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Residual Life Assessment of Major Light Water Reactor Components—Overview

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Instructions: Please make the following pen and ink corrections to your copy:

Page 65, Figure 5.3 Legend

LIT = Safety injection tank, change to read:

SIT = Safety injection tank

Page 221, Figure 10.9, pseudo-stress amplitude equation

$S_a = 1/2\ K_1 K_a S_n$, change to read:

$S_a = 1/2\ K_t K_e S_n$

Please Note: Chapter 11 numbering inadvertently skips from 11.1.1 CRDMs, to 11.2.2, Reactor Internals. This is merely a numbering error and will not be corrected. No material has been omitted.

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B. F. Beaudoin	Robert L. Cloud Associates	PWR coolant pumps
B. J. Buescher	EG&G Idaho	BWR feedwater and steam line piping. Countermeasures for cracking in BWR recirculation piping
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ABSTRACT

This report presents an assessment of the aging (time–dependent degradation) of selected major light water reactor components and structures. The stressors, possible degradation sites and mechanisms, potential failure modes, and current inservice inspection requirements are discussed for eleven major light water reactor components: reactor coolant pumps, pressurized water reactor (PWR) pressurizers, PWR pressurizer surge and spray lines, PWR reactor coolant system charging and safety injection nozzles, PWR feedwater lines, PWR control rod drive mechanisms and reactor internals, boiling water reactor (BWR) containments, BWR feedwater and main steam lines, BWR control rod drive mechanisms and reactor internals, electrical cables and connections, and emergency diesel generators. Unresolved technical issues related to understanding and managing the aging of these major components are identified.

EXECUTIVE SUMMARY

As part of its responsibilities to protect the health and safety of the public, the United States Nuclear Regulatory Commission (USNRC) is concerned about the aging of the major components, structures, and safety systems in nuclear power plants. Therefore, the USNRC Office of Nuclear Regulatory Research is sponsoring a Nuclear Plant Aging Research (NPAR) program at several national laboratories, including the Idaho National Engineering Laboratory. One of the NPAR program tasks is to understand the aging of the major light water reactor structures and components and identify the unresolved technical issues associated with this aging. This task will also assess different methods of managing this aging. These methods include inspection, surveillance, and monitoring techniques for the detection, sizing, and trending of any degradation, and maintenance techniques to mitigate the damage. Emphasis has been placed on integrating, evaluating, and updating current technical information about the relevant degradation mechanisms and operating experience.

The light water reactor structures and components to be evaluated were selected and prioritized according to their relevance to plant safety; the prioritization was discussed in the first volume of this report. The stressors, possible degradation sites and mechanisms, potential failure modes, and inservice inspection methods for seven major components were also discussed in the first volume: (a) boiling water reactor (BWR) and pressurized water reactor (PWR) pressure vessels, (b) PWR containments and basemats, (c) PWR reactor coolant piping, (d) PWR steam generators, (e) BWR recirculation piping, and (f) reactor pressure vessel supports. The unresolved technical issues related to aging of these components were also identified. The remaining eleven major components are discussed in this volume (Volume 2) of the report: (a) reactor coolant pumps, (b) PWR pressurizers, (c) PWR pressurizer surge and spray lines, (d) PWR reactor coolant system charging and safety injection nozzles, (e) PWR feedwater piping and nozzles, (f) PWR control rod drive mechanisms and reactor internals, (g) BWR containments, (h) BWR feedwater and main steam line piping, (i) BWR control rod drive mechanisms and reactor internals, (j) cables and connectors, and (k) emergency diesel generators. Unresolved technical issues related to the aging of these components are identified. Countermeasures, that is, mitigation, repair and replacement methods, which will minimize or prevent aging related failures in two major components, the PWR steam generator tubes and the BWR recirculation piping, are also discussed. A draft of this report was published in June 1988. The editors of the report have since revised several chapters and incorporated relevant technical information that became available after publication of the draft and, therefore, take full responsibility for the material presented in this document.

Light Water Reactor Coolant Pumps

The LWR cast stainless steel reactor coolant pump bodies are susceptible to thermal aging and fatigue damage. Thermal aging results in a slow loss of material toughness over extended periods of time and is influenced by coolant temperature and ferrite content and its distribution in the microstructure. Pump body fatigue damage is caused by the system operating transients, pump vibrations (possibly) and high residual stresses introduced by welding or heat treatment, but damage is expected to be quite small. The pump shafts are also susceptible to high-cycle mechanical and thermal fatigue damage, and shaft damage (fatigue cracks) and failure have occurred. Some PWR pump body closure studs have been damaged by borated primary coolant leakage, which caused corrosion-wastage of the bolts. The potential modes of failure of the pump body are through-wall leakage of the primary coolant or unstable ductile tearing. Failure of attachment welds may result in broken pieces of pump internals that may be carried over to the reactor pressure vessel and damage vessel internals and core components.

The inservice inspection requirements include surface and volumetric examination of fabrication welds and were originally developed for Type F pumps which have high residual stresses at the welds. However, these requirements may not be practical or meaningful for Type C and E pumps, having different geometric configurations, fabrication that includes complex welds, and heat treatment that introduces residual stresses throughout the pump body. (Type E and Type F pumps are used in PWR plants, and Type C pumps are used in BWR plants.) The actual degree of thermal-aging embrittlement of the pump body should be monitored to define the lower-bound toughness levels; advanced ultrasonic testing methods are recommended to detect cracks in the pump shaft, and cracks and corrosion wastage in the closure studs; and recommended gasket maintenance practices should be followed to prevent leakage of borated coolant.

PWR Pressurizers

Fatigue is a pervasive degradation mechanism throughout PWR pressurizers. Low–cycle fatigue damage is caused by plant heatup and cooldown cycles, plant unloading and loading at power, step load increases and decreases, reactor trips, hydrotests, etc. The surge line nozzle and thermal sleeve are particularly affected by the insurge of relatively cooler hot leg coolant and the outsurge of hot pressurizer fluid associated with power changes. The spray line head, nozzle, and thermal sleeve are susceptible to fatigue damage caused by the subcooled spray actuations associated with power changes. The pressurizer walls may be susceptible to both the low–cycle fatigue damage caused by the plant operational transients and high–cycle thermal fatigue caused by impact of the subcooled spray on the pressurizer walls, sloshing of the liquid at the steam–water interface, and water level changes caused by insurges, outsurges, and heater actuations. The key fatigue degradation sites are calculated to have high usage factors and include the pressurizer walls near the usual steam–water interface, the spray head, and the spray and surge line nozzles. The cast stainless steel spray heads are also susceptible to thermal aging (embrittlement) and erosion.

The heater sheaths and sleeves and instrument nozzle sleeves are susceptible to intergranular stress corrosion cracking. Pressurizer manway bolts can be and have been damaged by leaking primary coolant, which causes stress corrosion cracking. Leakage of borated coolant can also cause corrosion and wastage of the nearby carbon steel base metal. Potential failures include ductile tearing and through–wall cracks leading to leakage of the primary coolant (pressurizer wall near the usual steam–water interface and surge or spray line nozzles), excessive wear and cracking of the spray heads, heater sheath and sleeve cracks, instrument nozzle sleeve cracks, and manway cover leakage.

The inservice inspection requirements include surface and volumetric examination of the welds. The frequency of the pressurizer nozzle weld inspections needs to be increased, and nondestructive examinations and loose part monitoring that can assess the condition of the thermal sleeves are needed. Monitoring of the thermal and pressure transients and refined fatigue analysis are needed. Appropriate monitoring techniques that will detect any borated coolant leakage at the heater or instrument nozzle sleeves and the resulting corrosion of the base metal should be implemented.

PWR Pressurizer Surge and Spray Lines and Nozzles

The PWR pressurizer surge and spray lines are also very susceptible to both low– and high–cycle fatigue damage. Low–cycle fatigue is caused by the same relatively severe temperature and pressure changes associated with plant operational transients (heatups, cooldowns, trips, leak tests, etc.) that cause fatigue damage in other parts of a PWR primary system. The surge lines are also subjected to (and designed for) tens of thousands of relatively severe temperature changes [up to 60°C (110°F) resulting from the insurges and outsurges caused by relatively small power loadings and unloadings. However, the surge lines are also subjected to stratified flows, especially during reactor heatup and cooldown when the temperature difference between the pressurizer and the hot leg coolants is large [a temperature difference as high as 180°C (325°F) has been measured] and during certain plant operating modes that introduce low or stagnant flow conditions in the surge lines. Stratified flows introduce high–frequency thermal striping loads near the interface between the hot and cold fluids that are capable of initiating a fatigue crack on the pipe inside surface. In addition, stratified flows introduce through–wall bending stresses that are capable of both initiating and propagating fatigue cracks. Stratified flows have caused large deflections of some surge lines, and in at least one case, inelastic deformation of the pipe. The horizontal portion of the surge line piping, the highly stressed elbows, and the surge nozzle on the pressurizer are all likely to suffer high fatigue damage. Low or stagnant flow conditions in the surge line piping may also result in a local slug of relatively cool liquid, the movement of which will impose thermal shock stresses and additional fatigue loads on the piping. The surge lines in some PWRs are made of cast stainless steel and are also susceptible to damage caused by thermal embrittlement. Stratified flows and alternating steam and water flows have also occurred in PWR spray lines during some plant operations. Temperature changes of up to 300°C (~530°F) are possible, which can cause extreme thermal shock loadings and flow stratifications in the horizontal portions of the spray lines.

The potential failure mode (for both the surge and spray lines) is a through–wall crack leading to leakage of the coolant. Preliminary analysis indicates that a surge line subjected to stratified flows will leak before it will rupture. However, the leak–before–break concept may not be applicable to small–diameter spray lines subjected to thermal stratification. A break in either a surge or spray line would be an unisolatable breach in the primary coolant pressure boundary and could create a severe thermal hydraulic transient. There have been no PWR pressurizer surge or spray line failures to date. Nevertheless, the fatigue damage resulting from stratified flows, thermal striping and thermal shocks (caused by the movement of a slug of locally cooled water), and the thermal aging were not considered in the original design calculations. The estimated fatigue usage factors are near the ASME Code limit, and failures may yet occur. Clearly, the coolant temperatures, pressures, flow rates, and pipe wall temperatures should be monitored and recorded so as to facilitate better estimates of the low–cycle fatigue damage to both the surge and spray line base metal and welds. The high–cycle fatigue behavior of thermally aged cast stainless steel piping also needs to be evaluated. The ASME Code inservice inspection requirements include surface and volumetric examinations of welds but do not include inspection of the base metal. More frequent examinations of the nozzle welds, inspection of highly stressed elbows, and nondestructive examinations of the thermal sleeves are recommended. The use of acoustic monitoring to detect fatigue crack growth in the base metal should be evaluated. The potential for thermal stratification in the surge line can be reduced by decreasing the temperature difference between the pressurizer and hot leg coolants during heatups. Fatigue damage to the spray line caused by stratified flows can be mitigated by maintaining full flow at all times and by changing the piping layout to eliminate horizontal runs.

PWR Reactor Coolant System Charging and Safety Injection Nozzles

The PWR coolant system charging and safety injection nozzles are also susceptible to fatigue damage. Again, low–cycle fatigue is caused by the same temperature and system pressure changes associated with plant operational transients that cause fatigue damage in other parts of a PWR primary system. In addition, the charging nozzles are subjected to a relatively severe and complex thermal transient each time there is a loss–of–charging event (loss of letdown flow, loss of charging pumps, coolant volume control system isolation, etc.). Each loss–of–charging event results in an approximate 85°C (185°F) nozzle temperature change followed by a severe thermal shock upon resumption of the charging flow. The safety injection nozzles are also susceptible to additional fatigue damage caused by thermal shock loads during a safety injection system actuation [the cold leg fluid at a temperature of about 290°C (555°F) is replaced by 50°C (120°F.) injection tank water]. Also, local areas of stratified flow may develop in the safety injection system piping and nozzles (caused by stagnation and valve leakage) which result in thermally induced bending stresses and thermal striping. Again, stratified flows can cause significant temperature differences between the top and bottom portions of a pipe or nozzle and large bending moments. Flow–induced vibrations can also affect the fatigue life of these nozzles. Some of these stressors (especially the presence of stratified flows) were not fully considered in the original design fatigue calculations but have caused through–wall fatigue cracks. These thermal transients should be monitored so as to facilitate better estimates of the fatigue damage to both the base metal and welds. The potential failure modes are loss of nozzle protection caused by thermal sleeve cracking, and through–wall cracks leading to leakage of the coolant. The inservice inspection requirements include surface and volumetric examinations of the welds. More frequent examinations of the nozzle welds and inservice inspections of the highly stressed regions of the base metal are recommended. Loose part monitoring may be used to assess the integrity of the thermal sleeves. On–line techniques to monitor any leakage from faulty or degraded valves need to be developed.

PWR Feedwater Piping and Nozzles

Pressurized water reactor carbon steel feedwater piping is susceptible to erosion–corrosion and fatigue damage. The key degradation sites subjected to erosion–corrosion damage are on the piping inside surfaces near elbows, fittings, and geometric discontinuities. The main factors that influence the erosion–corrosion damage of carbon steel piping are local flow velocity; oxygen content, pH level, and impurities in the feedwater; coolant temperature; and piping material alloying elements. Erosion–corrosion of carbon steel piping caused by single–phase, subcooled flow is called flow–assisted corrosion. If the feedwater pressure is close to the saturation pressure, cavitation can also cause erosion–corrosion damage. The erosion–corrosion damage can be very localized, and nondestructive inspection methods that ensure detection of minimum wall thickness are being developed. The sites subject to fatigue damage are the feedwater nozzles, horizontal portions of the piping, and the piping inside surface adjacent to the mixing layers in the stratified flows. Stressors that cause fatigue damage include stratified flows, thermal shocks, flow–induced vibrations, and water hammers. The steam generator feedwater nozzles are susceptible to fatigue damage caused by (a) thermal shocks associated with the introduction of relatively cold feedwater (from the auxiliary feedwater system or when the feedwater piping is steam filled) and (b) stratified flows.

The potential failure modes for the PWR feedwater piping are catastrophic failure caused by wall thinning and through-wall fatigue cracks leading to leakage. ASME Code inservice inspection requirements include surface and volumetric examinations of welds in Class 2 piping, that is, piping within containment. However, there are no formal ASME or USNRC inservice inspection requirements for the balance-of-plant piping, that is, feedwater piping outside the containment. (The NRC has asked the utilities to inspect their feedwater piping because of the recent pipe failure at the Surry plant.) New inspection methods using radiography and ultrasonic testing techniques, which are able to measure pipe wall thinning caused by erosion-corrosion, have been developed. Use of on-line monitoring methods to determine erosion-corrosion damage needs to be evaluated because of the significant uncertainty regarding the erosion-corrosion rates. A higher pH level (9.2) and reduced impurities in the feedwater will help mitigate erosion-corrosion damage. Alternate piping materials with higher chromium content, modified piping layouts, and stainless steel coatings can also significantly reduce erosion-corrosion damage.

PWR Control Rod Drive Mechanisms and Reactor Internals

The PWR control rod drive mechanism (CRDM) housings and their welds, and the couplings between the control rod assemblies and the CRDMs are susceptible to low-cycle fatigue damage caused by plant heatups and cooldowns. However, typical fatigue usage factors for CRDM components are low. Some of the housings are fabricated from cast stainless steel and, therefore, are susceptible to thermal aging. The degree of thermal aging is influenced by coolant temperature, and ferrite content and its distribution in the microstructure. The latchings and unlatchings that occur during normal operation cause mechanical wear of the CRDM internal components. The potential failure modes for the CRDMs are cracks in the CRDM housing welds leading to a leakage of primary coolant and mechanical binding of the latch assembly causing a stuck rod. The leakage of borated coolant can cause corrosion of the low alloy steel base metal. Adequate monitoring techniques are needed to detect boric acid leakage before it causes significant corrosion. The inservice inspection requirements include volumetric and surface examinations of 10% of the peripheral CRDM housing welds (the interior welds are inaccessible and, therefore, exempt). Life tests for the latch assemblies and the electrical insulation are needed. Techniques for measuring the cumulative length of lead screw travel or counting the number of latch steps should be developed to aid in the CRDM replacement decision.

The thimble tubes, the high-strength steel bolts used on the reactor internals, the thermal shield, and the core barrel are subject to high-cycle fatigue damage caused by flow-induced vibrations. High-cycle fatigue curves for high-strength steel bolting materials need to be developed. The high-strength fasteners are also subject to stress corrosion cracking and stress relaxation caused by neutron irradiation. Other degradation mechanisms acting on the reactor internals are irradiation and thermal embrittlement, wear, and fretting. A research program is needed to determine the combined effects of radiation and temperature, which cause embrittlement of the austenite and ferrite phases, respectively, in the cast stainless steel components. Potential (and actual) reactor internals failure modes include leakage from a thinned thimble tube (a breach in the primary pressure boundary), broken bolts, loose parts, and fuel damage from baffle jetting. The inservice inspection requirements include visual examinations of the accessible surfaces of the reactor internals. Vibration monitoring programs to detect degraded or broken reactor internals should be established. Bolting and pin materials with extended lifetimes should be developed, possibly through the use of improved Alloy X-750, Alloy 718, and Alloy A-286 heat treatments.

Countermeasures for PWR Steam Generator Tube Failures

The primary side of some PWR steam generator tubing is susceptible to primary water stress corrosion cracking (PWSCC); Combustion Engineering and Babcock & Wilcox units are much more tolerant than most Westinghouse units. High yield strength tubing [>380 MPa (55 ksi)] processed using low mill annealing temperatures is more susceptible to PWSCC than lower strength tubing processed using higher annealing temperatures. High residual stresses caused by tube straightening, bending, or expansion processes, and tube denting also make tubing more susceptible to PWSCC. Shot and rotopeening of tubing inside surfaces in the tube sheet area, and thermal stress relief of the tubing in Rows 1 and 2, have been used to reduce the residual stresses and mitigate the PWSCC damage. Reduction of primary water temperature and hydrogen content increases resistance to PWSCC. The benefits of increased pH via higher lithium concentration or the use of enriched boron is still under evaluation.

Significant depletion of chromium at the grain boundaries of Alloy 600 makes the secondary side of the PWR steam generator tubing susceptible to damage by IGSCC and intergranular attack (IGA). Thermally treated Inconel 690 used in new steam generators has an optimum microstructure, which includes intergranular carbides and no chromium depletion at the grain boundaries, and, therefore, resists both PWSCC on the primary side and IGSCC/IGA on the secondary side. The major countermeasures for mitigating IGSCC/IGA damage are strict control of the secondary water chemistry, use of chemical additives to neutralize crevice alkalinity, tube rolling to eliminate crevices, sludge lancing, and effective crevice flushing. A remotely operated sludge lancing and inspection process is being developed for removing sludge thoroughly from all sides of the tubes and inspecting tube bundle conditions as the work progresses. Condensate polishers remove impurities from the secondary water and provide defense against faulted water chemistry conditions. However, proper design and operation of polishers are critical to avoid release of resins or regeneration chemicals (NAOH or H_2SO_4) into the secondary coolant.

Other degradation mechanisms that may affect the secondary side of the tubes include pitting, denting, wastage, high-cycle fatigue, fretting, and erosion-corrosion. Leak-tight condensers and control of the chlorides, copper, and oxygen in the secondary coolant will minimize the potential for pitting and denting. This can be accomplished by the use of titanium or stainless steel condenser tubes, elimination of copper alloys from the feed trains, and the use of stainless steel support plates. All volatile treatment water chemistry mitigates wastage damage experienced with phosphate water chemistry but lacks significant buffering to neutralize crevice alkalinity. A smaller gap size between the antivibration bars and the tubes, and a reduced recirculation flow will mitigate high-cycle fatigue damage in certain steam generator designs.

Various nondestructive evaluation techniques can detect and size relatively large flaws in the tubes but cannot conclusively identify degradation mechanisms. Efforts are needed to quantify the flaw growth rates to determine safety margins during operation.

Sleeves and nickel plating may be used to cover defects in the tube sheet or tube-support plate regions. The field performance of the various sleeve designs should be monitored because the use of sleeves can introduce residual stresses that cannot be measured, may present difficulties for future inspections, may form crevices on the primary side, and can introduce geometric stress raisers. Nickel plating has several advantages over sleeving. It generates very low residual stresses and can be applied anywhere in the straight part of the tube. An ultrasonic inspection method has been developed to examine nickel-plated regions.

Plugging is commonly used when unacceptable flaws are detected in regions away from the tube sheet. Plugs are also used on Rows 1 and 2 as a preventive measure. PWSCC may damage the plugs if low-mill annealing temperatures are used during heat treatment. If PWSCC causes a plug failure, the fragments of the failed plug may puncture the tube. Plugs can be removed for future repairs, if needed.

BWR Containments

Twenty-six domestic BWR plants have metal containments; ten plants have concrete containments. Corrosion is the major degradation mechanism for the metal containments. BWR environments are very humid. Therefore, the interior surfaces of the drywells are susceptible to general corrosion when the coatings are deteriorated, and the embedded shell regions of the drywells are susceptible to pitting and crevice corrosion when the caulked joints at the concrete-metal interface are degraded. The interior surfaces of the pressure suppression chambers are susceptible to general attack and pitting when the coatings are deteriorated; corrosion caused by differential aeration, that is, a gradient in the amount of dissolved oxygen near the waterline; and microbially influenced corrosion below the waterline. In one plant, the overall corrosion rate on the inside surface of the torus wall was found to be more than double the expected rate of 0.041 mm/year (0.0016 in./year) because of the deteriorated coating. The exterior surfaces of the Mark I and II drywells are also susceptible to general corrosion when the surface coatings are deteriorated; pitting and crevice corrosion when wet and degraded fill material is present in the gap between the shield wall and drywell; and pitting, crevice and microbially influenced corrosion when the gaps are not sealed and leaking coolant keeps the sand in the pocket near the drywell base wet. An average local corrosion rate of 0.43 to 0.51 mm/year (0.017 to 0.020 in./year) was detected in one plant at the exterior surface of the Mark I drywell near the sand pocket.

The stainless steel bellows are susceptible to intergranular stress corrosion cracking in the heat-affected zones and transgranular stress corrosion cracking in the cold-rolled portions. The high-energy piping penetrations, vent lines, bellows, and the sites of geometric discontinuities are subject to low-cycle fatigue damage from cyclic thermal loadings caused by operating transients, pressure tests, and safety relief valve discharge tests.

The potential failure modes are leakage of radioactive gases and loss of structural integrity. The best protection against corrosion is periodic inspection of the coatings, and if found deteriorated, recoating with a zinc-rich material. The inservice inspection requires leakage testing and visual examination. The suppression chamber must be drained or underwater inspection techniques must be employed to examine the submerged surfaces. The exterior surfaces of the Mark I and II drywells are not accessible for visual inspection. Therefore, thickness measurements of the drywell shell at selected sites are needed to assess corrosion damage. Cathodic protection and zinc-rich coatings will help mitigate corrosion of metal containments. A sealant at the concrete-metal interface should be maintained to prevent moisture from entering the embedded shell region.

All BWR concrete containments, except the two Mark III containments, are completely enclosed in a reactor building that protects them from the degrading effects of harsh external environments. However, internal chemical reactions can also cause cracking and spalling of the concrete. The reinforcing steel is susceptible to rapid corrosion caused by harsh environments when the cracks in the concrete are opened sufficiently and by stray electrical currents which may be present in older plants. The reinforcing steel and metal liner are susceptible to fatigue damage caused by cyclic thermal loads, pressure tests, and safety relief valve tests. The metal liner is also susceptible to corrosion caused by the humid internal environment. The posttensioning system anchors and tendon wires are susceptible to hydrogen embrittlement and corrosion caused by the high tensile preloads and trapped water and moisture. Information on the long-term degradation of reinforcing steel is needed. A comprehensive inservice inspection program is needed to identify and quantify any concrete containment degradation.

