factor since the thermal gradient in the transition layer is not a "step function" and the location of the transition layer varies with time, flow rate and temperature.

The alternating heating and cooling of the pipe usually affects only the inside surface layer of the pipe.

Thermal Stratification-Valve Leakage

Case History

Unisolable leaks due to valve leak-through occurred in the period late 1987-88. Farley-2[12] developed a leaking crack with 0.6 gpm rate in an unisolable section of a 6-inch emergency core cooling system line attached to the reactor cooling system cold leg. Figure 2 illustrates the location of the crack and the temperature differences at top and bottom of the pipe with and without leakage. The crack occurred at the underside of the pipe and covered 120°. The cause was intermittent leak-through of a globe valve at the seat. This leak caused the ECCS check valve in Figure 2 to chatter so cold water was introduced. The charging pumps being on exacerbated the situation.

Specific Causes and Corrective Actions

Farley-2 failure was due to high-cycle thermal fatigue caused by leakage of cold water through the globe valve at a pressure sufficient to open the check valve. Corrective action consisted of installing monitoring equipment. In addition EPRI has developed a TASCS Program (Thermal Stratification Cycling and Striping) to permit evaluation of valve leakage. At Farley with the charging pumps running and the valve leaking the thermal stratification plus temperature fluctuation led to peak-to-peak amplitudes to 70°F with periods of 2 and 20 minutes.

Stratification-Leaking/Cracking

In some PWR designs, the Auxiliary Feedwater (AFW) System provides fluid to the Steam Generators via the Main Feedwater (MFW) piping. The MFW piping is sized to deliver flow at high temperature and velocity during full power operation. The AFW fluid is delivered at

lower temperatures and flow rates. Under low power operation and power ascension, the AFW system is required to supply feedwater to the Steam Generators through the MFW line. There is approximately a 3 to 1 ratio in pipe size between the MFW and AFW systems. Therefore, the AFW velocity in the MFW pipe is significantly reduced. Again this low velocity and temperature difference makes this piping susceptible to thermal stratification.

Other systems in which thermal stratification has been reported are Pressurizer Spray System, Reactor Core Isolation Cooling System (RCIC) and Reactor Water Cleanup System (RWCU). As pointed out previously, any system that contains fluid at different temperatures flowing at low velocities, in the absence of turbulence, is potentially susceptible to the thermal stratification phenomenon.

Farley 2 Temperature Data

	With Leakage	Without Leakage
Top of Pipe	226°C	257°C
Bottom of Pipe	107°C	254°C

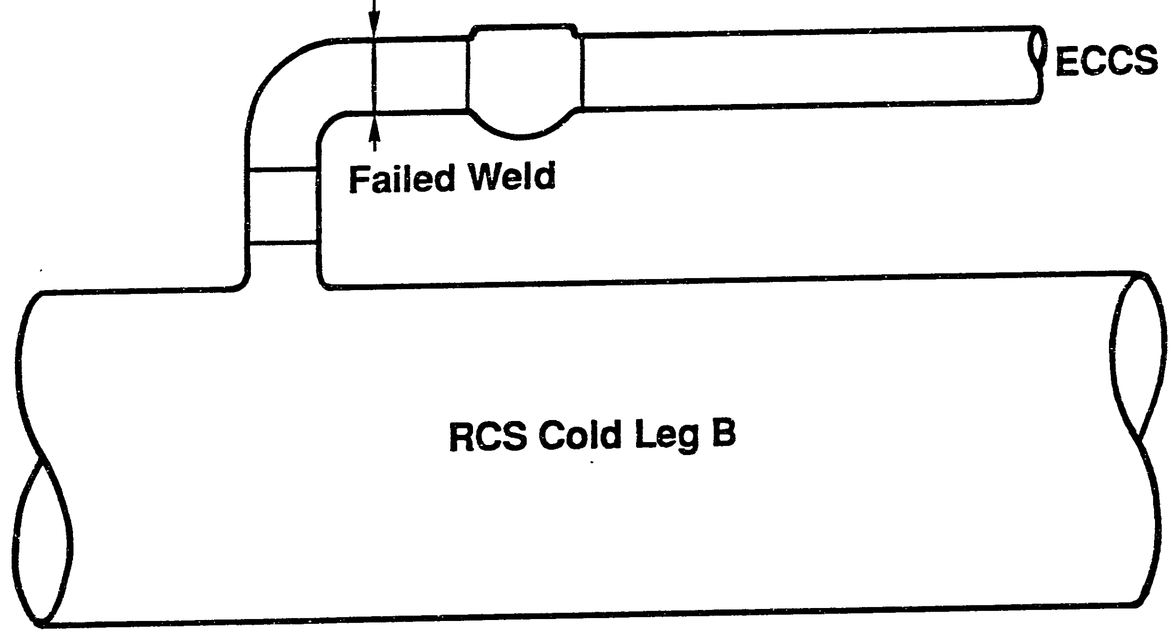

Figure 2 An Example if Thermal Fatigue Cracking due to Leak-Through of a Globe Valve at Farley 2; the Section with the Leak was Unisolable