BWR Feedwater and Main Steam Line Piping

The boiling water reactor carbon steel feedwater and main steam line piping systems are susceptible to fatigue and erosion-corrosion damage. The major stressors causing fatigue damage to the feedwater nozzle and the horizontal portions of the piping systems are stratified flows, thermal shocks, mechanical shocks caused by water or steam hammers, and flow-induced vibrations. Test results show that the BWR environments cause fatigue crack initiation in carbon steel piping at far fewer cycles than that predicted using the in-air test data on which the ASME Code fatigue design curves are based. However, use of hydrogen water chemistry will reduce the oxygen level in the feedwater, which is likely to reduce fatigue crack growth rates in carbon steel piping. Therefore, corrosion fatigue data for carbon steel piping are needed to estimate both low- and high-cycle fatigue damage. On-line monitoring to assess low-cycle fatigue damage is recommended.

The major stressors causing erosion-corrosion damage by oxide dissolution are local flow velocity; coolant temperature, pH level, and oxygen content; and piping layout and material composition. An additional stressor essential for the erosion-corrosion of the steam lines is steam quality; no damage has been observed in systems carrying dry steam. The key degradation sites for local erosion-corrosion damage are near elbows, fittings, welds, and other geometric discontinuities. In addition, uniform erosion-corrosion, called tiger striping, has been found in straight sections of the main steam lines. Droplet impact wear also causes erosion-corrosion damage in the main steam line piping. Significant erosion-corrosion damage to the feedwater piping is less likely in a BWR plant than in a PWR plant because of the high oxygen content in the BWR feedwater. However, BWR plants with hydrogen water chemistry may be more susceptible to erosion-corrosion damage. Therefore, a baseline inspection of the piping wall thickness prior to implementing hydrogen water chemistry, and periodic inspections thereafter, should be performed to determine the erosion-corrosion rates. Alternate piping materials with higher chromium content, modified piping layouts, and stainless steel coatings can significantly reduce erosion-corrosion damage.

The potential failure modes are through-wall fatigue cracks leading to leakage, and catastrophic failure caused by wall thinning. Again, the inservice inspection requirements include surface and volumetric examinations of Class 1 piping welds, that is, the welds on the piping within the containment. New inspection methods using radiography and ultrasonic testing techniques are being developed to measure pipe wall thinning caused by erosion-corrosion.

BWR CRDMs and Reactor Internals

The BWR CRDM pressure housings are subjected to low-cycle fatigue loads during heatups, cooldowns, and scrams. Stub tubes were employed between the pressure housings and the reactor pressure vessel lower heads of plants designed before 1974. The stub tube welds have sensitized material in the heat-affected zones and high residual stresses end, therefore, are susceptible to IGSCC. The diaphragms in the solenoid-operated valves become brittle over time and break up. The potential failure modes are cracks in the CRDM housing welds leading to leakage. Broken diaphragm pieces may block the vent ports in the scram valves, and plant safety may be compromised. The inservice inspection requirements include volumetric and surface examination of the 10% of the peripheral CRDM housing welds. It is difficult to inspect the stub tube welds, and advanced inspection methods are needed to assess their integrity. Use of hydrogen water chemistry significantly reduces the level of oxygen in the BWR coolant and mitigates the damage caused by IGSCC. A program for periodic inspection of the CRDM internals for excessive wear damage is also needed.

Several BWR reactor internals, for example, jet pumps, feedwater spargers, fasteners, and the core plate, have highly stressed materials with chromium depleted grain boundaries, crevices, or cold work, and are susceptible to IGSCC. The heat-affected zones of the attachment welds of the reactor internals to the pressure vessel are also susceptible to IGSCC, and IGSCC cracks may propagate into the pressure vessel base metal. The top guide structure and core shroud are exposed to relatively high fast neutron fluences and are susceptible to irradiation-assisted stress corrosion cracking (IASCC), which may occur at relatively low stresses. The jet pumps and feedwater spargers are susceptible to high-cycle fatigue caused by flow-induced vibrations. Cast stainless steel components such as orificed fuel support pieces may experience both thermal and irradiation embrittlement. The inservice inspection requires visual inspection of the reactor internals that are accessible. However, these methods are not adequate to detect flaws in the reactor internals and in the attachment welds; remote inspection tools are needed to detect IGSCC and IASCC cracks at these sites. Use of hydrogen water chemistry can mitigate the IGSCC damage, but its effect on IASCC is not fully understood. Fatigue crack initiation and growth rate data from specimens tested in a BWR environment with hydrogen water chemistry are needed to better estimate the high-cycle fatigue damage to the feedwater spargers and jet pumps. High-cycle fatigue data are also needed for the high-strength materials such as Alloy X-750. The potential failure modes are cracks in the reactor internals leading to loss of fuel geometry, loose parts, or loss of adequate core flow.

Countermeasures for BWR Recirculation Piping Failures

IGSCC is the major degradation mechanism which effects the BWR recirculation piping. IGSCC generally occurs at susceptible sites with either chromium-depleted grain boundaries caused by weld or furnace sensitization, crevices, or cold work, when high tensile stresses are present. Three stress improvement methods (induction heating stress improvement, mechanical stress improvement, and heat sink welding techniques) introduce high residual compressive stresses on the pipe inside surface and mitigate the initiation of IGSCC. Hydrogen water chemistry and strict impurity control in the BWR coolant make the BWR operating environment less corrosive and help suppress IGSCC crack initiation and growth. Hydrogen water chemistry can reduce the coolant oxygen level to values below 20 ppb, and strict impurity control techniques can reduce the coolant conductivity to values below 0.2 μS/cm.

Hydrogen water chemistry and strict impurity control have shown a generally beneficial or benign effect on most of the BWR structural materials, such as Alloy X-750, Alloy 600, carbon steel, and Zircaloy 2. However, the general corrosion and material removal rates of the carbon steel and low-alloy steel components subjected to hydrogen water chemistry are significantly higher, until a stable corrosion film is established and localized damage caused by erosion-corrosion may continue to be higher than normal after extended operation. Therefore, a long-term evaluation of the erosion-corrosion of BWR carbon steel feedwater and main steam lines subjected to hydrogen water chemistry is recommended.

Weld overlay reinforcement has been the most widely used technique to repair recirculation piping. However, it is difficult to perform inservice inspections and detect and size the IGSCC cracks under weld overlay material. Improved ultrasonic methods have recently been developed to inspect piping under weld overlays for IGSCC cracks. These methods have been successful in detecting deep cracks in the original piping under the overlays. Stress improvement methods may be used to inhibit propagation of short cracks not exceeding 30% of the wall thickness. A higher inservice inspection frequency and larger inservice inspection sample sizes are required for repaired welds. Mechanical clamping devices have been designed to retard IGSCC crack growth and to prevent pipe breaks. These devices can be readily removed for inspection of the welds.

Type 308L weld metal has been found very resistant to IGSCC in a BWR environment and is used to provide a protective cladding on the piping inside surface. Types 304NG, 316NG, and 347NG are resistant to IGSCC in normal BWR environments and may be used as alternative materials for BWR piping. Hydrogen water chemistry and strict impurity control also mitigates transgranular stress corrosion cracking in Types 304NG and 316NG stainless steels. Solution heat treatment eliminates weld sensitization and the residual stresses produced during fabrication, and has been used to mitigate IGSCC in the replaced piping.

BWR and PWR Cables and Connections

Containment cable systems (cables and connections) consist of a wide variety of proprietary polymer components and designs. The cable systems are exposed to thermal, radiation, moisture, chemical, and physical stressors, all with the potential for causing aging degradation. There is generally insufficient containment ambient and hot-spot radiation and temperature data to accurately calculate the aging of cables and connections; therefore, monitoring of temperatures and radiation levels at cable system hot spots is recommended. The most likely causes of common-cause failures are (a) degradation caused by embrittlement and cracking followed by moisture diffusion into the cables; (b) moisture migration into the connections; (c) electrical leakage currents; (d) deformation/creep of connection insulations and jackets that compromise the seals; and (e) surface contamination and condensation on bare terminals. Methods for in situ monitoring of aging effects are under development but are presently ineffective for judging component aging either relative to the samples that were preaged for the original environmental qualification (EQ) tests or relative to current susceptibility to the modes of failure noted above. There are few maintenance needs for cable systems because they are passive. Periodic inspections at terminations and other access points can be helpful in detecting signs of degradation.

The cables in nuclear containments must perform properly under the harsh environments postulated for design-basis accidents (DBAs). The demonstration of operability through DBAs and for a qualified life was made in EQ programs where a specified 40-year life was targeted. The technical practices and documentation required and used for EQ have evolved over the years, so the basis for any present life assessment varies according to the time of the construction or operating permit of the plant. During this same period, research and experience have raised issues regarding the technical validity of the accelerated aging practices and certain other test or circuit performance aspects of past EQ programs. Therefore, the predictability of highly aged cable systems subjected to severe DBA conditions may be uncertain and the potential for common-cause failures is an important safety consideration.

Reanalysis of the original qualification preaging data, using any conservatisms between the specified and the actual operating environments, may be performed for life assessment of cable systems. However, the reanalysis should address all new qualification issues, such as synergistic interactions between thermal and radiation stressors, dose rate effects, and oxygen diffusion effects. Accelerated preaging and requalification testing of small samples removed from cable systems in an operating plant (hot spots) may also be used for life assessment.

Emergency Diesel Generators

The primary emergency diesel generator components that experience aging-related reliability problems are (a) the governor; (b) the fuel-oil injector pumps, nozzles, and high-pressure piping; (c) the turbocharger; (d) various starting system components; and (e) other instruments and controls. Together, these constitute the sites of over 55% of all aging-related EDG failures; the governor alone is the locus of some 12% of failures. The major stressors include (a) vibration (obviously inherent with such reciprocating engines); (b) fatigue and other adverse operating conditions; (c) poor design and application, and low manufacturing quality; (d) dust, humidity, and other environmental adversities; (e) poor maintenance and operation; and (f) deterioration of various working fluids, such as moisture in the compressed air, and contaminated fuel and lubricating oils. However, the most severe stressor is the fast-start/fast-load emergency operation required of each unit, and—even more so—the associated testing regimen currently required by NRC Regulatory Guide 1.108. Most plant technical specifications for emergencies (such as for loss of offsite power, or a loss-of-coolant accident) require EDG start and synchronization in 10 to 12 seconds and full loading, if needed, within 30 to 60 seconds; and Regulatory Guide 1.108 requires simulation of these events on at least a monthly basis.

Some of the more common degradation mechanisms are (a) corrosion or dust coating of electrical contacts; (b) binding of close–fitting parts, for a variety of causes; (c) plugging of strainers, filters, and small fuel openings; (d) high–cycle metal fatigue; (e) simple overstress and fracture; (f) erosion and cavitation; and (g) loosening or fracture of fasteners.

Recent research and investigation make it evident that compliance with such emergency operation and testing policies greatly aggravates the relatively few reliability problems inherent in the complex of mechanical/electrical components themselves. A change in the policies, particularly those related to testing, could have significantly beneficial results. Various studies recommend such changes, calling for less rapid acceleration and loading in both testing and emergency conditions, insofar as possible. Recent reevaluation of emergency power requirements appears to indicate that in all or most plants the current fast–start regimen is unnecessarily rigorous.

Instead of the stress–inducing fast–start testing, EDG operational condition and readiness would be monitored from data obtained during lengthened monthly test operations (using slower starts) and trended to detect adverse changes in equipment in its operation. Such would also enhance efforts at preventive maintenance and significantly increase operator awareness of the operational characteristics of the units. Maintenance precepts would be reliability–centered, and predictive and preventive in nature.

Other mitigating activities of merit include enhanced operation and maintenance programs, of which better training and more operational experience are key aspects; a shift from present rather prescriptive maintenance programs toward preventive maintenance predicted on trended observations; actions to reduce or control vibrations and other adverse site parameters; research on particularly troublesome components, such as governors, instruments and controls, and turbochargers to reduce their susceptibility to failures; and provisions for enhanced prelubrication on starts.

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CONTENTS

RESIDUAL LIFE ASSESSMENT OF MAJOR LIGHT WATER REACTOR COMPONENTS—OVERVIEW VOLUME 2

1. INTRODUCTION

There are currently 112 commercial nuclear power plants licensed to operate in the United States. The oldest operating plant is Yankee Rowe, which has been in operation for 29 years. There are 50 other plants that have had an operating license for more than 15 years. Several time–dependent degradation mechanisms not accounted for in the original design have caused failures and raised questions about the continued safety and viability of older nuclear power plants and, in particular, about the integrity of the primary coolant pressure boundary and the containment. Examples of recent aging–related problems include a pressurized water reactor (PWR) steam generator tube rupture caused by high–cycle fatigue, significant wall thinning of boiling water reactor (BWR) metal containments caused by corrosion, catastrophic failure of a "non-nuclear" portion of a PWR feedwater line caused by erosion–corrosion, and a through–wall crack in a safety injection pipe between the nozzle and the first check valve caused by thermal fatigue.

The problems associated with understanding and managing aging degradation have become a major focus of ongoing research sponsored by the United States Nuclear Regulatory Commission (USNRC). An important part of the USNRC research effort is the Nuclear Plant Aging Research (NPAR) Program being conducted at several national laboratories, including the Idaho National Engineering Laboratory (INEL).[1] One of the NPAR Program tasks at the INEL is to develop the appropriate technical criteria for the USNRC to assess the residual life of the major light water reactor (LWR) components and structures. These assessments will help the USNRC identify and resolve safety issues associated with LWR aging degradation and develop policies and guidelines for making operating plant license renewal decisions. A five-step approach is being pursued to accomplish this task:

1. Identify and prioritize the major reactor components according to their relevance to plant safety.

2. Identify for each component, degradation sites, mechanisms, and stressors; identify potential failure modes; and then evaluate current inservice inspection methods.

3. Assess advanced inspection, surveillance, and monitoring methods that can be used to detect, quantify, and trend aging degradation. Evaluate current and emerging mitigating methods to reduce aging damage.

4. Develop LWR structure and component residual life assessment procedures.

5. Support the development of technical criteria for license renewal.

The term *aging* is used in this report to describe the cumulative time–dependent degradation of a component, structure, or system, which, if unmitigated, may result in loss of function and impairment of safety. Time–dependent damage or aging can be caused by one or several different mechanisms active within a component, structure, or material, and, if not recognized and properly managed, may result in some type of failure or impairment of function. Aging or degradation mechanisms are often the result of interactions between design, materials, operational stressors, and environment, and may result in loss of fracture toughness, strength, and fatigue resistance. Poor design, improper material selection, or inadequate maintenance practices can accelerate the degradation. An identification and understanding of the design, materials, stressors, environment, and aging mechanisms will assist the USNRC in evaluating the current and advanced inspection, surveillance, and monitoring methods now being used (or proposed for use) to detect aging damage. Understanding these factors will also help the USNRC evaluate current and emerging techniques for mitigating aging damage.

This NPAR Program task is concerned with integrating, evaluating, and updating current technical information on relevant major component degradation mechanisms and nondestructive examination (NDE) methods. All available sources of information are used to accomplish this task. The sources of information include technical reports issued by the USNRC, the Electric Power Research Institute (EPRI), various reactor vendors and utilities, the Department of Energy, and various national laboratories; technical seminars; workshops and conferences; meetings of the American Society of Mechanical Engineers (ASME); and technical journals. Results from ongoing research and development programs of the Department of Energy's national laboratories have also been reviewed. Similar results from the utilities and nuclear steam supply system vendors have been useful. Inspection and Enforcement (I&E) Bulletins, Notices and Generic Letters, and the Nuclear Power Experience database regularly summarize commercial power plant experiences and provide a valuable resource for this task. Discussions with technical experts are, in some cases, the only available source of information on some subjects.

In recent years, the nuclear industry has initiated a major effort aimed at extending the life of existing reactors.[2] An important part of this overall industry effort consists of pilot studies at Surry 1 and Monticello. In many cases, the results from these pilot studies are similar to the NPAR results presented in this report. However, the primary objective of the industry pilot studies is to develop a technical basis for LWR license renewal (that is, to assess the feasibility of safe operation during an extended life without undue economic consequences); whereas, the main motivation for this NPAR task is to assess and mitigate aging damage in major LWR components during both the current and any renewed license periods. In addition, whereas the pilot studies address the aging of a particular type of pressurized water reactor (PWR) and boiling water reactor (BWR) plant, this NPAR task report attempts to address all types of PWR and BWR plants.

In addition to (and in support of) the industry pilot studies, EPRI has had a number of LWR component aging research programs, which are summarized in Appendix A (provided by EPRI). The material in Appendix A delineates the extent to which industry is addressing many of the aging issues and potential inadequacies identified in this report and elsewhere.

This report provides, in two volumes, a qualitative understanding of the aging degradation mechanisms active in major LWR components and represents completion of the first two steps listed above, and partial completion of the third step.[a] The results published in this report will be periodically updated and reevaluated as new aging-related data become available. Volume 1 of this report presents the major components critical to nuclear power plant safety during normal and off-normal operation, during design-basis accidents such as a hypothetical large-break loss-of-coolant accident or the design-basis earthquake, or during a severe accident.[3] The selected PWR and BWR components are listed in Table 1.1. Volume 1 also presents aging-related data, including degradation sites, stressors and environment, degradation mechanisms, potential failure modes, and current inservice inspection methods for seven major components: PWR reactor pressure vessels, PWR containment and basemat, PWR coolant piping and safe ends, PWR steam generators, LWR pressure vessel supports, BWR reactor pressure vessels, and BWR recirculation piping. Volume 1 also discusses the current NDE and life assessment methods and briefly summarizes the emerging methods in this field. The aging-related data for the remaining major components are presented in Volume 2.

Table 1.1 Selected major PWR and BWR components

<u>Major PWR Components</u>

1. Reactor Pressure Vessel
2. Containment and basemat
3. Reactor coolant piping, safe ends, and nozzles
4. Steam generators
5. Reactor coolant pump body
6. Pressurizer, and surge and spray lines
7. Control rod drive mechanisms
8. Cables and connectors
9. Emergency diesel generators
10. Reactor pressure vessel internals
11. Reactor pressure vessel supports
12. Feedwater lines and nozzles

<u>Major BWR Components</u>

1. Containment and basemat
2. Reactor pressure vessel
3. Recirculation piping and safe ends
4. Main steam and feedwater lines
5. Recirculation pump body
6. Control rod drive mechanisms
7. Cables and connectors
8. Emergency diesel generators
9. Reactor pressure vessel internals
10. Reactor pressure vessel supports

a. The conclusions and recommendations presented in this report represent the views of the authors and the editors, not necessarily those of the USNRC.

The work completed to date has identified unresolved technical issues related to operation of the major components. Resolution of these issues will ensure continued safe operation of the components, including operation for any renewed license period. The results presented in this report have provided input to the USNRC Technical Integration Review Group for Aging and Life Extension (TIRGALEX) and has helped that group identify and prioritize aging/life extension (LEX) issues and recommend actions to resolve the issues. The work has also identified the need for several modifications in the current codes and standards, and for the development of new codes and standards, to account for aging of major light water reactor components.

The issues related to codes and standards are being addressed by the American Society of Mechanical Engineers (ASME) Section XI Special Working Group on Plant Life Extension, and by the Nuclear Management and Resources Council/Nuclear Utility Plant Life Extension (NUMARC/NUPLEX) Working Group that works with the Board of Nuclear Codes and Standards (BNCS) Steering Committee on Nuclear Plant Life Extension (PLEX). There are several other Codes and Standards committees that provide guidance on Plant Life Extension: ASME Section XI Working Group on Operating Plant Criteria, ASME Nuclear Operation and Maintenance Committee Task Group on Plant Life Extension, Institute of Electrical and Electronics (IEEE) Working Group 3.4 on life extension of class 1E equipment, American Society for Testing and Materials (ASTM) Committee E-10 on Nuclear Technology and Applications, and the American Concrete Institute (ACI) Committee 365 on Service Life Prediction of Concrete Structures.

The remaining work in this NPAR task will address issues related to managing aging damage in the major components (Steps 3 through 5 above). This will include evaluation of the current and emerging inspection, surveillance, and monitoring methods used to detect and quantify aging degradation. Emphasis will also be placed on assessing mitigation, repair, and replacement techniques that can be used to counter aging damage. The issue of sample size and frequency of inservice inspections (so that aging damage is detected before it exceeds the maximum allowable damage) will be considered. Maximum allowable damage should be determined by considering the highest possible loads during off-normal transients and design-basis accidents. The results of these evaluations will provide a basis for the development of life-assessment procedures for the major components, which will assist the USNRC in formulation of license renewal policy, as well as with other regulatory applications.

Volume 2 of this report is organized into three major parts. The remaining major PWR components are discussed in Chapters 2 through 8. The remaining major BWR components are discussed in Chapters 9 through 12. Components common to both PWRs and BWRs are addressed in the final chapters. Each chapter (except Chapters 8 and 12) presents a design description of a component, and discusses corresponding stressors, degradation sites and mechanisms, potential failure modes, and inservice inspection methods. Chapters 8 and 12 discuss remedies, mitigation techniques, and repair and replacement methods.

Chapter 2 discusses the aging of PWR primary system coolant pumps. The chapter also addresses several issues related to the aging of BWR recirculation pumps. Chapters 3 through 7 discuss the aging of the PWR pressurizer, pressurizer surge and spray lines, reactor coolant system charging and safety injection nozzles, feedwater piping and nozzles, and control rod drive mechanisms and internals, respectively. The countermeasures, that is, mitigation, repair, and replacement methods for PWR steam generator tube failures are evaluated in Chapter 8. Chapters 9 through 11 address the aging of the BWR containment, main steam and feedwater lines, and control rod drive mechanisms and internals, respectively. Chapter 12 discusses the countermeasures for BWR recirculation piping failures. Chapters 13 and 14 address the aging of PWR and BWR cables and connectors, and emergency diesel generators, respectively. Chapter 15 summarizes the conclusions and our recommendations for managing the aging of the major LWR components. Appendix A presents a summary of EPRI projects related to aging of major LWR components.

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2. LIGHT WATER REACTOR COOLANT PUMPS

F. R. Drahos, W. L. Server, and B. F. Beaudoin

The reactor coolant pumps (RCPs) are important components in a light water reactor nuclear steam-supply system because they circulate coolant through the reactor such that core-heated fluid can be passed to a turbine or intermediate heat exchanger. Heat generated from the operation of the RCPs is also used in controlling heatup of the plant and for increasing the primary system coolant temperature during hydrostatic pressure tests.

This chapter discusses the factors contributing to the integrity of RCPs, and, in particular, the pump casings, which are part of the reactor primary coolant system pressure boundary and have been designated as a key component for license renewal.[1] The RCPs also play an important role in ensuring proper heat transfer from the reactor core. Therefore, the integrity of the other pump parts (shaft, impeller, motor, flywheel, closure fasteners, etc.) is important because they affect the operability of the pumps. The pump shaft seals are not discussed in this chapter because they are replaced or refurbished relatively frequently. Although this chapter focuses on pressurized water reactor (PWR) coolant pumps, some information is presented relative to boiling water reactor (BWR) coolant pumps because the general design and conditions of service are similar in both pumps.

2.1 Description

The RCPs consist of the pressure-retaining components (pump body and cover, closure bolting, and mechanical seal closure flanges) and the rotating members (pump shaft, mechanical seal internals, and gasketing). Other rotating members are the impeller and the flywheel (the flywheel is not a functional part of the RCP but controls shutdown in case of loss of power).

2.1.1 Geometry, Design, Vendors. Before 1971, reactor coolant pump components were designed and manufactured to meet the general requirements of the 1968 American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section III.[2] However, because of the unavailability of specific Code requirements, the reactor coolant pump bodies could not be Code stamped.

Reactor coolant pump requirements were added to the ASME Boiler and Pressure Vessel Code in 1971, and subsequent design of PWRs has adhered to those requirements. Reactor coolant pumps are also required to meet the Class 1 requirements listed in Subsection NB-3400 of the ASME Code. These requirements appear in the Owner's Design Specification as required by ASME Section III, NCA-3200. Class 1 requirements are original design responsibilities and do not directly relate to aging except that their intent must still be met for license renewal; the primary design concerns are minimum wall thickness (pressure retaining), operating loads, connected pipe loads (including earthquake loadings), and general erosion/corrosion.

Class 1 RCPs generally fall into one of the following design categories:

Type E Pumps (Figure 2.1) are manufactured by Byron Jackson Pump Division, Borg Warner Corporation and are used in both Babcock and Wilcox Company and Combustion Engineering, Inc., nuclear steam supply systems (NSSSs) for PWR plants. See the ASME Code, Section III, Figure NB-3441.5-1.

Type F Pumps (Figure 2.2) are manufactured by Westinghouse Electric Corporation, Electro-Mechanical Division, and are used exclusively in Westinghouse NSSSs and in some Babcock and Wilcox NSSSs for PWR plants. Type F pumps manufactured by Bingham-Willamette Company are also used in Babcock and Wilcox NSSSs for PWR plants. See the ASME Code, Section III, Figure NB-3441.6(a)-1.

Type C Pumps (Figure 2.3) are manufactured by Byron Jackson and are used primarily in General Electric Company NSSS BWR plants. Some Type C pumps manufactured by Bingham-Williamette have also been used in General Electric NSSSs for BWR plants. See the ASME Code, Section III, Figure NB-3441.3-2.

Type F Pumps (Figure 2.4) are manufactured by Combustion Engineering and Klein, Schanzlin and Becker and are used in Combustion Engineering NSSSs for PWR plants. See the ASME Code, Section III, Figure NB-3441.6(a)-1.

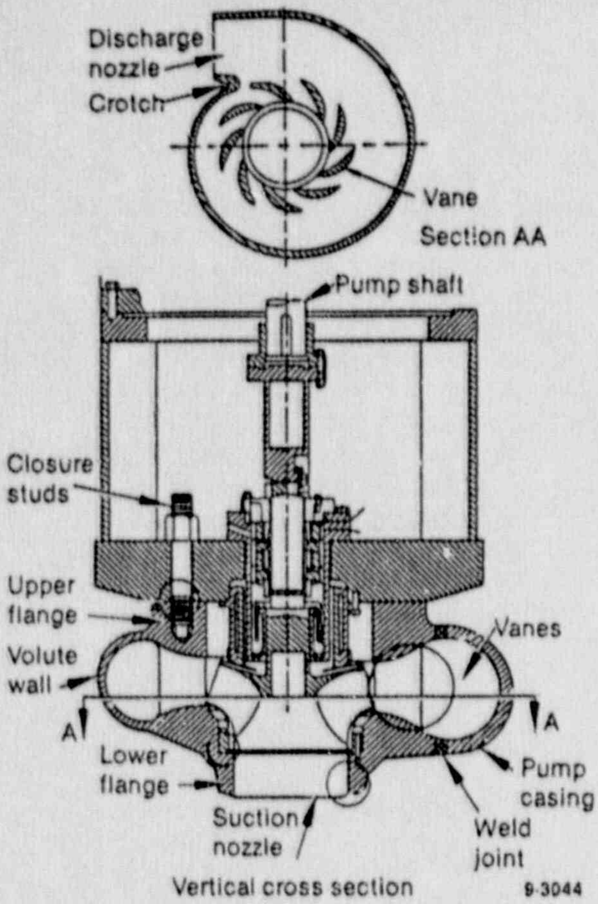

Figure 2.1. PWR Type E Coolant Pump. The high stress intensity locations are circled.

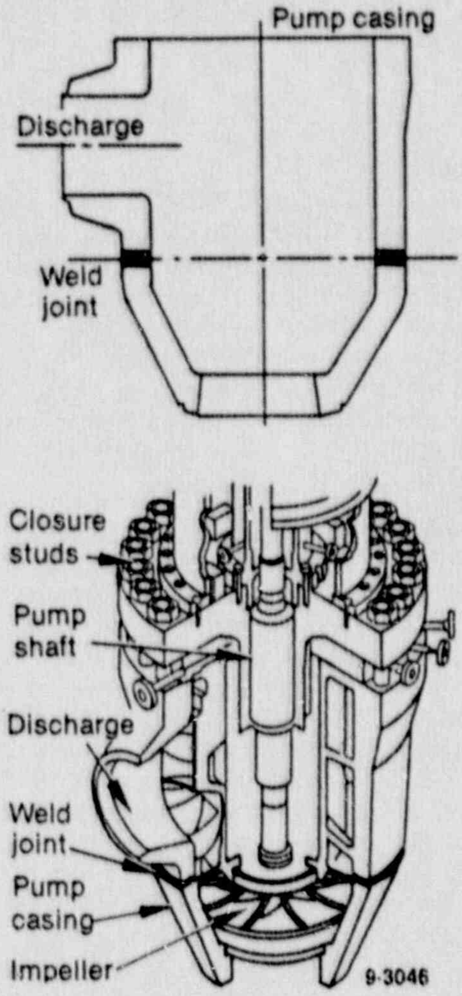

Figure 2.2. PWR Type F Coolant Pump.

The varied designs of reactor coolant pumps shown in Figures 2.1 through 2.4 are the result of the pump manufacturers' design philosophies (volute–type versus diffuser–based) and owners' design specification requirements. The actual design may vary somewhat from the ASME Section III types shown. However, the purpose of the ASME classification system is to provide both a pictorial and verbal description of the basic pump body geometries. Note that Figures 2.2 and 2.4 show the same general type of RCP (Type F). Compared to the PWR Type F design, the PWR Type E design shown in Figure 2.1 requires a smaller pump (primarily because of the structural reinforcement in the Type E design). Boiling water reactor Type C coolant pumps (Figure 2.3) are smaller than any of the PWR coolant pumps because of their lower system pressure and lower capacity (volume of liquid being moved) and because of the structural reinforcement obtained from splitter vanes in the Type C design; space requirements in BWR containments have also dictated this smaller design.

A compilation of PWR nuclear plants has been published with the NSSS vendor and RCP manufacturer identified;[3] Table 2.1 lists this information. The pump body geometry is the major difference in the designs supplied to the PWR and BWR NSSS vendors. The PWR Type F RCP bodies require a thicker pressure retaining wall, typically 100– to 200–mm (4– to 8–in.) thick. The BWR Type C and PWR Type E RCP bodies have thinner pressure retaining walls, typically 67– to 75–mm (2.5– to 3–in.) thick. The Type F pump walls are thicker because the casing walls are not structurally supported, whereas the Types C and E pump walls are stiffened by the integral volute and diffusers, which results in reduced thickness requirements. The massive size of the pump body is made necessary by the casting configurations and by the design considerations, including the close tolerances required by the pump internals.

In general, the RCPs used in nuclear power plants effectively combine metallic and nonmetallic

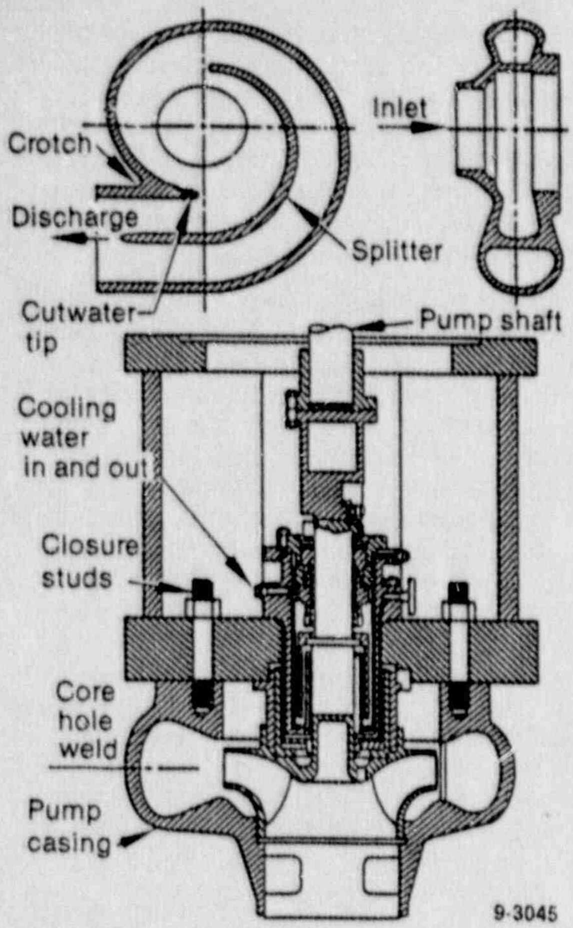

Figure 2.3. BWR Type C Coolant Pump.

components such as gaskets, seals, bearings, lubricants, and diaphragms. These components are required to maintain either an active function, such as rotation, or a passive function, such as prevention of pressure boundary leakage. Two concentric gaskets normally are used to seal the interface between the PWR coolant pump covers and bodies. A leak-off line is installed between the gaskets to detect any leakage of reactor coolant. Only one gasket is used in BWR coolant pumps. Leaking reactor coolant, if not checked, may cause corrosion of the closure studs, which are made of low-alloy steel. Reactor coolant pump main closure studs are long, [for example, 740 mm (29 in.) for Type E pumps][4] and their nominal diameter may vary from 90 to 140 mm (3.5 to 5.5 in.).

Historically, the design of RCPs has relied heavily on the accumulation of years of relatively trouble-free service at chemical, municipal, and industrial sites. In spite of the advances made in analytical techniques[5,6] and computer-based calculation methods, RCPs design for NSSS transients is conservative. This conservatism is due in part to the cast process used in manufacturing the pump body, which results in a thicker wall than generally required for the operating pressure conditions. Also, there have been no pressure retaining boundary leakage and/or cracking problems in castings and/or casting repairs or fabrication welds. This experience is based on nonnuclear as well as nuclear service. However, there have been leaks, caused by improperly maintained gaskets.

The pump designs also include the use of a thermal barrier and/or heat exchanger to limit the reactor coolant heat that reaches the mechanical seal cavity.[7] In the early Type E and C pumps, there was a mixing of cold cooling water (for protection of the mechanical seal) with reactor coolant water at the top of the thermal barrier. The resultant turbulent mixing condition caused cyclic thermal stresses to be induced at the pump shaft surface. This dynamic action typically occurred at a frequency of 1 to 25 Hz, and fatigue cracks were initiated. The issue is discussed below because it still may be a concern with some RCPs.

In summary, the RCP body is a critical license renewal component because of its pressure boundary significance. Difficulties encountered in replacing a pump body in a reactor coolant system (RCS) are also important license renewal factors. Although most of the pump internals (rotating elements, mechanical seals, etc.), and the closure studs, pump cover gasket, flywheel, and motor can be replaced easily, failure of some of these components could cause a partial loss of flow transient and, possibly, release of broken parts to the primary system and reactor. Therefore, any license renewal evaluation should also address these parts to ensure better plant reliability and safety. The pump body is the primary emphasis in this chapter, but later discussions include some other parts of the pump.

2.1.2 Reactor Coolant Pump Body Materials and Fabrication. The RCP bodies used in PWR and BWR plants are made of high-quality steels and are generally fabricated using a cast-weld process. The specific materials and fabrication processes used in constructing pump bodies are discussed in this section.

With one exception, all RCP bodies now in service in the United States were fabricated with statically cast austenitic stainless steel, either Grade CF-8 (comparable to wrought Type 304), CF-8M (comparable to wrought Type 316), or CF-8A. The one exception (which involves only three domestic plants) is the Combustion Engineering/Klein, Schanzlin, Becker forged carbon steel pump bodies used at Palo Verde 1,2,3—see Table 2.1. This pump body is a Type F design (see Figure 2.4) of similar size to

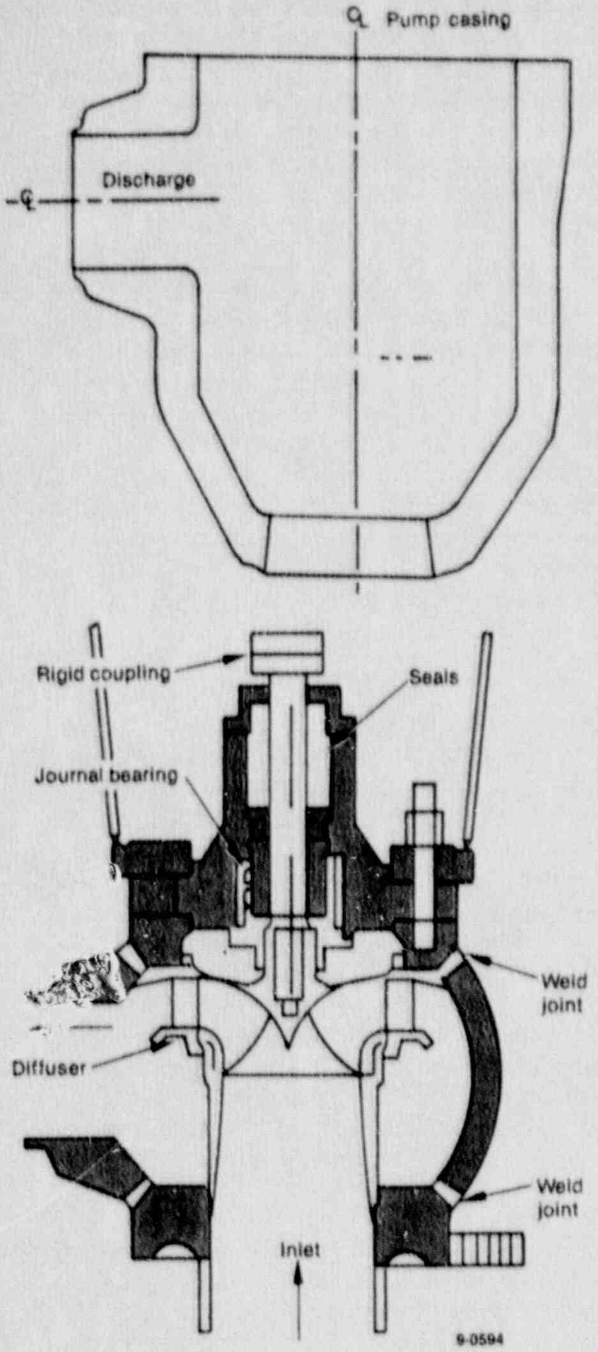

Figure 2.4. PWR Type F (Klein, Schanzlin and Becker) Coolant Pump.

cast-stainless-steel Type F pump bodies (Figure 2.2). The internal surface of the pump body is lined with a stainless-steel cladding deposited using a process similar to that employed on reactor vessels.[8] Thus, corrosion and fatigue issues should not be of any more concern than they may be in the reactor pressure vessel.

Because of the large pump size and the nondestructive evaluations (NDE) required by the ASME Code for PWR and BWR plants, casting of the pump body in one piece was replaced by a combined cast-weld fabrication process. However, later designs of Type F pump bodies were modified to decrease or eliminate the number of welds as it became practical to manufacture larger casting sections.[9]

Another important material parameter is the amount of delta ferrite in the RCP two-phase alloy castings. Although the ASME Code does not set forth delta ferrite requirements for cast-stainless-steel pump bodies, the Design Specifications and the pump manufacturers have historically worked to a 5% minimum [5 ferrite number (FN)] delta ferrite level. (The FN is approximately equivalent to the volume percentage of ferrite at low levels of delta ferrite.) The nominal ferrite level is approximately 9 FN, and ferrite levels greater than about 15 FN are avoided since they result in excessive foundry problems during the cooling and processing operations. Improvements in foundry melting practices, such as argon-oxygen-deoxidation (AOD) melting, allow for closer chemistry control and help to meet the 5 FN delta ferrite requirement. All base- material repair and fabrication welding has been performed with ferrite-controlled (>5 FN) weld filler metal as specified by the ASME Code (A-No. 8).

Most PWR (Type F) pump bodies were made using electroslag welding for the fabrication welds (owing to the circular geometry) with no postweld heat treatments; a postweld heat treatment is not an ASME Code requirement (nor is it prohibited) for stainless-steel welds. The Combustion Engineering/Klein, Schanzlin and Becker carbon-steel pump body requires a postweld heat treatment because of the section thickness. Without a postweld heat treatment, some high residual stresses (close to yield strength level) may be introduced into the heat-affected zones near the weldments in Type F pump bodies. Fabrication welds in all Type E (PWR) and Type C (BWR) pump bodies are manual welds followed by full solution heat treatment of the completed cast-weld fabrication. This treatment eliminates the residual welding stresses but introduces residual stresses caused by water quenching from the solution annealing temperature [~1038 to 1149°C (1900 to 2100°F)]. To minimize changes in the machining tolerances during plant service, one vendor has applied a low-temperature thermal-stabilizing treatment [at approximately 399°C (750°F)] to their Type F pump bodies before machining.

The location of fabrication welds on Type C, E, and F pump bodies are shown on the weld maps supplied

Table 2.1. U.S. PWRs listed by NSSS vendor with the RCP manufacturer identified[3]

Westinghouse[a]	Combustion Engineering[b]
Beaver Valley 1,2	Arkansas Nuclear One 2
Braidwood 1,2	Calvert Cliffs 1,2
Byron 1,2	Fort Calhoun
Callaway 1,2	Maine Yankee
Catawba 1,2	Millstone 2
Comanche Peak 1,2	Palisades
Cook 1,2	San Onofre 2,3
Diablo Canyon 1,2	St. Lucie 1,2
Farley 1,2	Waterford 3
Ginna	
Haddam Neck	Palo Verde 1,2,3[c]
Harris 1	
Indian Point 2,3	**Babcock and Wilcox**
Kewaunee	
McGuire 1,2	Arkansas Nuclear One 1[d]
Millstone 3	Crystal River 3[d]
North Anna 1,2	Davis Besse[d]
Point Beach 1,2	Oconee 1[e]
Prairie Island 1,2	Oconee 2,3[f]
Robinson 2	Rancho Seco[f]
Salem 1,2	Three Mile Island 1[e]
San Onofre 1	
Seabrook 1	
Sequoyah 1,2	
South Texas 1,2	
Summer	
Surry 1,2	
Trojan	
Turkey Point 3,4	
Vogtle 1,2	
Watts Bar 1,2	
Wolf Creek	
Zion 1,2	
Yankee Rowe	

a. All have Westinghouse RCPs.

b. All have Byron Jackson RCPs except Palo Verde, which is Klein, Schanzlin, and Becker.

c. Klein, Schanzlin, and Becker.

d. Byron Jackson.

e. Westinghouse.

f. Bingham–Willamette.

with the document packages that accompany each pump body. The document package, in accordance with the ASME Code, supplies the utility with all pertinent Quality Assurance (QA) documents and also is the information source for inservice inspection of the fabrication, attachment, and repair weld locations. The delta ferrite in cast stainless steel improves the resistance to stress corrosion cracking under both the solution annealed and sensitized conditions (compared with wrought stainless steel). Solution annealed material is preferred over sensitized cast stainless steel in terms of both corrosion cracking resistance and ductility loss. To minimize sensitization and residual stresses in Type E and C pumps, all welding performed after the solution heat treatment of the material is limited to a low-heat input no greater than 19,700 J/cm (50,000 J/in.).

Section III of the ASME Code requires that a delta ferrite determination be performed for A-No. 8 weld filler metal. The delta ferrite determination is performed by either magnetic measuring instrumentation or by use of chemical analysis in conjunction with a delta ferrite table. The minimum delta ferrite must be 5 FN, as stated above. The use of a controlled delta ferrite filler weld metal has helped to reduce the risk of a depleted region of delta ferrite near a weld fusion line; depleted ferrite may lead to susceptibility of stress corrosion cracking. Delta ferrite determinations for the cast-stainless steel pump casings have historically been based on chemical analysis.

2.1.3 Coolant Pump Shaft Material and Fabrication. The RCP shafts are made of Type 304 or 316 stainless steel and are generally forged in one piece by a swagging process. A full solution heat treatment is applied by first heating the shafts while held vertically to 1150°C (2100°F), then quenching them from this temperature. Some shafts are chrome plated [plating thickness 0.075 mm (0.003 in.)] to minimize susceptibility to galling during shrink fits. The typical length of a shaft is about 1.8 m (6 ft), and the diameter at the upper end near the coupling is 102 to 127 mm (4 to 5 in.), whereas the diameter at the lower end near the impeller is 203 mm (8 in.). The impellers are made of cast material and bolted to the shaft in the older designs, whereas in newer designs the impellers are welded to the pump shafts with full penetration circumferential welds.

2.1.4 Other Pump Component Materials. Most of the other pump parts, including the pump cover, are made of Type 300 stainless steels. The mechanical seals are also generally austenitic stainless steel with a carbide facing for rotating contact and high-purity graphite for stationary contact. O-rings are generally made of nitrile rubber. The pump-to-cover gaskets are typically made of Type 304 stainless steel flexitallic (stainless steel- graphite asbestos material), and the pump cover fasteners are made of low-alloy steel, either SA540 Grade B23 or SA193 Grade B7 bolting material.

2.2 Stressors

The normal plant operating (steady-state) and transient stresses are important stressors to the pump casing. Other important stressors include long-term thermal exposures, residual stresses, and high-cycle fatigue stresses caused by pump rotations. In the earlier Type E and C pumps, there is hot and cold water mixing at the thermal barrier, which can create high-cycle (1 to 25 Hz) thermal stresses in the pump shaft and cover components. Thus, cyclic mechanical and thermal loading and long-term thermal exposure of the RCP body casting are of most concern with regard to license renewal.

2.3 Degradation Mechanisms and Sites

Several mechanisms are discussed in this section that tend to reduce the life of pump components in a general sense. The most important degradation processes are rated and summarized later.

2.3.1 Thermal Embrittlement. Cast stainless steels, that is, Grades CF-8, CF-8M, and CF-8A, have austenitic-ferritic microstructures and are subject to degradation by thermal embrittlement. Thermal embrittlement of the base metal results in a slow loss of fracture toughness over extended periods of time and is influenced by coolant temperature and time of exposure at temperature. The thermal embrittlement rate is the highest at about 475°C (885°F), but significant embrittlement also occurs at PWR and, to a lesser extent, BWR operating temperatures. In addition, thermal embrittlement is influenced by the base metal's chemical composition, volume fraction of ferrite, and ferrite distribution (spacing) in the microstructure. The ferrite distribution in statically cast, thick-wall, stainless-steel components is not uniform. The loss of material toughness is caused by the formation of an alpha-prime phase in the ferrite. Since only the ferrite phase is embrittled by long-term exposure at LWR operating temperatures, the higher the percentage of ferrite, the greater the embrittlement. The delta ferrite range for reactor coolant pump bodies has historically been bounded by a 5% minimum. Generally, measured ferrite levels average about 9% but can go up to about adequate, since fracture toughness after aging is still maintained at generally acceptable values. Investigations into thermal embrittlement effects, using fracture mechanics methods at low deformation rates (approximately five orders of magnitude lower than those used in impact testing), show that the embrittlement problem does not seem to compromise the safety and integrity of the reactor coolant pump body materials.