Case History

Several PWR's representing the designs of two nuclear steam system suppliers reported leaking and/or cracking in 1979 and 1980[13]. These cracks occurred in the feedwater lines immediately adjacent to the steam generator feedwater nozzles. During hot standby conditions, feedwater pumps are off and hot water from the steam generator can flow into the feedwater lines, resulting in layering. This alone can lead to cyclic thermal fatigue as the interface moves up and down. In addition the feedwater pumps may be jogged when the operator notices that the level in the steam generator has dropped; such jogging results in severe turbulence and a marked thermal gradient. The feedwater is about 38°C (100°F) while the steam generator is 260°C (500°F). Cracking generally occurred at the weld joint attaching feedwater pipe to nozzle. The counterbores usually had a sharp corner with a high stress concentration factor so this region was the focal point for high and low-cycle thermal fatigue cracking.

Specific Cause and Corrective Action

Turbulent mixing in the range 0.1 to 10 Hz led to high-cycle fatigue. Movement of the hot/cold interface up and down leads to low-cycle thermal fatigue. Several corrective actions were employed, not all at all plants. Heated feedwater, redesign of piping to include a separate auxiliary feedwater system and recirculation loop, improved oxygen control in the feedwater, installation of a protective liner, and improved counterbore design, eliminating the sharp corner were used. The USNRC in IN 91-28[14] closed this issue, considering it to be resolved.

Global Thermal Stratification

Pressurizer Surge Line

Global thermal stratification is a flow condition in which the separate thermal layers of fluid are stable and vary slowly with time. Obviously this can be a mechanism for pipe movement and potential damage to the pipe, the supports, hangers and restraints.

Systems affected have been pressurizer surge lines, BWR feedwater systems, PWR feedwater systems, PWR/RHR suction lines and BWR HPI systems. Information sources relevant to global thermal stratification are Information Notices 84-87[15] and 91-38[16], Bulletin 88-11[17], the 1991 ASME PVP Thermal Stratification Panel[18] and AEOD/S902[19].

During power ascension in pressurized water reactors, the Reactor Coolant Loop and the Pressurizer contain fluid at different temperatures. These portions of the Reactor Coolant System are connected by the Pressurizer Surge Line. Pressure in the Reactor Coolant System is maintained by controlling the pressure within the Pressurizer using electric heaters and sprays. The intermittent activation of heaters and spray causes an exchange of fluid, at low velocities, between the Pressurizer and the Reactor Coolant Loop. The flow is generally slow and laminar resulting in ideal conditions for thermal stratification. As the temperature of the Reactor Coolant Loop fluid increases, it expands causing an insurge of fluid into the Pressurizer; at the same time some of the hotter fluid within the Pressurizer flows out to heat the Reactor Coolant System. Thermal stratification of the fluid in the Pressurizer Surge Line has been observed during this phase of system heatup. The Pressurizer maintains the temperature of the fluid at approximately 400-650°F (205-345°C) during system heatup. Reactor Coolant Loop temperatures vary between 120-615°F (50-340°C). The differences in bulk fluid temperatures between these parts of the Reactor Coolant System have been measured to be as large as 320°F (180°C). Higher temperature differences are possible. During normal operating modes, the bulk fluid temperature differences have been observed between 0° and 100°F (0° and 55°C)

During conditions of rapid flow in the Surge Line (caused by Reactor Coolant Pump start/stop, rapid boron injection, or activation of the Pressurizer spray valves), the high velocities tend to mix the fluids, creating a homogeneous thermal condition. However, upon return to normal flow conditions in the Surge Line, the fluids again return to a stratified flow condition.

Case History

Trojan[16] exhibited unexpected movement of the pressurizer surge line for several years. This movement led to gap closures and overall line displacement. The hot layer may be 425°F while the cold layer is 125°F. Obvious effects are undefined deflections not covered by the design specification required by ASME III.

Corrective Action

Several actions have been proposed, including an overall temperature limitation which includes bubble formation and collapse, increased times for both heatup and shutdown, monitoring of temperatures and deflections, enhanced inservice inspection, system modification and use of the SCATS Program.

RECOMMENDATIONS

- Use a technique/standard such as OM-3 to determine levels of vibration requiring corrective action.

- Examine excitation mechanisms in systems to determine the potential for adverse effects and failure.

- Minimize discontinuities on smaller lines such as compression fittings and socket welds that could lead to cracking or failure due to vibration.

- Determine whether conditions exist leading to mixing-tee failures such as large temperature differences in coolant streams that are combining. If so, minimize contact with the pipe wall with thermal sleeves.

- Monitor locations with large temperature differences thermally and with ultrasonics.

- Limit stagnant horizontal lines such as the pressurizer surge line to prevent the hot stream diffusing over the cooler liquid; a suggested approach is to introduce a definite slope in such lines.

- Monitor valves for leakage between the seat and the gate; the lower pressure portion should be monitored for leakage by measuring temperature changes.

- Beware of stagnant conditions such as hot standby where fluid behavior differs markedly from normal flow.

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