The welds in the pump body are not very sensitive to thermal embrittlement. Although, the initial toughness of the welds in the pump body is significantly lower than that of the unaged base metal, the ferrite content of the welds is generally lower than that of the base metal. In fact, the pump body fabrication welds, repair welds, and field-assembly welds in several older plants may have had less than 5% ferrite.[10,a] The ASME Code (Section III) did not have ferrite requirements for austenitic stainless steel welds prior to 1971, whereas in newer plants a minimum of 5% ferrite in the weld materials is required by the Code.[10] The minimum ferrite content requirements help prevent microfissuring in the welds.

Laboratory tests show that the loss of toughness in thermally aged cast stainless-steel components can be recovered by annealing at 550°C (1022°F) for one hour, followed by rapid cooling (quenching) to lower temperatures.[11,b] The short-term annealing process dissolves the alpha-prime phase. However, rapid heating and cooling of the pump body is not feasible, and slow heating and cooling to and from the annealing temperature will cause formation of several other phases in the ferrite, resulting in additional loss of toughness. Therefore, annealing of aged cast stainless-steel components is not an acceptable solution; in addition, for pumps, which have close tolerances, a high temperature anneal would be unacceptable because of the potential for distortion.

2.3.2 Fatigue. Light water reactor pump bodies are subject to thermal and mechanical fatigue damage caused by the system operating transients and pump vibrations. The welds in Type F pumps (such as the electroslag welds) are susceptible to fatigue damage because of the high residual stresses. The susceptible sites for fatigue damage in the Types C and E pumps are likely to include some portion of both the base metal and weld region, because of the geometric configuration and complex weld design and the associated residual stresses caused by fabrication. Figure 2.1 shows the locations of the maximum stress intensities in Type E pumps.[9] In addition, the ferrite content in the welds (including field assembly welds) may be low (<3%) in some older plants, and microfissures may be present. Microfissures can adversely affect the fatigue strength of thermally embrittled pump castings. However, RCP body fatigue damage is expected to be quite small in the absence of microfissures because the pump bodies have a thickness greater than that required for structural integrity to ensure dimensional stability for the rotating components.

If there are any flaws or defects in the cast stainless steel pump bodies, they were introduced during manufacture of the castings, and resulted from shrinkage during solidification. Flaws located on the surface of the pump bodies are subject to crack growth rates greater than those of subsurface flaws if high stresses are present; the crack growth rate can be further increased by exposure to the reactor coolant. Forged carbon steel pump bodies are also subject to increased crack growth rates if flaws located on the surface of the stainless steel cladding expose the base metal.

Light water reactor pump shafts are susceptible to high-cycle, mechanical and thermal fatigue damage caused by alternating mechanical bending stresses and also by the rapidly varying thermal stresses in the thermal barrier region.[c] The bending stresses are caused by any asymmetric distribution of the static pressure.[12] These alternating bending stresses, along with any stress raisers and high residual stresses at the local welds on the shaft surface, can initiate circumferential cracks and propagate them in a plane perpendicular to shaft axis. These cracks usually occur in grooves on the shaft surface and propagate in a transgranular manner.[13]

The rapidly varying thermal stresses are caused by the turbulent mixing of the hot reactor coolant with the component cooling water, which is normally at a temperature of about 50°C (120°F). Thermal fatigue cracks have been found in both PWR and BWR (Type E and Type C) pump shafts. The susceptible sites are the square threads in the thermal barrier region and the shaft immediately adjacent to the threads. The thermal stresses in the thread region are in the hoop direction and, therefore, fatigue cracks in the axial direction have been observed. The thermal

a. E. Landerman, private communication, Westinghouse, Pittsburgh, Pennsylvania, September 1988.

b. W. J. Shack, private communication, Argonne National Laboratory, Chicago, August 1988.

c. Byron Jackson Pump Division, private communication, Borg Warner Corporation, 1987.

stresses in the smooth portion of the shaft are both axial and in the hoop direction, and the resulting fatigue cracks have a random pattern. Thermal fatigue cracking will be self limiting in the absence of any mechanical loads. Mechanical bending loads cannot propagate axial cracks, but there is a potential that an axial crack may change its orientation and become a circumferential crack,[13] which can be propagated by mechanical bending loads; at least one such failure has occurred in Europe.

A coolant pump shaft at Crystal River 3 completely failed in 1986.[14,15] The cause of failure was determined to be a circumferential crack attributed to fatigue. The crack initiated at a groove in the shaft, which acted as a stress raiser. The same pump experienced a significant change in vibration response in 1988 (recorded by the shaft vibration monitoring probes).[16] The most likely cause of this change has been determined to be a circumferential crack in approximately the same location as the 1986 event. The contributors to this failure appear to form a common set of conditions leading to failure. They include (a) a shaft resonance near twice operating speed, (b) asymmetry of the shaft, (c) radial sideloads, and (d) reduced shaft endurance limits caused by shrink-fitted components on the shaft. Some causes of these conditions may be grooves, splines, and threads on the shaft; material discontinuities under shrink-fit components; chrome plating on the shaft surface; poor or improper welding; loose impeller bolts; and improper pumping loads.[16] Hairline cracks have been found in the Type F pump shafts at the Palo Verde 1 plant. Heat-induced stress and the shaft's chrome plating have been mentioned as factors causing the cracks.[17]

2.3.3 Boric Acid Corrosion. PWR pump body closure studs are susceptible to corrosion wastage caused by primary coolant leakage across the pump body-to-cover gasket. Corrosion wastage is a special case of severe corrosion. Leakage and evaporation of the boron containing primary coolant water leaves a concentrated boric acid solution in contact with the closure studs. Concentrated boric acid solutions corrode ferritic steel easily. Without a concentrated boric acid solution the ferritic steel closure stud corrosion would be minimal. Primary coolant leakage has caused significant corrosion damage to pump body closure studs (it may also cause corrosion of the base metal of carbon steel pump bodies).[18] Boric acid corrosion in one PWR plant reduced seven reactor coolant pump studs from a nominal diameter of 90 mm (3.5 in.) to between 25 and 37 mm (1.0 and 1.5 in.).[4] The corrosion occurred in the regions of the studs adjacent to the top surface of the lower flange. Visual inspection revealed that the severely corroded studs had an hour-glass appearance. Visual inspection of closure studs at other PWR plants has revealed that the studs in all pump designs are susceptible to boric acid corrosion. These problems can be controlled by monitoring the leak-off lines and repairing the gaskets when leakage is detected. Unfortunately, the leak-off lines have become plugged at some plants and are not always instrumented. Installation of instrumentation for monitoring the leak-off lines between the gaskets is necessary.

The major causes of gasket leakage are poor maintenance, minor corrosion of the stainless steel portion of the gasket, and poor gasket spring-back.[19] Gasket leakage is usually associated with an uncleaned (dirt and nicks) or damaged gasket seating area caused by improper reassembly. Implementing the following recommendations will upgrade the maintenance procedures for the closure studs and, thus, improve plant reliability: use gaskets with improved spring-back characteristics, control cleanliness during gasket installation, and use proper fastener lubrication and tensioning practices.

2.3.4 Stress Corrosion Cracking. Cast stainless steel pump bodies and their welds have excellent resistance to stress corrosion cracking. Generally, the ferrite content in the welds is >5%. However, if very low levels of ferrite are present in any of the welds because of the filler material and weld procedures used, those welds could be sensitized and become susceptible to environmentally induced stress corrosion cracking.[20] The Types E and C pump bodies receive a full solution heat treatment which reduces the sensitization in their welds. However, any improvement provided by solution heat treating will be limited because the sections of the body are thick. The optimum improvement will be at and near the surface, because the cooling rate is an important factor. Repair welding performed after the full solution heat treatment of the bodies has generally been limited to a low-heat input, no greater than 1970 J/mm (47.4 Btu/in.). This practice prevents additional sensitization and also reduces residual stresses. Thus, the susceptible sites in the Types E and C pump bodies will be at the welds connecting the pump body to the reactor coolant piping, if the ferrite content of the connecting welds is very low.

Leakage of reactor coolant across the pump body-to-cover gasket may wet the insulation, leaching chlorides out of the insulation. This chloride contamination increases the potential for stress corrosion cracking in the pump body. If the insulation meets chloride concentration acceptance criteria, the chloride contamination will be minimized.[21]

2.4 Potential Failure Modes

Based on best information to date, the RCP body castings are considered the most critical pump component with regard to license renewal. The most likely failure mode for a pump casting would be through–wall leakage of primary coolant water. In the unlikely event that thermal embrittlement (long–term aging) ever becomes a problem, unstable ductile tearing of the pump body during a design transient would be a potential failure mode. The RCP body fatigue life is usually very conservative and is not considered to be a limiting factor for any license renewal.

The degradation of the pump closure fasteners caused by borated water corrosion will not lead to the failure of cast stainless steel pump bodies but will cause corrosion of carbon steel pump bodies, and the problem must be addressed. The primary cause of fastener wastage is poor maintenance. Without reactor coolant leakage across the gasket, no significant corrosion would occur. The pump manufacturer, the utilities, and the regulatory agencies are aware of the gasket problem and corrective actions are being taken, such as (a) gasket material changes (generally proprietary), (b) improvement in assembly procedures, and (c) better housekeeping practices. No fatigue or stress corrosion bolt failures have been reported.

Failure of a pump shaft will not compromise the integrity of the pressure boundary, but it will result in a shutdown of the pump and a forced system outage. Cracks caused by thermal mixing and the resulting alternating thermal stresses cannot be predicted from operating histories or from accumulated operating time. Calculations show that axial cracks in a pump shaft will propagate slowly or may be arrested completely.[12] However, the thermal cracks could ultimately result in shaft failure, depending on design details or if unusual operating conditions are experienced; at least one failure has occurred in Europe.

Failure of pump internals, for example, shafts and bearings, will not compromise the integrity of the pressure boundary, but the broken pieces may be carried over to the reactor vessel and damage the vessel internals, fuel rods, and other core components. Generally, such failures have resulted in a shutdown of the pump and a forced system outage. However, in one recent event in a foreign BWR plant, broken pieces of a recirculation pump internal component were carried over to the reactor pressure vessel.[22,23] The recirculation pump developed wild vibrations because the failure occurred while the plant was running at 90% of full power.

The failure resulted from deficiencies in the welding of a bearing housing component and it is likely to have been caused by fatigue. The welds had not been inspected for cracks prior to failure, even though weld failure in a similar pump in another BWR plant had occurred earlier. At least 10 fragments of broken pump were at the bottom of the reactor vessel, and 13 more inside the jet pump. The utility plans a thorough inspection of all the fuel rods (more than 48000 rods), and complete checkout of the entire plant system. The recirculation pump was designed by Byron–Jackson but fabricated and assembled by another company. All pumps with a weld design similar to that of the failed pump are susceptible to this failure mode.[24]

2.5 Inservice Inspection and Surveillance Requirements

2.5.1 Pump Body. Generally, at least one reactor coolant pump from the RCS is disassembled for inspection and maintenance at the end of each inspection interval. Inservice inspection requirements for the pump body include surface and volumetric examination of identified repair and fabrication welds. The cast stainless steel pump bodies are difficult to inspect with conventional ultrasonic testing methods because of the elastic anisotropy caused by the different grain structures in the castings and because of the severe attenuation of the ultrasonic wave caused by the coarse grains in the steel. Therefore, radiography is generally used for volumetric examination of cast stainless steel pump body welds. In accordance with ASME Code Section XI, any indication detected by radiography must be considered a worst–case flaw, because normal radiography can only detect the presence of a flaw, not its location or size (a worst–cast flaw is a surface flaw with an aspect ratio of 0.5). However, triangulation radiography may be used to characterize, size, and locate a flaw.

The extent of the thermal embrittlement of cast stainless steel components may be such that the critical flaw size decreases to the size of an existing flaw, or the critical flaw size may become too small to reliably detect using current inservice inspection methods. However, advanced ultrasonic testing (UT) methods are being developed that can better detect flaws and determine their size, orientation, and location.[20,25]

These advanced UT methods will be more effective than radiography.

The acceptance standards for the allowable length of the surface and subsurface flaws in light water reactor pump body welds are given in Table IWB-3518-2 of ASME Code, Section XI; the allowable surface flaw length is less than half the allowable subsurface flaw length.[26] Similar standards for allowable flaws in cast stainless steel base metal are needed. These standards should take into account degradation caused by thermal embrittlement.

The inservice inspection requirements were originally developed for Type F pump bodies, which have high residual stresses at the welds and low stresses in the base metal. However, these requirements are also applied to Type C and E pumps, which have geometric configurations and stress distributions different from that of the Type F bodies. High stress intensities are present at both welds and base metal of Type C and E pump bodies.

As discussed previously, a reactor coolant leak across the pump body-to-cover gasket can make adjacent areas of the pump body susceptible to stress corrosion cracking. Damage to the affected area can be detected by penetrant testing.

2.5.2 Pump Shaft. LWR coolant pumps are generally equipped with two monitors mounted at the top of the motor stand in a horizontal plane to detect radial vibrations of the pump. Monitoring of pump motor frame vibrations has been successfully used to detect damage to the pump shaft.[12,15] Proximity probes have also been used for vibration monitoring to detect circumferential cracks in the pump shaft. However, vibration monitoring will not be able to detect axial cracks caused by thermal fatigue.

The inspections done during shutdown should include surface and volumetric examinations of the pump shaft. Several utilities have used the conventional UT technique to inspect pump shafts, but the results have been inconclusive and misleading. A new UT technique, the modified cylindrically guided wave technique, is being developed by the Southwest Research Institute for shaft inspection, and the initial results of its use are promising.[27,28]

2.5.3 Pump Closure Studs. ASME Section XI requires volumetric examination of all the bolts, studs, nuts, and bushings during each inspection interval. However, the conventional UT volumetric examination techniques do not effectively measure stud corrosion wastage.[29] Therefore, the ASME inservice inspection requirements, which are currently limited to volumetric examinations, should be revised to include visual examinations. Removal of the insulation covering the studs will facilitate visual examinations to determine whether reactor water leakage has caused corrosion of the studs. It may also be necessary to either remove the bolt for inspection or consider a leak-before-break analysis.[19] ASME Section XI requires examination of the flange surfaces when a mechanical joint is disassembled. Use of the cylindrically guided wave technique developed by the Southwest Research Institute might also be considered, because it is capable of detecting both flaws and corrosion wastage in the long studs.[30]

2.6 Summary, Conclusions, and Recommendations

Table 2.2 summarizes the stressors, degradation sites and mechanisms, and potential failure modes for LWR primary coolant pump bodies, closure studs, shafts, and internal welds. The conclusions and recommendations related to aging degradation of these components are as follows:

1. A model should be developed for estimating the decrease in fracture toughness (thermal embrittlement) of cast stainless steel pump bodies as a function of coolant temperature, time of exposure at temperature, chemical composition, and ferrite content and its spacing in the microstructure.

2. Because the ferrite distributions through statically cast, thick-wall, stainless steel components are not uniform, data for the actual ferrite distributions in pump bodies are needed. Such data will make it possible to more accurately determine the degree of thermal embrittlement.

3. Thermal embrittlement may be such that an existing flaw can reach critical dimensions, leading to failure of the body. Characterization of any flaws would help efforts to evaluate the continued structural integrity of the pump body. Advanced ultrasonic testing methods and radiography methods are needed for this purpose.

4. Standards for allowable flaws in the cast stainless steel base metal are needed. These standards should take into account degradation

Table 2.2. Summary of degradation processes for LWR coolant pumps

Rank	Degradation Sites	Stressors	Degradation Mechanism	Potential Failure Modes	ISI Methods
1	Pump body (casting)[a]	Temperature, system operating transients	Thermal embrittlement, fatigue	Through–wall leakage, unstable ductile tearing	Surface, volumetric, suggest surveillance program
2	Closure studs	Gasket leakage (borated water), mechanical and thermal stresses	Corrosion, wastage	Leakage, breakage	Surface, volumetric, visual (including gaskets)
3	Pump shaft	Thermal stresses (mixing of hot and cold coolants)	High cycle, mechanical and thermal fatigue	Breakage (contained by pump body)	Surface, volumetric
		Mechanical bending stresses (caused by shaft rotations)			
4	Fabrication welds (pump internals)	Mechanical and thermal stresses	Fatigue	Breakage (broken pieces may be carried over into reactor pressure vessel)	None required

a. Wrought carbon steel pump bodies make up a very small percentage of those in the field and have not had a long enough service history to be reflected here.

caused by thermal embrittlement. ASME Section XI, Table IWB-3518-2, provides similar standards for allowable planar flaws in cast stainless steel pump body welds.

5. Annealing of aged pump bodies is not an acceptable method for restoring material toughness. This process causes formation of several other phases in the ferrite, resulting in additional loss of toughness. In addition, annealing could distort the very close tolerances associated with pumps.

6. The ferrite content in the pump body welds should be determined. Welds with low levels of ferrite may be susceptible to stress corrosion cracking, especially if the body is not subjected to a heat treatment after welding.

7. Welds in Type F pump bodies and high-stress regions in Types C and E pump bodies may be susceptible to fatigue damage. In addition, the presence of any microfissures in low- ferrite (<3%) welds may adversely affect the fatigue strength of the pump body and should be taken into account in estimates of fatigue damage.

8. The ASME Section XI inservice weld inspection requirements were originally developed for the Type F pump bodies, which have high residual stresses at the welds. However, these requirements may not be practical or meaningful for Types C and E pumps. The high stress intensity regions in Types C and E pumps are likely to include some portion of both the base metal and weld. Surface examination of the high stress intensity regions is recommended.

9. Failure of the internal attachment welds may result in broken pieces of pump internal components carried over to the reactor pressure vessel and damage of vessel internals and core components. Weld inspection guidelines for the various pump designs need to be developed.

10. Leakage of borated water across LWR primary coolant pump case-to-cover gaskets can cause corrosion of the pump closure studs and corrosion of carbon steel pump body base metal. Corrective actions to prevent leakage include use of gaskets with better spring-back characteristics, proper gasket installation and cleanliness control, and proper stud tensioning practices. The leak-off lines between the inner and outer gaskets should be left unplugged and be instrumented so that leakage can be detected.

11. Volumetric examination of the closure studs, as presently required, should be supplemented with visual examinations to determine whether leakage has occurred. The use of the cylindrically guided wave technique should be considered. Another option would be to consider a leak-before-break analysis to evaluate closure integrity.

12. Use of conventional ultrasonic techniques to inspect pump shafts gives inconclusive and misleading results. A field evaluation of the modified cylindrically guided wave technique for shaft inspection is needed. Monitoring of the pump motor frame vibrations is recommended. Such monitoring can detect a circumferential crack in the pump shaft.

2.7 REFERENCES

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3. PRESSURIZED WATER REACTOR PRESSURIZER

A. G. Ware

The pressurizer is a major component of each pressurized water reactor (PWR) reactor coolant system (RCS) and, as its name suggests, its primary purpose is to control system pressure. Boiling water reactors (BWRs) do not have pressurizers. Pressurizers are similar in some respects to the other major RCS pressure vessels, the steam generator and the reactor pressure vessel, in that they are a part of the primary coolant system pressure boundary designed and built to the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code).[1] A failure can result in an unisolatable leak and boric–acid corrosion of the base metal. However, unlike the reactor pressure vessel, the pressurizer is not in a region of high neutron fluence and, thus, is not susceptible to brittle fracture. Also, unlike the steam generator there are no thin–walled heat transfer tubes that have shown a history of corrosion and wear problems. However, the pressurizer does have a number of design features unique to its functional purpose that should be addressed as part of the license–renewal process.

This chapter describes the factors affecting life extension of the pressurizer and its subcomponents but does not comprehensively cover the associated primary system piping (such as the surge, spray, drain, or vent lines, for which the discussions in Chapter 5 of Volume 1[2] and Chapter 4 of this volume are applicable) except for the safe–end welds, which will be discussed. Nuclear power plant valve reliability is an ongoing problem throughout plant life, whether for 10, 20, 40, or more years. Pressurizer relief valves have been especially troublesome, as they have occasionally failed to reseat properly (such as occurred in the TMI–2 accident) and set points have drifted out of adjustment. However, since these valves are relatively easy to repair or remove and reinstall, compared with overall pressurizer replacement, they are not considered a major–license renewal concern (though they are a major plant safety concern). Therefore, the associated valves (such as pressure relief, surge, and spray lines) will not be discussed in this chapter.

The designs of the older vintage Babcock & Wilcox, Combustion Engineering, and Westinghouse Electric Company (Westinghouse) PWRs will be reviewed in this chapter. However, pressurizer design changes over the years have been minimal, and, thus, the discussions in this chapter will apply to newer pressurizers as well.

3.1 Description

The pressurizer maintains RCS pressure within a given operating band, compensates for RCS volume changes during reactor power level adjustments, and provides a means for overpressure protection through safety and relief valves. An elevation view of the pressurizer with respect to other major RCS components is shown in Figure 3.1 for a Babcock & Wilcox PWR, and a schematic of the pressurizer system for Westinghouse four–loop plants is shown in Figure 3.2.[3] The arrangement of the pressurizer in the primary system is typical of that for plants designed by all three PWR vendors, except that the Babcock & Wilcox spray line is fed from only one RCS cold leg, whereas the Combustion Engineering and Westinghouse designs are connected to two of the cold legs.

The Babcock & Wilcox,[4,5] Combustion Engineering,[6,7] and Westinghouse[8,9] pressurizer designs for typical pre–1970 plants are shown in more detail in Figures 3.3, 3.4, and 3.5. Each vendor manufactured its own pressurizers. All designs have the same basic configuration, that of a vertically mounted, bottom–supported, tall and slender cylindrical pressure vessel with top and bottom heads (in most cases hemispherical). However, the standard Babcock & Wilcox pressurizer, with a volume of 42.5 m^3 (1500 ft^3), is generally smaller than that of the other two vendors, 51.0 m^3 (1800 ft^3) for standard Westinghouse and Combustion Engineering designs, though there are exceptions; the Combustion Engineering Maine Yankee pressurizer volume is 42.5 m^3 (1500 ft^3), and the Westinghouse H. B. Robinson and Turkey Point 3 and 4 volumes are only 36.8 m^3 (1300 ft^3). Safety concerns have been raised over the smaller pressurizers, because their volumes cannot accommodate transients as well as larger pressurizers.[10] This is a design and operational question, however, rather than a plant aging issue.

Although the overall pressurizer basic designs are very similar, a number of individual variations may be found from plant to plant. While the dimensions given in this section are intended to be typical, they are by no means applicable to all plants.

The vessels are made of low–alloy steel, with austenitic stainless steel or Ni–Cr–Fe cladding [typically 0.48– to 0.96–cm (0.19– to 0.38–in.) thick] on all surfaces in contact with the primary coolant. The shell is

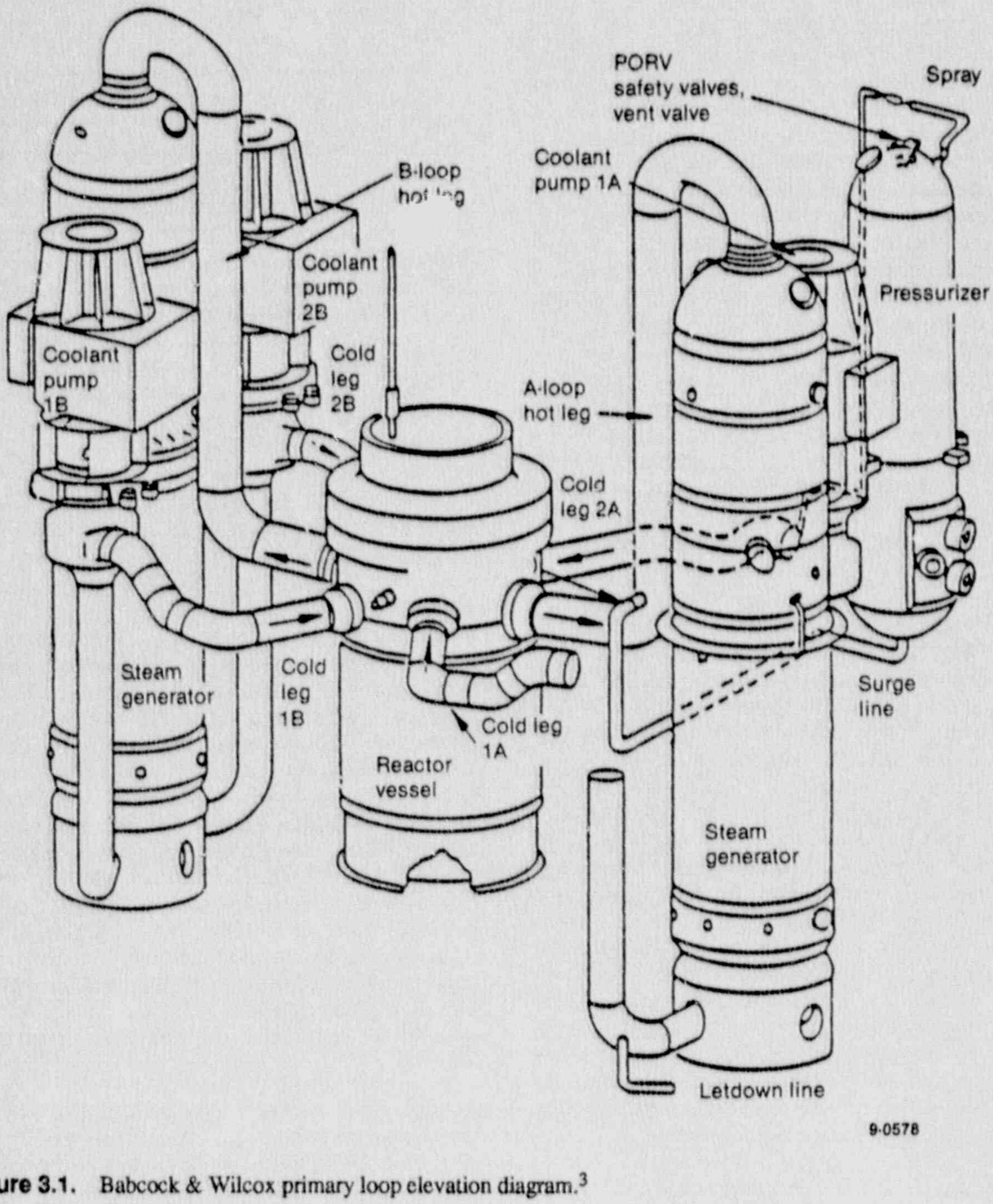

Figure 3.1. Babcock & Wilcox primary loop elevation diagram.[3]

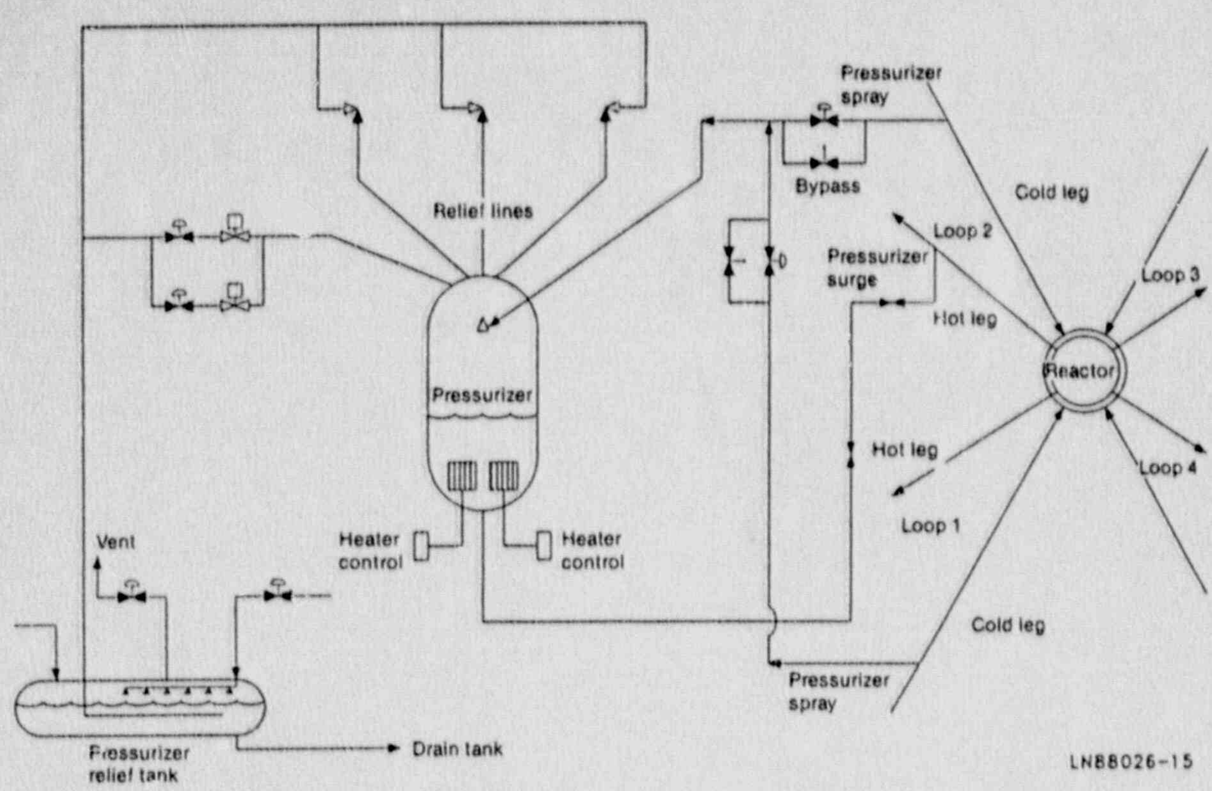

Figure 3.2. Westinghouse pressurizer system.

fabricated from sections of formed plate. As an example, Combustion Engineering pressurizer shells were manufactured from two plates that were hot pressed to form two 180–degree cylindrical sections, which, after heat treatment, were then longitudinally welded together to form a complete cylindrical shell.[a] Babcock & Wilcox shells were made from two 180–degree sections longitudinally welded together to form a cylinder or from two such cylinders with a central girth weld.[b] Top and bottom hemispherical heads were constructed by pressing either sections of plates[a] or complete circular plates,[11] by spinning,[b] or by casting.[c] The heads are welded to the cylindrical shell at the manufacturing shop, and the complete pressurizer is shipped as a unit, so that the only field welds required are for the piping connections. Stainless steel surge and spray piping must be welded to a carbon–steel nozzle, so a "safe end" weld is used. Safe ends (see Figure 3.6) are transition sections that are used to avoid welding between dissimilar materials in the field.

Under normal operating conditions, the pressurizer is 50 to 60% full of water that is covered by a steam bubble. The water and steam regions are denoted in Figures 3.3 through 3.5.

The pressurizer is supported both vertically and horizontally at the bottom, in some cases by a support skirt and in other designs by a ring girder. The vessel is also restrained horizontally at either one or two elevations on the exterior of the shell in order to resist design–basis earthquake loads. These supports are weldments, keys welded to the upper vessel (Combustion Engineering), or shear lugs (Westinghouse), which allow the pressurizer to expand radially and vertically but resist torsional and translational movements. A Westinghouse support arrangement is shown in Figure 3.7.

Electrical heaters are located at the bottom of the pressurizer vessels. They are single–unit, sheath–type immersion heaters,[7] which protrude through the

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a. J. Sodergren, private communication, Combustion Engineering, Chattanooga, Tennessee, December 12, 1986.

b. R. Douglas, private communication, Babcock & Wilcox, Barberton, Ohio, December 16, 1986.

c. V. V. Miselis, private communication, Westinghouse, Pittsburgh, Pennsylvania, December 11, 1986.

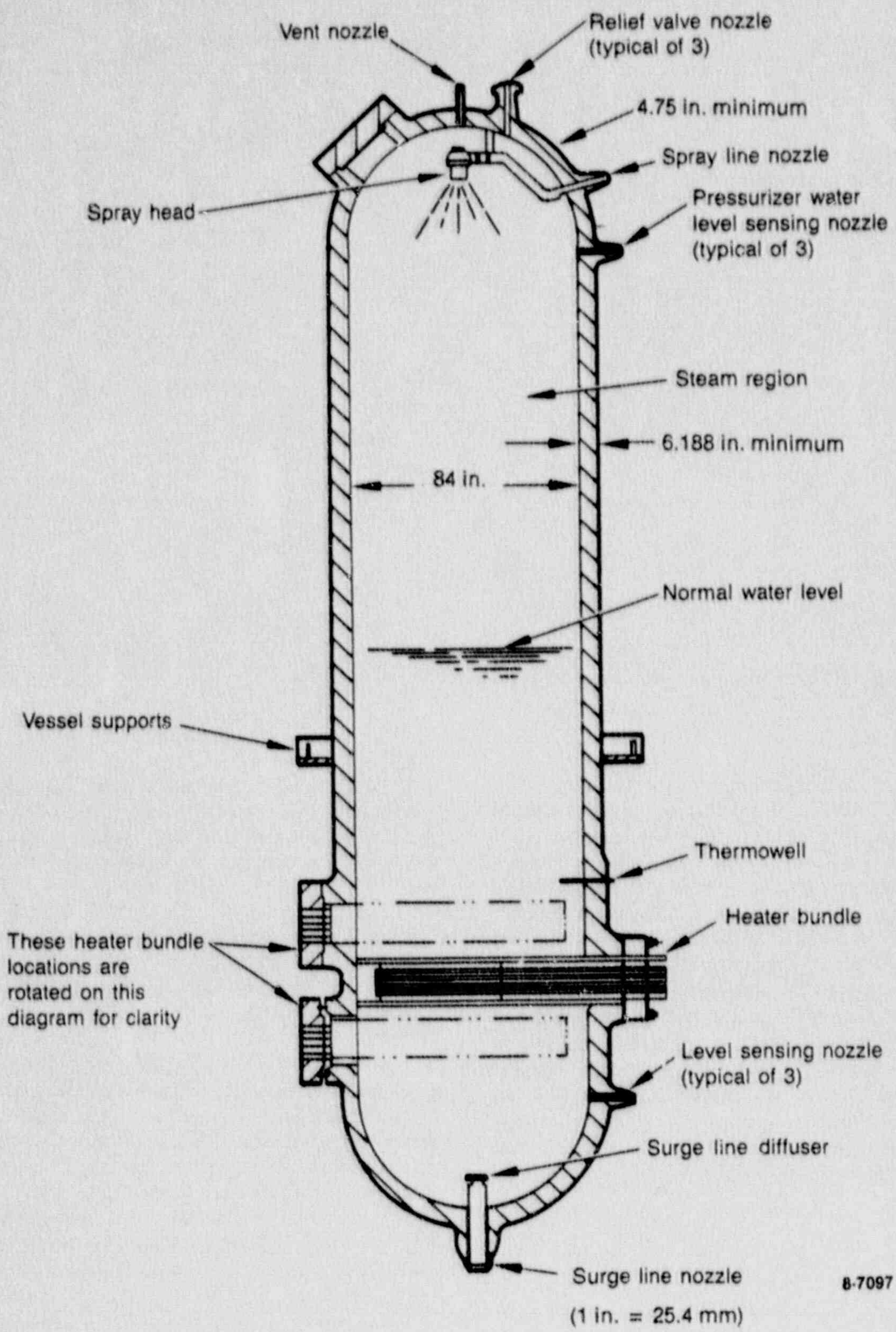


Figure 3.3. Babcock & Wilcox pressurizer.

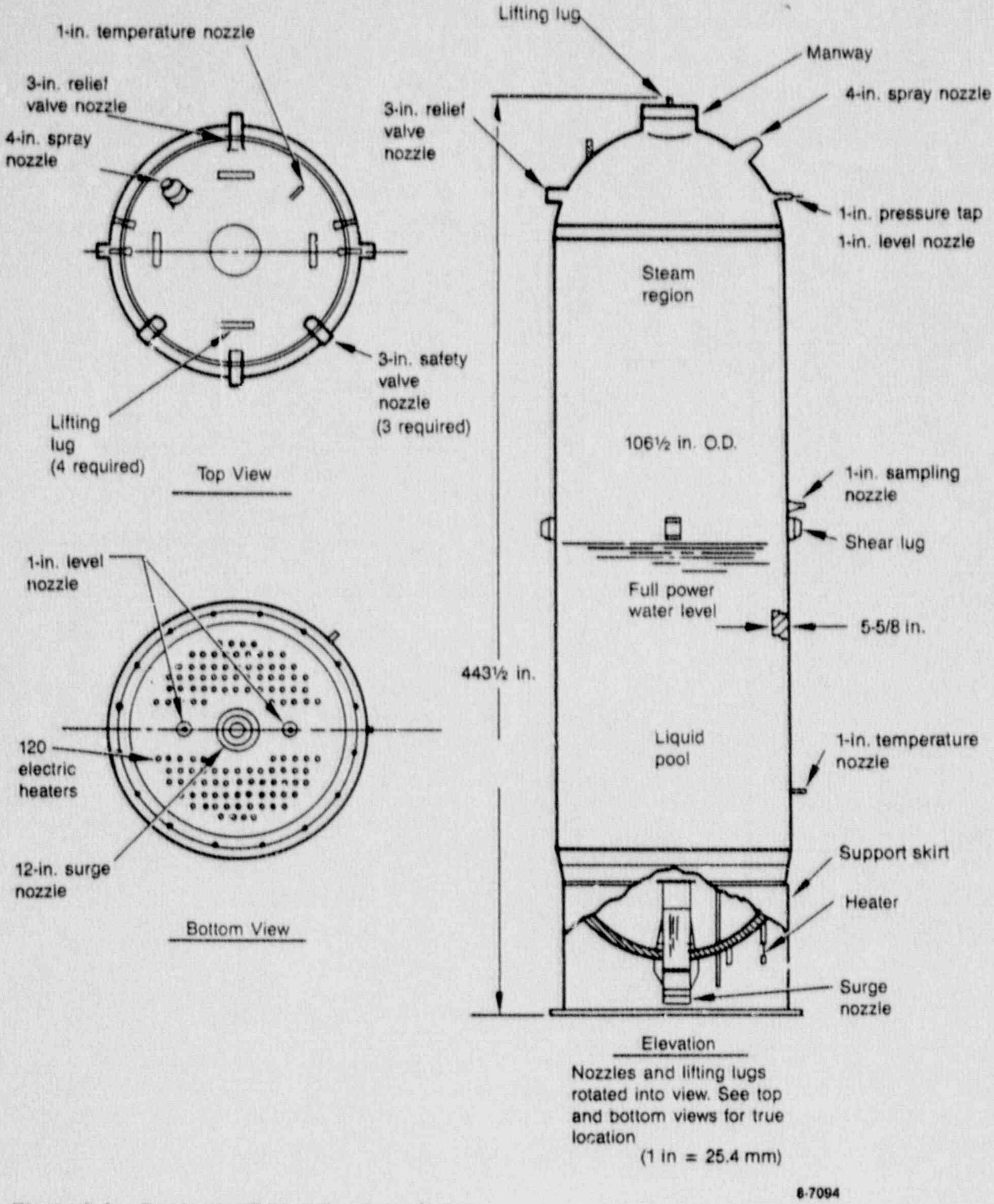


Figure 3.4. Combustion Engineering pressurizer.

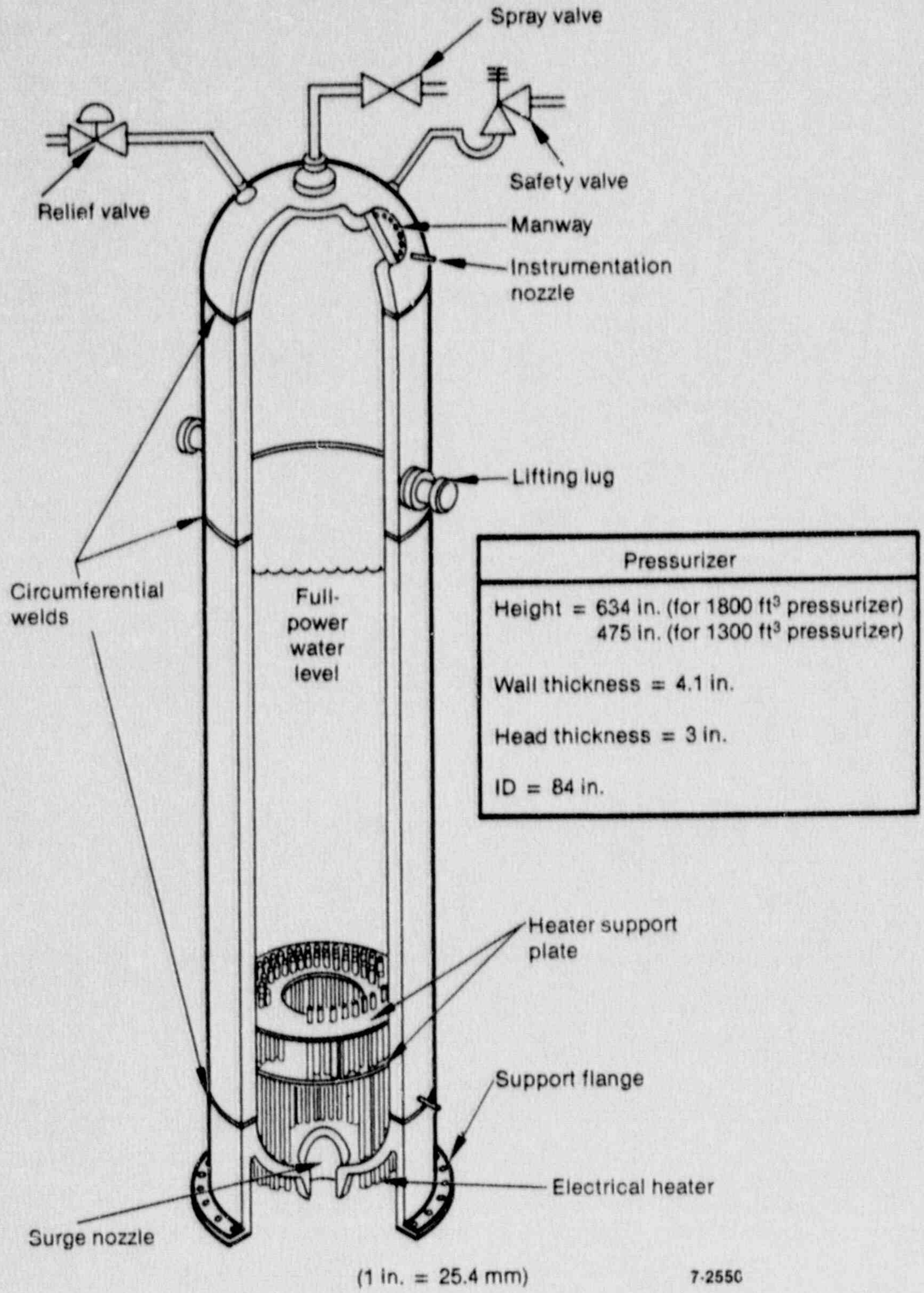


Figure 3.5. Westinghouse pressurizer.

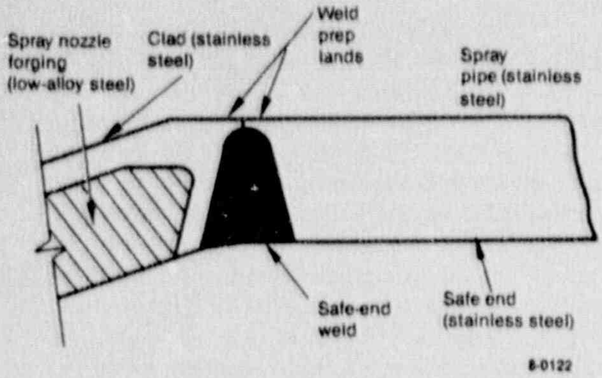


Figure 3.6. Cross section of pipe showing safe–end weld for Combustion Engineering spray nozzle. Assembly shown in Figure 3.10.

pressurizer walls and are encased by sleeves welded in the lower head. The heaters are typically about 25.4 mm (1 in.) in diameter and are covered by an Ni–Cr–Fe sheath, which surrounds the heater electrical elements and insulation (for example, magnesium oxide). A diagram of the Combustion Engineering arrangement is shown in Figure 3.8. In this design, the heater sheathes are directly in contact with the pressurizer fluid and form a portion of the primary pressure boundary. Seal welds between the sleeve and the stainless steel cladding on the inside of the pressurizer wall and between the sleeve and heater sheath complete the remaining portions of the heater pressure boundary. The Babcock & Wilcox arrangement is shown in Figure 3.9.

There are from 50 to 120 heaters in each pressurizer, with over 1000 kW (as high as 1800 kW in some plants) of total electrical heater capacity.[4,5,6,7,8,9] Redundancy has been included so that a given number of heaters, varying from plant to plant, can be inoperative at one time with plant operation continuing at an allowable reserve safety margin. A prescribed number of heaters are wired to the auxiliary power supply so that in the event of a loss of station power, pressure control of the RCS can still be maintained. In the Babcock & Wilcox design, the heaters are oriented horizontally (see Figure 3.3), while in the Combustion Engineering and Westinghouse designs (Figures 3.4 and 3.5) they are positioned vertically. Each heater can be separately removed for maintenance and replacement and is individually restrained to prevent high amplitude vibrations.

Coolant surges into and out of the pressurizer, called "insurges" and "outsurges," respectively, are caused by reactor power transients and occur through the surge–line nozzle located at the bottom of the

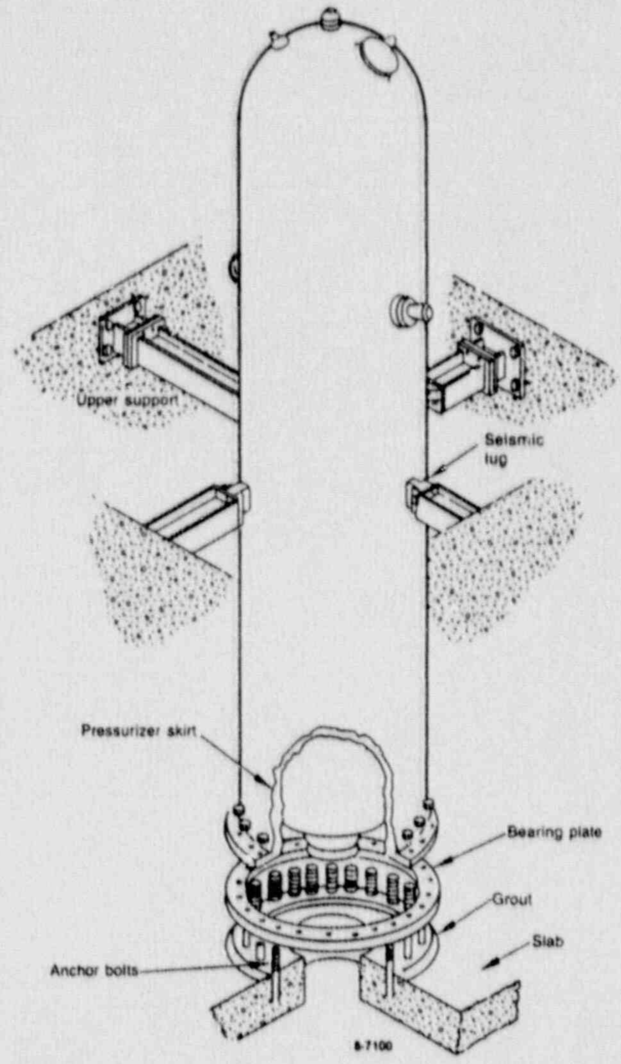


Figure 3.7. Westinghouse pressurizer support arrangement.

pressurizer. The flow path is from the hot leg of one of the RCS loops through the surge line [typically 254 to 355 mm (10 to 14 in.) in diameter] and then into the pressurizer (see Figures 3.1 and 3.2). When overall primary system cooling takes place, such as during reductions in load, the volume of water in the RCS decreases. The most severe case occurs during a scram from full power. This causes some water to leave the pressurizer (outsurge), reducing the density of the steam bubble and thus lowering the pressure. The pressure decrease is somewhat compensated for when water at the steam–water interface flashes to steam, thereby causing an increase in the pressure, although not enough to recover full operating pressure. When the pressure drops below a prescribed set point (specified in the Final Safety Analysis Reports), the heaters are automatically energized, adding heat to the remaining water at the bottom of the pressurizer.

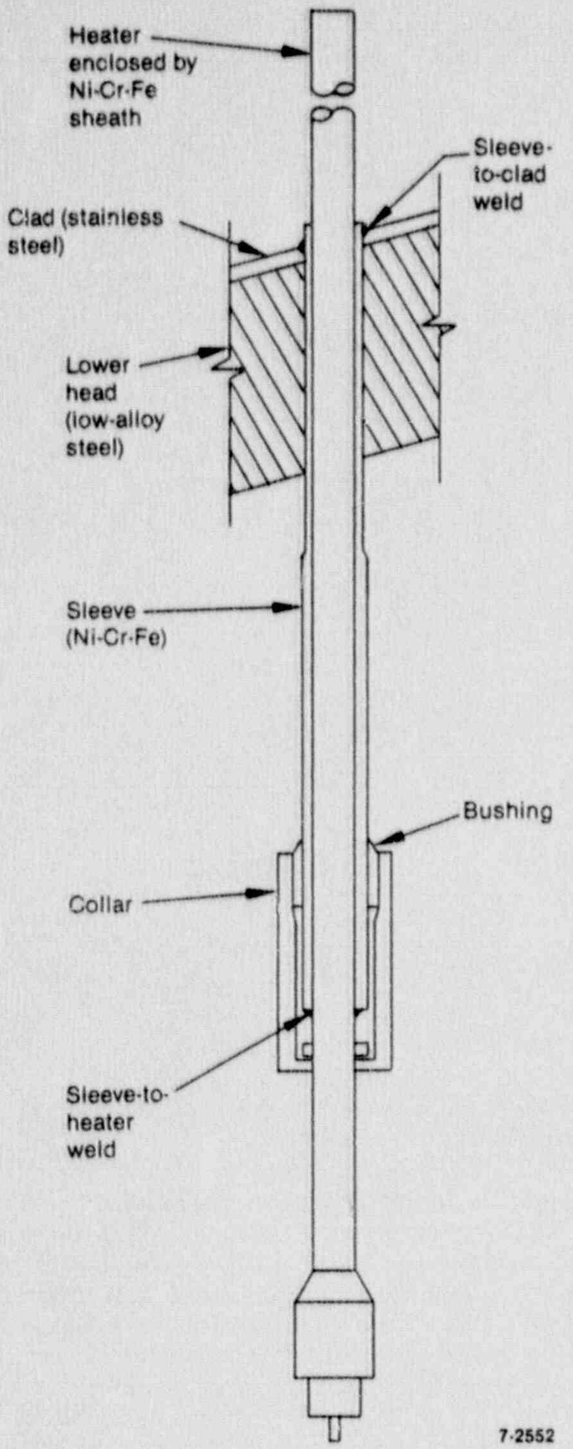


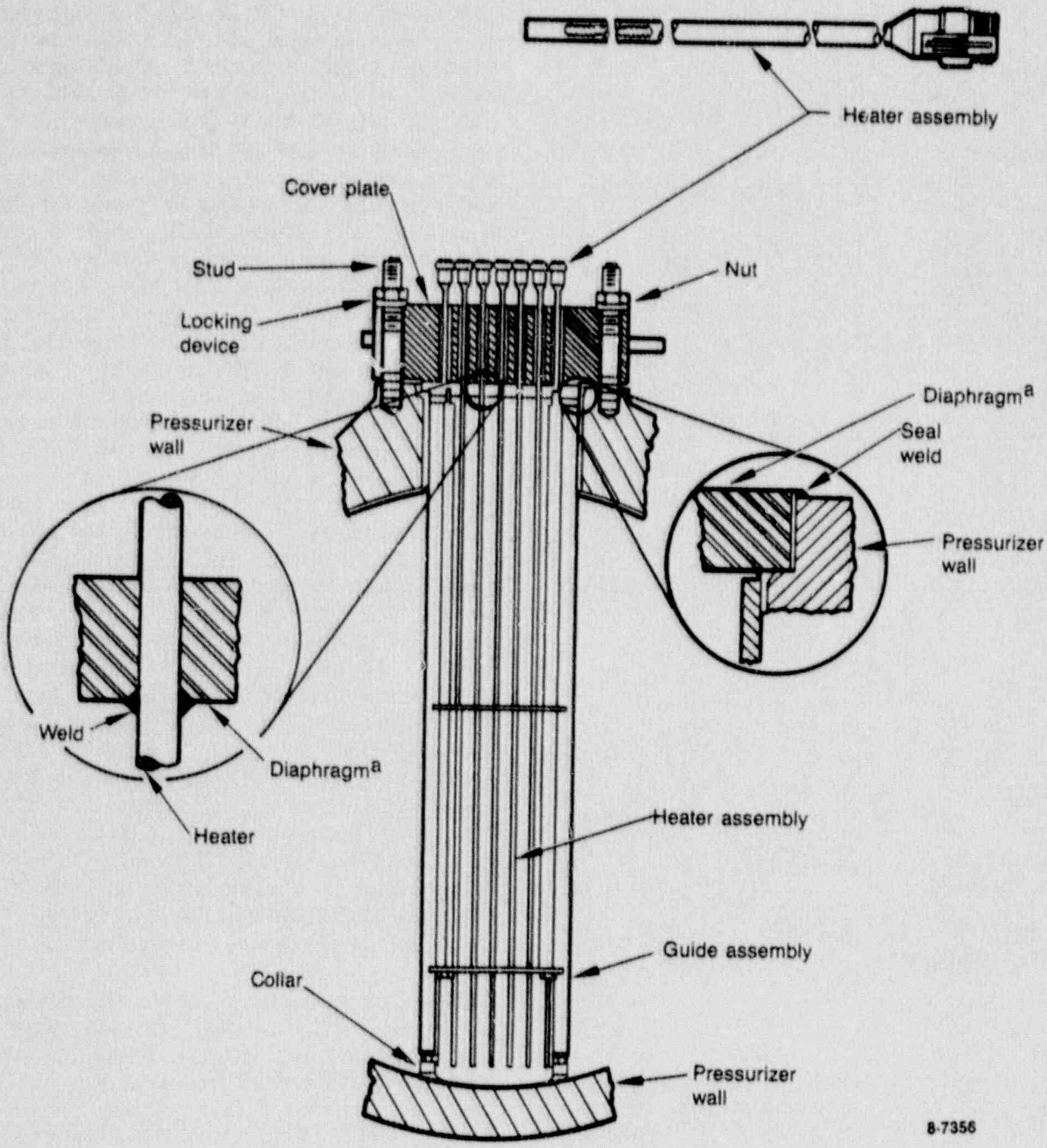
Figure 3.8. Combustion Engineering heater arrangement.

This water expands, contracts the steam bubble, and the pressure is returned to the operating range. When the pressure has been increased sufficiently, the heaters are automatically deenergized by a control system.

One of the design considerations for the pressurizer is that the heaters should not become uncovered during an outsurge of primary coolant. Uncovered heaters can burn out, and when the number of operable heaters drops below a prescribed minimum, the plant must be shut down for heater repair or replacement. Smaller pressurizers are somewhat more likely to be emptied than larger ones; for instance, a loss of power to the integrated control system inadvertently uncovered the heaters in the relatively small Rancho Seco pressurizer.[12] Although there was no reported damage to the heaters during this transient, in another event the Rancho Seco plant operators allowed the pressurizer heaters to become uncovered during a plant heatup, and thirty–three of the thirty–nine 2.74–m– (9–ft–) long tubes in the uppermost of the three heater bundles burned out.[13,14]

A screen at the surge line nozzle and baffles in the lower section of the Westinghouse pressurizer prevent cold insurge water from flowing directly to the steam–water interface (which might thermally shock the vessel wall) and assists both thermal and chemical mixing. A diffuser is located at the outlet of the surge–line nozzle in the Babcock & Wilcox design for the same purposes. The surge lines are designed to withstand the thermal stresses resulting from surges of relatively hotter and colder water that may occur during operation.[6,9]

There are thermal sleeves in both the surge and spray lines protecting the welds between the nozzles and the pressurizer upper and lower heads. Figure 3.10 shows the spray line thermal sleeve arrangement for the Combustion Engineering pressurizer. The thermal sleeve is expanded into a recess in the nozzle. The purpose of the thermal sleeves [2.5– to 5.1–mm (0.1– to 0.2–in.) wall thickness] is to reduce the thermal shock loadings to the nozzle inside wall and heel surfaces. This is possible because the temperature of the stagnant coolant between the thermal sleeve and the spray nozzle is almost constant along the length of the weld zone and is shielded from extreme changes in coolant temperatures by the thermal sleeve. The thermal sleeve–to–nozzle joints may be subjected to such thermal gradients, but these joints are not under internal pressure stress as is the pipe wall. Also, the sleeve is more flexible than the thicker pipe wall so the thermal bending stresses are not as great. However, the nozzle–to– piping weld could be subject to relatively high thermal stresses if the thermal sleeve happened to fail. Failed pressurizer thermal sleeves cannot enter the pressurizer because of the spray head and surge line diffuser. There is no reverse flow in the spray line that would allow a broken thermal sleeve to be carried into the RCS cold leg, but it is possible that a broken surge



a. Diaphragm is a thin plate underneath the cover plate.

Figure 3.9. Babcock & Wilcox heater configuration.

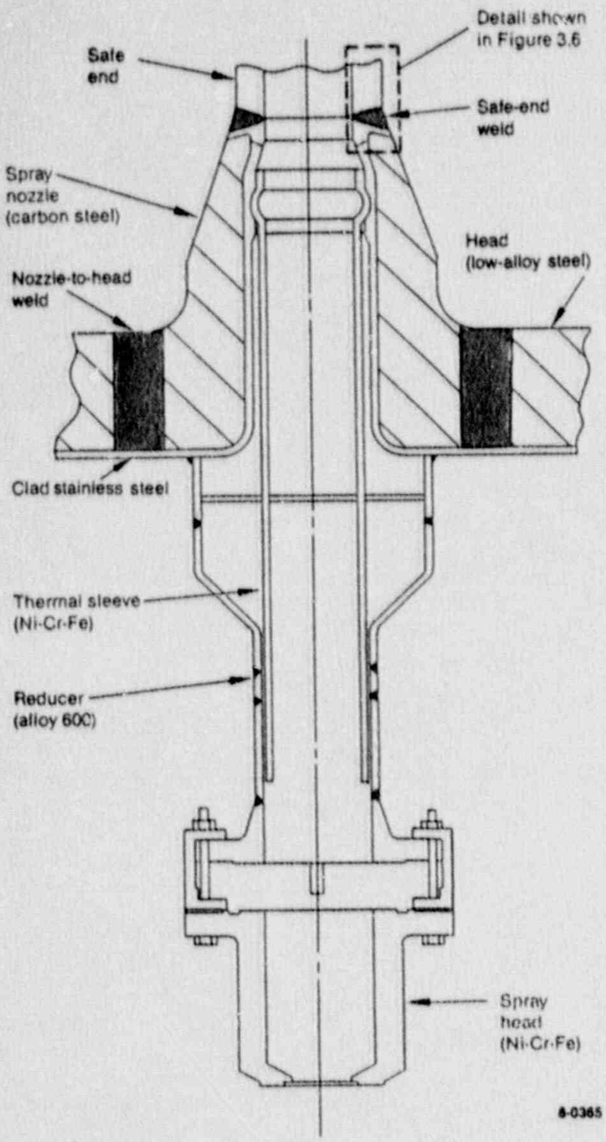


Figure 3.10. Combustion Engineering spray nozzle configuration.

line thermal sleeve could be swept into the hot leg during an outsurge, depending on the design. The spray and surge line thermal sleeves at the Westinghouse Trojan plant are welded on the upstream end over a 45-degree arc. Also, the sleeves themselves are of a larger diameter than the nozzle safe ends, thus preventing movement away from the pressurizer[15] This is also true for the Combustion Engineering design.

The temperature of the RCS water rises when reactor power increases, expanding its volume and causing an insurge into the pressurizer. The steam bubble is compressed, increasing its density and pressure, and a fog forms in the steam region as some of the steam condenses from the increased pressure.[a] The spray system, which is fed from one (for Babcock&Wilcox, see Figure 3.1) or two (for Combustion Engineering and Westinghouse three-loop and four-loop plants, see Figure 3.2) of the RCS cold legs, is automatically activated when pressure increases above a predetermined set point. The relatively cooler water [285°C (545°F) versus 343°C (650°F) saturation temperature] is sprayed into the saturated steam bubble, thereby condensing some of the steam in the upper portion of the pressurizer, which lowers RCS pressure. Maximum spray flow rates range from 0.023 to 0.057 m^3/s (370 to 900 gpm), depending on the particular plant.

A small continuous flow [6.3×10^{-5} to 1.3×10^{-4} m^3/s (1 to 2 gpm)][4,5,6,7,8,9] is provided through a manual bypass throttle valve around the power-operated spray valves to ensure that the pressurizer liquid is chemically homogeneous with the coolant and to prevent excessive heating of the spray nozzle and excessive cooling of the spray piping. Note from Figure 3.1 that the spray line is a small [typically 63.5 to 101.6 mm (2-1/2 to 4 in.) in diameter] piping system suspended in the reactor containment. Were there no flow in the line, heat losses to the reactor containment [which may be at an ambient temperature of <65°C (150°F)] would cause considerable cooling in the line. If water from the cold leg at a temperature of 285°C (545°F) were to be suddenly introduced into a much cooler spray line, high thermal stresses would be imposed on the pipe wall. The small continuous flow is designed to prevent this type of thermal shock. The thermal sleeve on the pressurizer spray connection is designed to withstand thermal stresses resulting from the introduction of the relatively cold 285°C (545°F) spray water into the pressurizer, whose temperature is that of the saturated steam, about 345°C (650°F).

A schematic of the upper section of a Westinghouse pressurizer, including the spray head (made of cast stainless steel), is shown in Figure 3.11. Stainless steel was chosen for its excellent resistance to erosion/corrosion. The spray heads in Babcock & Wilcox pressurizers (Figure 3.12) were either bought as sparger nozzles or fabricated in-house of wrought stainless steel material.[b] Some authors use the term spray

a. P. Griffith, private communication, MIT, Cambridge, Massachusetts, December 17, 1986.

b. Royal Douglas, private communication, Babcock & Wilcox, Barberton, Ohio, December 16, 1986.

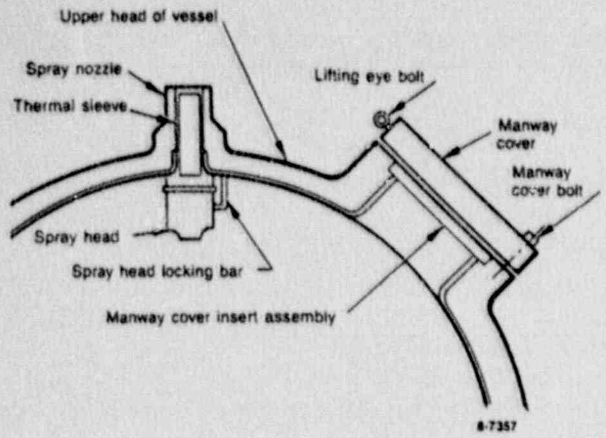


Figure 3.11. Westinghouse pressurizer spray head arrangement.

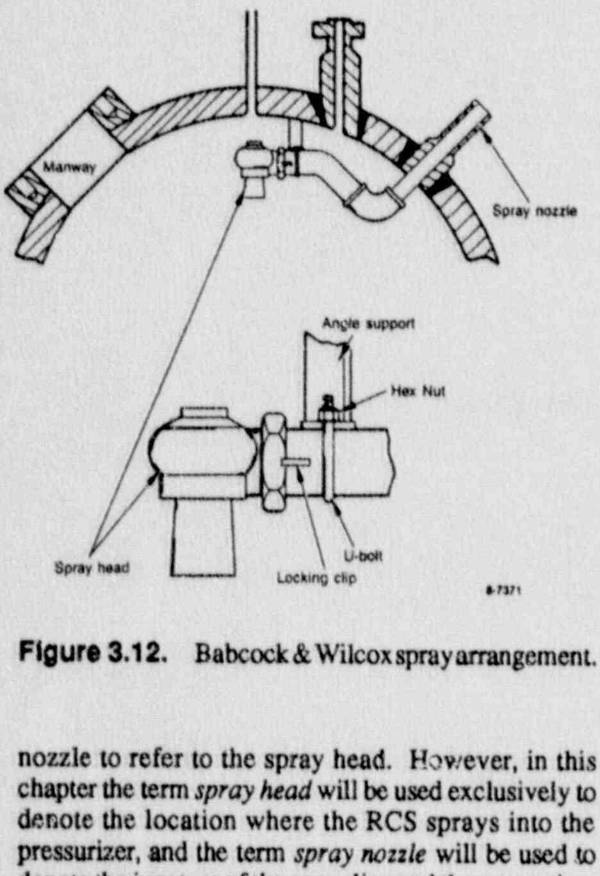


Figure 3.12. Babcock & Wilcox spray arrangement.

nozzle to refer to the spray head. However, in this chapter the term *spray head* will be used exclusively to denote the location where the RCS sprays into the pressurizer, and the term *spray nozzle* will be used to denote the juncture of the spray line and the pressurizer head, as shown in Figure 3.11. The nozzle at the other end of the spray line where it connects with the RCS cold leg is also called a spray nozzle.

Each pressurizer contains a standard pressure vessel manway penetration at the top for inspection and maintenance. A cover is typically 690 mm (27 in.) in diameter and 14.6 mm (0.575 in.) thick, covering a 410-mm (16-in.) opening. The cover is held to the vessel by 16 (20 in the Combustion Engineering design) 33- to 48-mm (1.3- to 1.875-in.) AISI 4340 studs. This is important from a license renewal perspective because it allows repair or replacement of pressurizer internal subcomponents. There are also numerous minor penetrations for sensing lines, pressure relief lines, sampling lines, vent and drain lines, etc.

Typical materials of construction (for locations relevant in understanding the overall license renewal issues associated with degradation under prolonged exposure to time, temperature, and chemicals) are listed in Table 3.1, from representative older vintage plants of each of the three PWR vendors.

3.2 Stressors

The transients that occur during plant heatups, cooldowns, hydrotests, leak tests, power adjustments, and abnormal and infrequent events (for example, reactor scrams and turbine trips) cause degradation of the pressurizer subcomponents. Typical numbers for these transients (as well as postulated seismic events) used in the design and analysis of a Westinghouse plant are listed in Table 3.2. (The number of Westinghouse design-basis transients is somewhat different from those listed in Table 4.1 for Combustion Engineering plants.) These types of stressors, which can cause fatigue damage to the materials of construction, have been discussed in Sections 3.2 and 5.2 of Reference 2.

One of the most severe transient cycles is the plant heatup-cooldown event. The vessel environment changes during the course of several hours from a cool [20°C (70°F)], unpressurized state to a hot [345°C (650°F)] condition at a pressure of 15.5 MPa (2250 psig), resulting in circumferential and axial bending stresses in the vessel wall. In a plant hydrotest, the temperature is raised only to about 205°C (400°F), but the pressure is raised to 21.55 MPa (3125 psi), which is 25% higher than the design pressure. Plant leak tests are performed at full operating pressure and at the corresponding minimum allowable temperature specified in the plant technical specifications. Insurges and outsurges can cause 33°C (60°F) changes in the coolant temperature during load increases and decreases up to 10%; and in a few seconds can cause as high as 60°C (110°F) changes during plant loading, unloading, and trip (see footnotes a and b for Table 4.1). These changes in coolant temperature cause significant fatigue damage, especially at the surge-line nozzle.

Table 3.1. Materials of construction at important pressurizer locations in representative older plants

Rancho Seco[4] (Babcock & Wilcox)	
Subcomponent	Material
Shell and heads	SA-516, Grade 70
Cladding	Types 308 and 308L or 309 stainless steel
Forgings	SA-508-64, Class 1
Spray and surge nozzles	Carbon steel, stainless steel cladding
Spray and surge lines	Type 316 stainless steel (both lines)
Heater sleeves	Type 304 stainless steel (drawn tubing) or carbon steel tubing with stainless steel clad
Spray head	Type 304 stainless steel (forged)
Manway studs	SA-320, Grade L43
Maine Yankee[6] (Combustion Engineering)	
Subcomponent	Material
Shell	SA-533, Grade B (Class 1)
Cladding	Types 308 and 309 stainless steel and Alloy 600[a]
Spray and surge nozzle safe ends	Alloy 600
Spray and surge nozzles	Carbon steel, stainless steel clad
Spray and surge lines	Type 316 stainless steel (both lines)
Heater sheathes	Alloy 600
Spray head	Alloy 600
Manway studs	SA-540 Grade B24
Diablo Canyon Unit 1[8] (Westinghouse)	
Subcomponent	Material
Shell	SA-533, Grade A (Class 1)
Heads	SA-216, Grade WCC
Cladding	Type 308 and 309 stainless steel
Spray and surge nozzle forgings	SA-508
Spray and surge nozzle weld ends	SA-182, Type F316
Spray and surge lines	Types 316 (pipe) and CF-8M (fittings) stainless steel (both lines)
Heater sleeves	SA-213, Type 316 stainless steel
Spray head	Cast stainless steel
Manway studs	SA-193, Grade B7

a. Alloy 600 cladding surrounds penetrations.

Table 3.2. Type and number of transients used in the design of Westinghouse plants

Transient	Design Events for 40-Year Lifetime
Low-Cycle Events[2]	
Plant heatup at 100°F/h	500
Plant cooldown at 100°F/h	500
Plant unloading at 5% full power/minute	15000
Plant loading at 5% full power/minute	15000
Step load increase of 10% full power	2000
Step load decrease of 10% full power	2000
Reactor trip from full power	400
Hydrotest to 3125 psi, 400°F	10
Operating basis earthquake (OBE)	200
Leak Test	60
High Cycle Events[2]	
Normal plant variation (100 psi and 10°F)	$>10^6$
Other Normal Events[a]	
Spray actuation	Information unavailable
Heater actuation	Information unavailable
Sloshing of liquid volume	Information unavailable

a. Includes actuations initiated by low-cycle transients.

Also included in Table 3.2 (in the category of "Other Normal Events") are spray and heater actuation and sloshing temperature transients. It is assumed in the design analyses that there is one spray actuation and one surge associated with each related transient.[8] Actually, the exact numbers of these events are not precisely known, nor has the existence and magnitude of liquid sloshing on the vessel walls been confirmed. Griffith has reported that there was no sloshing in his experiments with a small simulated pressurizer (the effects of the transients were viewed through Plexiglass windows in his experimental model).[a] He also stated that the pressurizer is rarely in a state of thermal-hydraulic equilibrium and that conditions are constantly changing within the boundaries. (His experiments are discussed in more detail below.)

The normal actuation of coolant spray to reduce pressure introduces subcooled water from the RCS cold legs [285°C (545°F)] through the outlet of a spray system that is surrounded by 343°C (650°F) saturated steam. This causes thermal stresses and fatigue damage to the spray heads, nozzles, and nozzle thermal sleeves. The cast stainless steel spray heads are also subject to thermal aging (embrittlement) and the spray heads can be eroded[16] because of the high [0.024- to 0.057-m^3/s (375- to 900-gpm) maximum] [4,5,6,7,8,9] spray flow. Conceptually, the heat-affected zones (HAZs) of the safe end welds in the spray nozzles andadjacent areas of the stainless steel cladding may be susceptible to damage by intergranular stress corrosion cracking (IGSCC), but there is no evidence to date that this type of attack can occur in a PWR.[17]

The thermal-hydraulic phenomena in the pressurizer can sometimes become complicated because both the liquid and vapor phases are subject to perturbations caused by the subcooled spray, heater activations, and relief/safety valve actuations. Although the liquid and vapor exchange mass and energy, they need not be in thermodynamic equilibrium; furthermore, significant stratification within the liquid pool at the bottom of the pressurizer may take place. A sophisticated analytical model that included the effects of the condensation coefficient, subcooled spray, heaters, and boundary conditions of various typical transients was developed

a. P. Griffith, private communication, MIT, Cambridge, Massachusetts, December 17, 1986.

in an EPRI project.[18] Predicted results (pressures, temperatures, water level, etc.) were compared with actual pressurizer behavior during an insurge, an outsurge, spray actuation, and heater actuation. The model predictions were generally in good agreement with the measured data; however, they were sensitive to the assumed value of the condensation rate coefficient, which determines how quickly the steam phase is converted to liquid and consequently the time for the pressure to be lowered during an insurge.

Analyses and experiments designed to more fully understand the thermodynamics and heat transfer within PWR pressurizers during transients are described in References 19, 20, and 21. Griffith's experiments with a small-scale, low-pressure pressurizer[19] during an insurge showed that (a) significant condensation occurred on the walls [inner diameter (ID) of the shell], which is cooler than the steam bubble, (b) axial conduction in the walls was negligible, (c) there was very little radial temperature variation in the liquid, and (d) the stratified liquid layers were very stable. In similar scaled experiments,[20] the interface heat transfer coefficients between the liquid and steam regions were studied. These coefficients were significantly affected by the presence of noncondensable gases at the interface. Since the spargers at the bottom of pressurizers are generally unique from plant to plant, Griffith believes there is considerable uncertainty in characterizing the heat exchange during transients,[a] especially for the smaller pressurizers with shallower pools. The results of his experiments, giving time-temperature variations for the vessel wall and pool in 25 separate transients, could provide benchmarks for comparisons of analytical and experimental studies to validate pressurizer thermal-hydraulic prediction models. Studies using a pressurizer system computer code called PRSZR[21] show that a detailed surge-line model and multivolume representation of the pressurizer interior (particularly the liquid region) agree better with plant transient data than do coarser models.

Fluctuations in water level during transients could cause a considerable number of thermal stress cycles in the pressurizer shell. A circumferential weld located in this region on a pressurizer (for example, the central weld in Figure 3.5), would be subjected to thermal fatigue over its entire 360-degree length. This case would be worse than for a longitudinal (vertical) weld, for which only a few degrees around the shell would be weld metal, and the remainder of the circumference would be plate material, though the pressure stresses on the longitudinal weld are twice as high as those on the circumferential weld.

Other stressors are differential thermal movement (causing rubbing of the immersion heater sheathes), internal pressure within the vessel, steam leakage through bolted joints, and prolonged exposure to chemical and thermal conditions, which can potentially lead to degradation. The latter includes thermal embrittlement of the cast stainless steel spray heads, plating out of chemicals on the immersion heaters creating local hot spots, and chemically assisted IGSCC of the heater sleeve welds and the stainless steel in the HAZs of the nozzle safe end field welds under tensile stress (although to date there has been no evidence of IGSCC in pressurizer safe-end welds). Shop welds such as those between pressurizer shell sections are postweld heat treated to reduce residual stresses. Steam leakage that interacts with lubricants used to assemble manway bolted joints can degrade the bolts.[17,22]

High residual stresses in the heater sheath walls can promote stress corrosion cracking. Corrosion, moisture ingress, insulation breakdown, and localized hot spots may lead to eventual heater burnout and sleeve failure. Since the heater elements have limited performance lifetimes and individual heaters are easy to replace, they are relatively unimportant from a license renewal point of view; however, loss of the pressure boundary at heater sheath locations is a technical safety issue associated with the residual life assessment of pressurizers. Water leaking through a degraded heater sleeve or sheath may not only short-out the heater element, but if a second failure location develops, the leakage can continue past the heater cavity to the reactor containment space, resulting in a primary-to-containment leak. Also, the boric acid in the leaking coolant may cause corrosion damage to the carbon steel base metal. Some heaters have an internal high-pressure seal to prevent leakage to the containment.

Design seismic events are also stressors, particularly to the pressurizer supports. However, for most plants it is not likely that these will contribute very much to fatigue usage or aging because the probability of significant earthquake stresses over the plant lifetime is low.

3.3 Degradation Sites

The spray and surge nozzles are subject to high fatigue usage induced by changes in reactor power and plant heatup and cooldown cycles. IGSCC in the

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a. P. Griffith, private communication, MIT, Cambridge, Massachusetts, December 17, 1986.

HAZs of the nozzle safe end welds is also possible, although, as stated above, there has been no evidence of IGSCC in the heat-affected zones of the pressurizer welds.[16] Fatigue problems with nozzle-thermal sleeve assemblies have been identified in Babcock & Wilcox and Westinghouse designed reactors.[15,23] Although these were associated with the safety injection systems, damage may also be occurring in the pressurizer system but at a slower rate. Spray heads may be degraded by erosion and thermal aging.

The cylindrical portion of the pressurizer vessel can undergo fatigue usage[16] caused by (a) heatups and cooldowns, (b) variations in water level caused by insurges and outsurges, and (c) the effects of the subcooled spray water contacting the upper shell. The shell is very important from a license renewal standpoint, since a crack in the vessel wall must be repaired and might even require replacement of the entire vessel. The heads experience less fatigue usage. Immersion heater sheaths in Combustion Engineering plants (and possibly other plants) may be susceptible to stress corrosion cracking when high residual stresses are present. For example, stress corrosion cracking of a heater sheath at the Arkansas Nuclear One Unit 2 plant resulted in a pressurizer leak in April 1987. Stress corrosion cracks in the heater sheath exposed the electric insulation within the sheath to the pressurizer coolant, which caused expansion of the insulation, axial cracks in the penetration sleeve and sleeve weld, and finally leakage of pressurizer coolant into the containment. (This event is discussed in somewhat more detail in Section 3.4.2.) The only other instance of a pressurizer leak in the United States was at the Calvert Cliffs Unit 2 plant in May 1989, where twenty-two of 120 heater penetrations were found to be leaking.[24,25] In addition, a pressure/level instrument penetration on the pressurizer upper head was also found to be leaking. The root cause for the Calvert Cliffs pressurizer leaks is not yet known.

Immersion heater sheaths can also potentially experience mechanical wear and thinning caused by rubbing action of their supports at their interfaces, which are induced by thermal growth.[16] Electrical failures have occurred in the heaters themselves.

When steam leaks through a gasket in a PWR, it can react with lubricants that were used to assemble the bolted joint. This has led to corrosion and subsequent failures of some manway closure bolts[17,22] and could potentially cause boric acid corrosion damage to the low-alloy steel head. Coolant leaks through failed pressurizer heater sleeve welds have also resulted in boric acid corrosion of the low-alloy steel head.

3.4 Degradation Mechanisms

3.4.1 Metal Fatigue. The metal fatigue discussion in this section is divided into two parts: high- and low-cycle fatigue. Low-cycle, high-stress fatigue is the most worrisome to designers and accounts for practically all of the fatigue usage in design calculations. Figure 3.13 shows the ASME Code Section III fatigue curve for carbon and low-alloy steels, plotted as the alternating stress intensity (S_a) at a location versus the number of cycles to failure (N) at this stress. The curves were based on uniaxial strain cycling data obtained from specimens tested in air in which the imposed strain amplitude (half-range) was multiplied by the elastic modulus to convert the strain values into stress units. A least-squares best-fit approximation to the experimental data was applied to the logarithms of the stress values. Then the curves were adjusted where necessary to account for the maximum effect of applied mean stress. This adjustment can be seen for the high-strength curve (solid line) above 10^4 cycles. Finally, the design stress intensity curves were determined by applying a reduction factor of 2 on stress or 20 on cycles, whichever was more conservative at the point on the curve.

The fatigue usage for the various transient combinations is determined by first calculating the peak stress intensity range for each combination and determining the allowable number of cycles from a curve, such as Figure 3.13. The stress intensity value of one-half the range, representing the alternating stress intensity, adjusted for the effect of elastic modulus, is used in reading the curve. The allowable stress cycles are divided into the design cycles (such as shown in Table 3.2) to determine the fatigue usage for this group of cycles. The cumulative fatigue usage for all transients is the sum of the individual usages. By Miner's rule, if the cumulative fatigue usage is <1.00, then the acceptance criterion is met.

For many metals, including steels, the fatigue curve flattens at a given number of cycles (10^6 to 10^8 cycles is generally considered typical for steels). The stress at this point is called the fatigue limit. If the alternating stress for a particular event does not exceed the fatigue limit, the member will not fail in high-cycle fatigue; that is, the number of allowable cycles at this stress is infinite. This concept is based on materials tested in air, however, and the existence of a fatigue limit in the presence of corrosion-assisted fatigue has not been proven.[11] Thus, an approach where the S-N curve has a shallow slope (for example, -0.05) beyond 10^5 cycles is being considered and is more reasonable

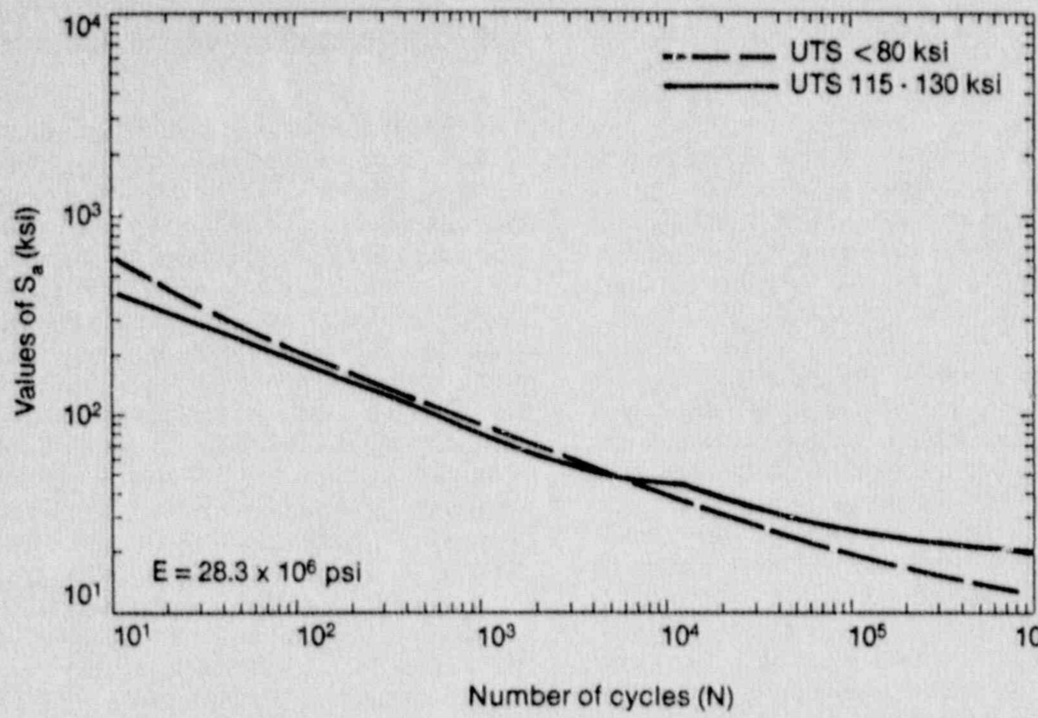

Figure 3.13. Design fatigue curve for carbon and low-alloy steels.[1]

to use for long-life fatigue assessment than assuming a fatigue limit where no fatigue usage is accumulated below some stress amplitude.

Low-Cycle Fatigue. The degradation mechanism that is pervasive throughout the pressurizer subcomponents is low-cycle thermal fatigue. Although all of the designs have included thermal sleeves and a spray bypass flow to minimize thermal gradients in the metal during operational transients, several locations will still experience relatively high fatigue usage, as discussed above. This may be both an actual problem and an analysis problem. Conservative thermal models of the two-phase thermal mixing within the vessel, and worst-case thermal gradient assumptions within vessel and nozzle walls were generally used in the original design and analysis of the pressurizers. An example of one such assumption is that the interior wall "skin" temperature is at the colder incoming fluid temperature [for example, 285°C (545°F)] while the remainder of the wall is at the saturated steam temperature of the vapor bubble [343°C (650°F)]. A preliminary analysis using these assumptions was often completed for the anticipated cycles expected for a 40-year plant lifetime. If the fatigue usage was <1.00, (even though it may be as high as 0.99), no further analysis was performed. However, should the fatigue usage prove to be >1.00, then further refinements were made on the thermal/stress models to reduce the conservatism in the calculations at locations of high fatigue.

The fatigue usage factors calculated for a 40-year life for the Westinghouse Surry 1 pressurizer are listed in Table 3.3.[16] While these fatigue usage factors are not exactly representative of all other designs, the spray and surge line nozzles on Babcock & Wilcox plant[a] and Combustion Engineering plant[b] pressurizers also have high calculated cumulative fatigue usages. Therefore, the vessel lifetime cannot be extended very much past 40 years without exceeding the ASME Code fatigue limits unless significant reductions in fatigue usage can be calculated. Refined analyses may or may not be sufficient to reduce the fatigue usage to a satisfactory level for license renewal. The Pressure Vessel Research Committee has a program under way to evaluate fatigue criteria for life assessment of shell structures.[26]

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a. G. J. Vames, private communication, B&W, Lynchburg, Virginia, October 17, 1986.

b. E. A. Siegel, private communication, Combustion Engineering, Windsor, Connecticut, December 12, 1986.

Table 3.3. Pressurizer fatigue usage factors for 40-year design life[16]

Location	Cumulative Usage Factor
Surge nozzle	0.949
Seismic lug	0.947
Upper shell	0.92
Spray nozzle	0.821
Lower head	0.20
Heater well	0.13

Although the upper shell has the third highest usage factor listed in Table 3.3, it is very important in that fatigue cracking in this area would require repair or replacement of the entire pressurizer, whereas the surge line nozzle and seismic lug would be much easier to repair or replace. The Combustion Engineering pressurizer supports (the attachment welds for the support skirts) are also subject to high usage factors caused by thermal gradients between the vessel and the supports. A large part of the usage for the seismic lug in the Westinghouse design is attributable to a very conservative estimation of its thermal interaction with the shell.

There is considerable uncertainty in the current transient analyses of PWR pressurizers, and more realistic thermal-hydraulic mixing models need to be developed. Along with improved thermal-hydraulic models, more accurate calculations of the through-wall temperature gradients might be used as part of the justification to extend vessel life. Using more refined models, it might be possible to demonstrate that the extent of thermal mixing of the fluid and the heat transfer within the metal is greater than previously assumed, and revised wall temperatures may result in lower thermal stresses and low-cycle fatigue usage. On the other hand, it is possible that the new models could predict somewhat more severe thermal gradients than the present models predict.

The actual number of transients such as spray and heater actuations, important to determining the true fatigue usage at key locations, is unknown. Estimates were used for plant design purposes. Cataloging actual cycles and time-temperature histories of each event during operations to date will also be useful in establishing a more realistic fatigue usage. Nuclear steam supply vendors are already encouraging utilities to establish monitoring systems to catalog the number of actual transients to which components are subjected. For example, Combustion Engineering has provided to its utility clients a system to monitor transients, particularly for spray actuation, since the spray line has one of the highest calculated cumulative fatigue usage factors in the RCS.[b] Duke Power Company has adopted the Allowable Transient Cycles Program offered by Babcock & Wilcox, which includes a transient logging program for critical components such as the surge- and spray-line nozzles.[27]

The design analyses used to justify the 40-year original plant lifetime were based on the ASME Code fatigue curves for materials tested in air. However, corrosion-assisted fatigue may occur at various degraded sites (that is, if the base metal is exposed to primary coolant) subjected to stresses less than predicted by the ASME Code fatigue curves. Weld locations where crevices or stress concentrations may occur are particularly susceptible; thus, this issue also needs to be addressed, and guidance (see Section 3.4.3 of Reference 2) on long-term fatigue would be appropriate for inclusion into Section XI of the ASME Code.[28] The International Cyclic Crack Growth Rate (ICCGR) Group has been established to exchange information and coordinate research findings on this problem. Forty-six papers were presented at the Second International Atomic Energy Agency Specialists' Meeting onSubcritical Crack Growth,[29] and relevant experimental data on environmentally assisted fatigue are included in the EPRI Database on Environmentally Assisted Cracking at Battelle Memorial Institute.[30] An approach that is certainly applicable in determining the component lifetime is to assess not only crack initiation but also crack growth.[31]

High-Cycle Thermal Fatigue. The lifetime effects of the high-cycle thermal fatigue that may be caused by the subcooled spray impact on the pressurizer walls; the sloshing of the liquid at the steam-water interface; and liquid level changes resulting from insurges, outsurges, and heater actuations need to be evaluated. These high-cycle fatigue events could cause initiation of cracks that could later be propagated by the high-stress, low-cycle fatigue events. Corrosion fatigue could also result in crack growth where the cladding has been breached since it is not known whether a fatigue limit exists in the presence of this degradation mechanism. One possible location susceptible to high-cycle fatigue is in the wall of the vessel shell near the usual steam-water interface. Although to date there has been no evidence of high-cycle fatigue degradation at this or any other location, this issue should be evaluated during any residual life assessment.

3.4.2 Intergranular Stress Corrosion Cracking. Pressurizers are fabricated as a unit in the shop and shipped to the plant where the piping is field-welded to the pressurizer unit. Surge- and spray-nozzle stainless steel safe ends sensitized during the original field-welding may be susceptible to IGSCC.[16] IGSCC has been a significant problem in the heat-affected zones of the BWR austenitic stainless steels (304, 304L, and 316 base metal) piping and safe ends. However, IGSCC generally requires the presence of three factors: a high level of tensile stress (applied or residual), material that is sensitive to attack, and the presence of a corrosive anion. Examples of such anions are oxygen, chlorides, fluorides, sulfates, and other sulfur ions. The first two factors appear as an inherent result of the normal welding process used for assembling piping systems in currently operating reactors. The PWR RCSs have a hydrogen overpressure maintained as an oxygen scavenger during power operation. As a result, the primary pressure boundary piping of PWRs have generally not been found to be affected by IGSCC.[32] In a 1971 topical report,[33] Westinghouse presented a rationale why IGSCC should not be a problem in PWR primary systems. A few areas of concern were identified where a lack of venting could cause exposure of sensitized stainless steels. These "dead leg" locations include the surge line (between the thermal sleeve and nozzle) and safety valves. However, Westinghouse does not believe that any problems will occur in these areas.[33]

A leak in the Arkansas Nuclear One Unit 2 (Combustion Engineering) pressurizer heaters was attributed to stress corrosion cracking.[34] The heaters were constructed using Alloy 600 Ni–Cr–Fe sheaths surrounding internal heater conductor wires and resistance heating coils. Compacted magnesium oxide (MgO) was used as an insulator between the Alloy 600 sheaths and the heating elements. Apparently, a swaging process was used to reduce the diameter of the heaters during fabrication, simultaneously compressing the MgO to an acceptable density and creating high residual stresses in the Alloy 600 sheath. The material was not annealed after the swaging process. The high residual stresses made the sheathes susceptible to stress corrosion cracking, which penetrated the sheath wall, allowing water to enter the internal portion of the heater and contact the MgO insulation. MgO exhibits a high affinity for water and can expand to 2 or 3 times its original volume when hydrated. This expansion produced swelling and eventual rupture of the heater sheathes. The rupture produced significant damage to the heater sleeves and sleeve-to-clad welds (see Figure 3.8), leading to a second failure location that allowed water to pass between the sleeve and vessel wall and eventually to the containment. This problem appears to have been associated with a particular vendor and manufacturing technique, and the replacement heaters made by the General Electric Company do not appear to have this problem. However, twenty-two of the 120 penetrations where the heater sleeves enter the bottom of the Calvert Cliffs Unit 2 pressurizer were recently found to be leaking.[24] Stress corrosion cracking is suspected. Combustion Engineering units have also experienced IGSCC problems at partial penetration welded instrument nozzles. These problems have been limited to one particular heat of Alloy 600 material having a high, but within specification, hardness; and the affected welds have been repaired.[35]

Although other problems with IGSCC in pressurizers have not been encountered to date, which has been attributed to careful attention to primary coolant water chemistry in PWRs,[16] the USNRC warns against the unwarranted conclusion that IGSCC will never occur.[32] Therefore, continued surveillance should be exercised by nondestructive testing throughout the plant lifetime to guard against this potential failure mechanism. Sensitized stainless steel has been reported in nozzle safe ends[16] and pressurizer safety valve nozzles.[36] Further discussions on IGSCC may be found in Sections 5.3.3 and 10.4 of Reference 2.

3.4.3 Stress Corrosion Cracking of Bolts. The USNRC has reported 44 distinct instances of bolting degradation at nuclear plants between October 1964 and March 1982.[17] The largest single cause was stress corrosion cracking, of which at least two were attributed to lubricant-moisture interaction, which resulted in a corrosive environment. When steam leaks through a gasket in a PWR, it can react with lubricants used to assemble the bolted joint. Five corroded pressurizer manway bolts were replaced at a St. Lucie plant in 1977, and two bolts of the Calvert Cliffs 2 (Combustion Engineering) pressurizer manway were replaced in 1981.[22] Experiments by the Brookhaven National Laboratory have shown that the tensile strengths of low-alloy steel specimens with notches that simulate threads can be reduced by a factor of three in a steam environment when molybdenum disulfide lubricants are present.[17] This problem can be minimized by controlling leakage, good housekeeping practices, and reducing the preload stress in the bolts. Specific recommendations to prevent bolted-joint leaks are given in Reference 37. EPRI is also developing recommendations to prevent leakage and advanced ultrasonic techniques to detect bolt wastage and cracks.

This type of attack has also affected other primary system components. For example, 5 of 20 studs failed during the March 1982 removal of the primary manway cover from steam generator number 2 at the Maine Yankee (Combustion Engineering) Atomic Power Plant. Steam generator primary manway bolt cracking incidents attributable to molybdenum disulfide and the products of hydrolysis have also occurred at Arkansas Nuclear One Unit 1 and Oconee 3 (both Babcock & Wilcox plants).

3.4.4 Mechanical Wear. Mechanical wear of the immersion heater sheaths is a degradation mechanism that will also need to be evaluated using nondestructive techniques. Of course, burnout of heater elements requires periodic replacements as the heaters are not expected to serve for 40 years, but if a heater sheath (which forms the pressure boundary between the primary coolant within the pressurizer and the heater elements, and thereby also is part of the pressure boundary between the coolant and the exterior of the pressurizer) is breached, an unisolatable leak will occur.

3.4.5 Erosion. Another mechanism of concern is erosion of the spray head caused by the high flow rate within the spray cone, which is the part of the spray head that distributes the flow across the inside of the vessel. The stationary vanes, which determine the shape of the cone, can be rendered ineffectual with sufficient erosion-caused metal removal; then it is necessary to replace the spray head. There is a high probability that this operation will have to be performed for plant life extension; however, it is not a major operation and can be accomplished through the manway at the top of the pressurizer. If the problem is not detected and repaired fairly early, however, the spray could be directed at a single location on the shell wall, causing high thermal stresses and high fatigue usage, leading to a crack in the wall. No failures of spray heads in plant operation are known at this time.

3.4.6 Thermal Embrittlement. Like all cast stainless steel primary coolant components, spray heads that are fabricated from cast stainless steel are potentially susceptible to thermal embrittlement. However, since the spray head location is hotter than those of the other components, such as the cast stainless steel pipe elbows, and the rate of thermal embrittlement increases with temperature, spray head degradation may be of particular concern. On the other hand, it is easier to change out spray heads than certain other cast stainless steel components.

The CF-8 and CF-8M cast stainless steels and their welds have a ferrite phase that is susceptible to microstructural changes, which in turn can cause a decrease in the overall impact and fracture-toughness properties of the alloy. The overall embrittlement depends on the amount and distribution of the ferrite. Thermal embrittlement has previously not been fully investigated but is currently being examined by EPRI,[38,39] the USNRC,[40] and a Westinghouse owners' group.[16,31] Although experimental work has determined that the problem exists, there are no nondestructive examination techniques suitable for in-plant usage and that will fully reveal to what extent thermal embrittlement has damaged the metal structure.

3.4.7 Electrical Aging. Individual heater elements have rated lifetimes on the order of 10,000 h for 5000 temperature cycles.[41] Thus, it is not uncommon to have elements burn out during normal plant operation, creating an open circuit in a given heater set. The faulty element is either replaced or bypassed to make use of other functioning elements to complete the circuit. Bypassed elements can create overvoltage conditions in the other elements, which may shorten their lifetimes.[41]

Insulation breakdown and increased loop resistances can also be expected in aged plants. The use of unprotected joints in heater termination boxes presents vulnerable areas for oxidation, corrosion, and dust and moisture contamination.[41] Since the pressurizer heaters are the hottest location in the RCS, other than the reactor core, it is postulated that chemicals from the RCS that have an inverse solubility may plate out on the immersion heater sheathes, which decreases the thermal conductivity creating localized hot spots on the elements. This mechanism also may shorten heater life.

Heater burnout presents no serious license renewal problems, however, because the heaters are designed to be easily replaced. Replacement of immersion heaters can be routinely performed during regularly scheduled maintenance shutdowns.

3.5 Potential Failure Modes

Other than associated control valves (for example, relief, safety, and spray valves), the expected periodic loss of individual heater element functionality for the various reasons previously discussed and the heater sheath/sleeve leaks in the Arkansas Nuclear One Unit 2 and Calvert Cliffs Unit 2 plants, pressurizers have provided years of relatively trouble free operation.[42,43,44] Therefore, the potential failure modes must be based on the likely degradation mechanisms such as through-wall crack growth caused by metal fatigue, stress corrosion cracking or manway bolts, stress corrosion or mechanical wear of the immersion heater sheaths, and erosion or thermal embrittlement of the spray heads.

The failure mode for the vessel would probably be a leak caused by a ductile failure of the metal rather than a catastrophic break (such as would be caused by a brittle fracture). The pressurizer could also fail as a result of loss of the support structure from metal fatigue caused by thermal and seismic events. The calculated end–of–40–year–life fatigue usage for the Surry 1 seismic lug on the support structure is 0.947, as shown in Table 3.3, but a more realistic thermal analysis would probably lower this number considerably. Failure of the pressurizer vessel would have serious consequences in that a large–break loss–of–coolant accident (LOCA) could occur.

Failure of the spray head would be gradual and would degrade the ability of the pressurizer to control pressure surges since the spray head could not spray uniformly. This event would not be serious since the relief and safety valves provide overpressure protection, but it would make plant pressure control more difficult until the spray head was replaced and could result in higher thermal stresses in the upper shell wall than were predicted in the design analyses if the spray flow were streamed directly onto a single location on the shell interior. It would be relatively easy to replace the spray head.

Failure of thermal sleeves on the spray and/or surge nozzles would result in increased thermal stresses on the nozzles and accelerate their rate of fatigue usage. It is not likely that these thermal sleeves could become loose parts in the RCS or pressurizer.[15]

Leakage of primary coolant at the manway bolts or at the heater sleeve welds represents failure of the primary pressure boundary and has occasionally occurred. Failure of heater sleeve welds has the potential of becoming a serious problem because it is possible that these sleeves could blow out and result in an unisolatable small–break LOCA. However, the pressurizer is located above the reactor vessel, so a leak would not uncover the core immediately.

The leaking primary coolant could corrode the low–alloy steel base metal. The primary effect of boric acid leakage is wastage or general dissolution corrosion of the low–alloy steel.[45] In one incident, the failure of a weld between the heater sleeve and the stainless steel cladding on the pressurizer inside wall caused $\sim 1.26 \times 10^{-7}$ m^3/s (0.002 gpm) leakage of primary coolant through the 10–cm (4–in.) thick pressurizer lower head.[34] The leakage, $\sim 1.26 \times 10^{-7}$ m^3/s (0.002 gpm), was well below both the technical specification limit of 1 gpm and the threshold value of leakage that could be detected by the plant leakage detection methods. The leak was detected by the accumulation of boric acid crystals on the floor beneath the pressurizer. The boric acid corrosion removed about 18% of the low–alloy steel base metal wall thickness. If the leakage had continued undetected, the boric acid would have caused further degradation of the base metal. Therefore, it is important that nuclear power plants use monitoring procedures that will detect boric acid leakage before it causes significant degradation to the reactor coolant pressure boundary. Boric acid corrosion is discussed further in Section 7.4.6.

3.6 Inservice Inspection and Surveillance Methods

The pressurizer is subject to a number of inspections both before and at intervals during its operating lifetime. Ultrasonic, radiographic, and dye penetrant methods are typically used for the fabrication inspections.

Inservice inspections are performed at periodic intervals during service in accordance with Section XI of the ASME Code.[28] The areas on the pressurizer that are currently being inspected are listed in Table 3.4. In addition, system leakage tests are required at each refueling outage, and one system hydrostatic test is required per inspection interval, both with visual inspections. Thus, there is a good chance that any degradation problems will be detected before they become a major safety risk, and the condition of the pressurizer will be known as its lifetime progresses so that life extension can be better assessed.

However, the twenty–two heater sleeve failures at Calvert Cliffs Unit 2 were a surprise, even though visual inspection of all heater penetration welds is required during each inspection interval.[28] Thus, current inspections (locations, frequencies, and techniques may not be completely adequate to support license renewal and improved inspection techniques may be required, both to detect and quantify metal damage and to estimate the remaining life before failure. In addition, the inspection locations and frequencies may need to be revised.

A survey of both existing and new methods of inservice inspection is reported in Chapters 11 and 12 of Volume 1.[2] The Surry 1 life extension study[16] recommends that (a) volumetric and surface examinations of the sensitized safe ends of the spray and surge nozzles be conducted on a regular basis to monitor for IGSCC, (b) an on–line transient monitoring system be developed to better understand actual fatigue loadings, and (c) advanced ultrasonic inspection techniques be investigated. The inspection technique that holds the most promise for future damage detection at all

Table 3.4. Inservice inspections[28] at important pressurizer locations

Location	Method	Extent and Frequency: First Interval	Extent and Frequency: Successive Intervals
1. Shell–to–head welds			
a. Circumferential	Volumetric	Both welds 100% of length	Both welds 100% of length
b. Longitudinal	Volumetric	One ft of length at intersection with circumferential weld (all welds)	One ft of length at intersection with circumferential weld (one per head)
2. Head welds	Volumetric	All welds 100% of of length	One weld per head
a. Circumferential			
b. Meridional			
3. Nozzle–to–vessel welds	Volumetric	All nozzles	All nozzles
4. Nozzle inside radius section	Volumetric	All nozzles	All nozzles
5. Heater penetration welds	Visual; external surfaces	All nozzles	All nozzles
6. Safe–end welds			
a. ≥NPS[a] 4	Volumetric and surface	All welds	All welds
b. <NPS 4	Surface	All welds	All welds
c. Socket welds	Surface	All welds	All welds
7. Bolts and studs			
a. >2 in. in diameter	Volumetric	All bolts and studs	All bolts and studs
b. ≤2 in. in diameter	Surface	All bolts and studs	All bolts and studs

a. NPS = nominal pipe size.

susceptible locations is the ultrasonic method. The Westinghouse Owners Group research program on ultrasonic examination of dissimilar weld metals may provide useful information. Reference 46 describes an automated ultrasonic imaging system developed by Combustion Engineering that apparently distinguishes between IGSCC, weld root geometry, and counterbore reflected signals, which may cause false crack indications.

However, a suitable method to accurately find and adequately characterize fatigue damage has not yet been developed and implemented. An accepted method to determine the existence and extent of damage from thermal embrittlement also is needed. Detailed inspection plans with reliable nondestructive techniques for all potentially degraded locations should be developed to verify the safety of the pressurizer for continued operation during and beyond the design lifetime of 40 years.

3.7 Summary, Conclusions, and Recommendations

The pressurizer is a pressure vessel constructed, and inspected at frequent intervals, according to the ASME Code. It is not subjected to high neutron fluence, and the RCS coolant with which its internal surfaces are in contact is of high purity. The major problems associated with this system have been the safety and relief valves, which have failed to seat properly, leaked, failed to lift, had their set points drift, or been improperly installed, repaired, or inspected. [42,43,44,47,48] The valve reliability question is an ongoing operational challenge throughout plant lifetime but is not necessarily a license-renewal issue and has not been addressed here.

The aging degradation mechanism that is pervasive throughout PWR pressurizers is fatigue. Low-cycle fatigue damage is caused by plant heatup/cooldown cycles, plant unloading and loading at power, step-load increases and decreases, reactor trips, hydrotests, etc. The surge-line nozzle and thermal sleeve are particularly affected by the insurge of relatively cooler hot-leg coolant and/or outsurge of pressurizer fluid associated with power changes. The spray-line head, the nozzle, and the thermal sleeve are very susceptible to fatigue damage caused by the subcooled spray actuations associated with power changes. The pressurizer walls may be susceptible to both the low-cycle fatigue damage caused by the plant operational transients and the high-cycle thermal fatigue caused by (a) thermal loads imposed by the subcooled spray on the pressurizer walls, (b) sloshing of the liquid at the steam-water interface, and (c) water-level changes caused by insurges, outsurges, and heater actuations. The key fatigue degradation sites are calculated to have high cumulative fatigue usage factors and include the pressurizer walls near the usual steam-water interfaces, the spray head, the spray- and surge-line nozzles, and the thermal sleeves. The cast stainless steel spray heads are also susceptible to thermal aging (embrittlement) and erosion. The heater sheaths and sleeves are susceptible to wear caused by thermally induced rubbing and possibly stress corrosion cracking. Pressurizer manway bolts can and have been damaged by leaking primary coolant, which caused stress corrosion cracking. Leakage of borated coolant can also cause corrosion and wastage of the nearby low-alloy steel base metal. Potential failures include ductile tearing and through-wall cracks, leading to (a) leakage of the primary coolant (pressurizer walls near the usual steam-water interface and/or surge- or spray-line nozzles), (b) excessive erosion and/or cracking of the spray heads, (c) heater sheath and/or sleeve cracks, and (d) manway cover leakage.

Other than the associated valves, at least two subcomponents can be expected to require replacement. These are (a) the heater elements, which can be replaced at refueling outages on a regular basis (in fact, the original designs facilitate ease of maintenance), and (b) the spray head, which can be replaced by a relatively minor operation. Otherwise, the pressurizer may be a good candidate for life extension, using additional analyses and inspections as outlined below.

Critical degradation sites, stressors, degradation mechanisms, potential failure modes, and appropriate inservice inspection methods for pressurizers are listed in Table 3.5.

Several supporting analyses and tests will be required to determine the residual life of the pressurizer. Inclusion of additional requirements in the ASME Code, Section XI,[28] would be appropriate. The following are the recommendations for more detailed analyses and tests:

1. Reanalysis of the fatigue life at the locations with high fatigue usage factors will be necessary, possibly with more refined thermal models and with better definition of actual temperatures and temperature change rates during transient conditions. This should include better definition of the high-cycle events, such as verifying that sloshing does or does not occur, and realistic numbers of spray cycles. The MIT experimental results can probably be used to quantify the accuracy of

pressurizer transient prediction models. The location of critical welds, such as at the steam-water interface, would have to be determined on a case-by-case basis, depending on the manufacturing technique.

2. In conjunction with Item 1, there also must be justification that the fatigue curves used in any revised fatigue analysis are applicable to metal exposed to a PWR environment. Corrosion fatigue curves, including the high-cycle region, should be developed. (This item is applicable to all primary system components.)

3. A comprehensive inspection plan to detect cracks will be necessary (probably using current ultrasonic test methods). A program to evaluate crack growth will also be necessary for these locations where cracks are found. Development of a technique to monitor for cracks at heater sleeve locations is needed. An inspection plan to monitor spray head erosion is also recommended.

4. Adequate monitoring techniques that will detect boric acid leakage and corrosion before it causes significant degradation of the primary coolant pressure boundary should be developed.

5. The cast stainless steel spray heads may be susceptible to erosion and thermal embrittlement during operation. However, this problem can be solved by replacing the degraded spray heads.

Table 3.5. Summary of degradation processes for pressurizers

Rank	Degradation Site	Stressors	Degradation Mechanisms	Failure Modes	ISI Method
1	Vessel shell near steam–water interface	Thermal and mechanical stresses caused by plant operational transients, water level changes (due to insurges, outsurges and heater actuations), sloshing, subcooled spray impact and hydrotests; PWR coolant	Fatigue (possibly corrosion assisted)	Crack leading to leak	Volumetric
2	Spray line nozzle	Thermal and mechanical stresses caused by plant operational transients, spray actuations and hydrotests; PWR coolant	Fatigue (possibly corrosion assisted)	Crack leading to leak	Volumetric, surface
3	Surge line nozzle	Thermal and mechanical stresses caused by plant operational transients, insurges, outsurges and hydrotests; PWR coolant	Fatigue (possible corrosion assisted)	Crack leading to leak	Volumetric, surface
4	Heater sheathes and sleeves	Residual stresses, PWR coolant, thermally induced rubbing	SCC, wear	Crack leading to leak or metal loss	Visual for external penetration welds
5	Manway bolts	Steam leakage	SCC	Bolt breakage, leak	Volumetric (>2 in.), visual ($\leq$2 in.)[a]
6	Supports (keys, skirts and shear lugs)	Thermal stresses, seismic events	Fatigue	Crack leading to loss of support; overstress of piping	Volumetric, visual
7	Thermal sleeve	Flow–induced vibration, thermal stress	Fatigue	Loss of thermal sleeve to protect nozzles	None
8	Spray head	Spray flow, temperature, thermal stress caused by spray actuation	Erosion, embrittlement, fatigue	Loss of spray capability	None
9	Heater elements	Temperature	Burnout	Loss of heating capability	None

a. One inch = 25.4 mm.

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4. PRESSURIZED WATER REACTOR SURGE AND SPRAY LINES AND NOZZLES

E. A. Siegel and M. H. Bakr

The pressurized water reactor (PWR) components discussed in this chapter are the pressurizer surge and spray lines and nozzles. Each of the components is subject to thermal loading conditions that may result in significant fatigue damage. In general, the components and their potential for fatigue-related degradation are common to the three major PWR nuclear steam supply system designs: Combustion Engineering, Westinghouse, and Babcock & Wilcox. This chapter is based on studies performed by Combustion Engineering.[a,b,c] However, qualitative comparisons to the Westinghouse and Babcock & Wilcox PWR designs are also included where appropriate. This chapter includes (a) a description of the system, (b) identification of major stressors in the system, possible degradation mechanisms, and potential failure modes, (c) discussion of current inspection methods, and (d) conclusions and recommendation for extending system life.

4.1 Description

The pressurizer surge line is typically a 250- to 350-mm- (10- to 14-in.-) diameter Schedule 160 Type 316 stainless steel pipe that connects the bottom of the pressurizer to the hot leg primary piping. The surge lines were designed with the assumption that coolant surges would sweep the full cross section of the piping, but the actual flow pattern appears to be stratified. The horizontal configuration of much of the surge line routing and the generally low flow rates in the system facilitates flow stratification which can cause severe thermal loadings on both the piping and nozzles.

The upper portion of the pressurizer main spray line is typically a 50- to 100-mm- (2- to 4-in.-) diameter Schedule 120 Type 316 stainless steel pipe that connects the top of the pressurizer to one or more cold legs in the primary piping. An auxiliary spray line is also used in some cases, which ties into the main spray line near the spray nozzle. The spray line may also be exposed to severe thermal loadings because of the horizontal configuration of the upper portion of the spray line [typically 3.1- to 4.6-m (10- to 15-ft) long] and because of the potential for stratified steam and water flow.

As discussed in Chapter 3, the pressurizer controls the reactor coolant system (RCS) pressure by maintaining the temperature of the pressurizer liquid at the saturation temperature corresponding to the desired system pressure. Pressurizer temperature is controlled and maintained by heaters and spray. The heaters supply energy to heat the pressurizer liquid to the required temperature and to offset heat losses to ambience. The spray acts to reduce pressure, should it increase during a transient, by injecting cold leg water into the steam space.

Figure 4.1 is a schematic of a portion of a typical Combustion Engineering reactor coolant system, which includes the pressurizer, surge line, main and auxiliary spray lines, and charging lines. Pressure, temperature, and level sensing locations; valves; and bypass lines are also shown in Figure 4.1. The figure illustrates the connection between the bottom (liquid-filled part) of the pressurizer and the hot leg, as well as the basic connecting systems from the various cold leg primary piping locations and the charging pumps, through the pressurizer main or auxiliary spray lines, and into the top of the pressurizer. An auxiliary spray line from the charging system permits pressurizer spray during plant conditions such as heatup and cooldown when some of the reactor coolant pumps (RCPs) are not operating and, therefore, main spray may be unavailable.

When the steam demand from a nuclear power plant is increased, the average reactor coolant temperature is raised in accordance with a coolant temperature program. Figure 4.2 illustrates a typical plant temperature control program, where at any given steam generator power output T_{cold} is the primary fluid inlet temperature into the reactor vessel and T_{hot} is the outlet temperature. T_{avg} is the average temperature in the

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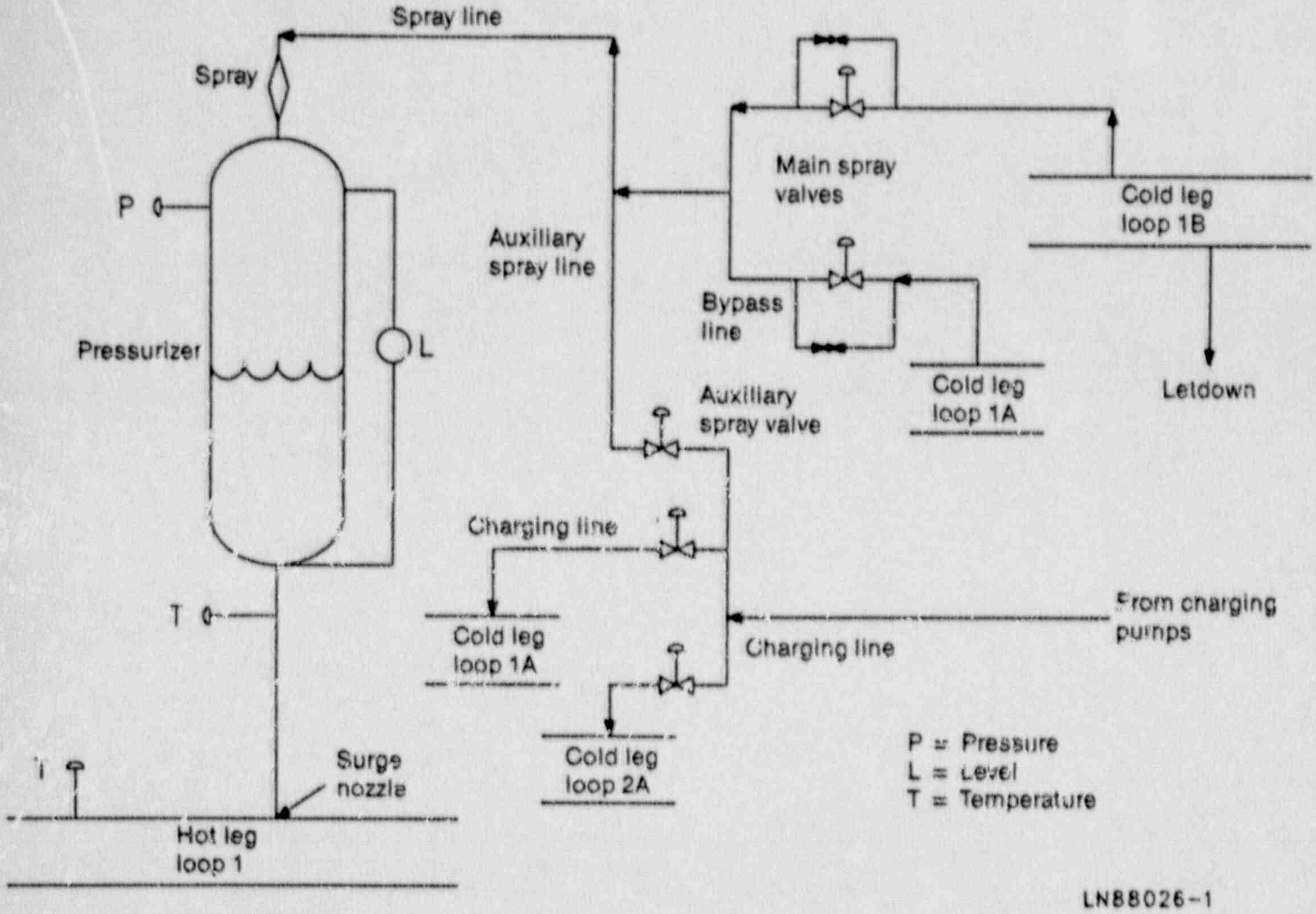

Figure 4.1. Pressurizer spray and surge systems.

reactor core. The expanding coolant from the reactor coolant piping hot leg enters the bottom of the pressurizer through the surge line, compressing the steam and raising the system pressure. The increase in pressure is moderated by the condensation of steam during compression and by the decrease in average liquid temperature in the pressurizer. The pressurizer temperature decreases as a result of the insurge of cooler surge line water. A typical value for the normal operating pressurizer temperature at full power is 343°C (650°F), with the cold and hot leg temperatures being about 296°C (564°F) and 327°C (621°F), respectively (see Figure 4.2). Also, the water temperature in the surge line may be slightly cooler than the hot leg temperature during some flow conditions because of the heat loss to the containment building. When the transient pressure reaches an upper limit, the pressurizer spray valves open, spraying coolant from the RCP discharge (cold leg) into the pressurizer steam space. The relatively cold spray water condenses more of the steam and, therefore, limits the system pressure increase.

When the steam demand is decreased, the pressurizer heaters are used to keep the primary coolant system pressure constant.

Figure 4.3 depicts a typical pressurizer surge line. The surge piping typically begins in a vertical run out of the pressurizer and then runs in a horizontal or near-horizontal plane for most of its length. The surge line terminates in a single surge nozzle, which is located in one of the hot legs. The surge lines in Westinghouse and Babcock & Wilcox plants, as well as in some Combustion Engineering plants, are made of wrought stainless steel piping and are subject to the same degradation phenomena. In the remaining Combustion Engineering plants, the surge line is made of cast

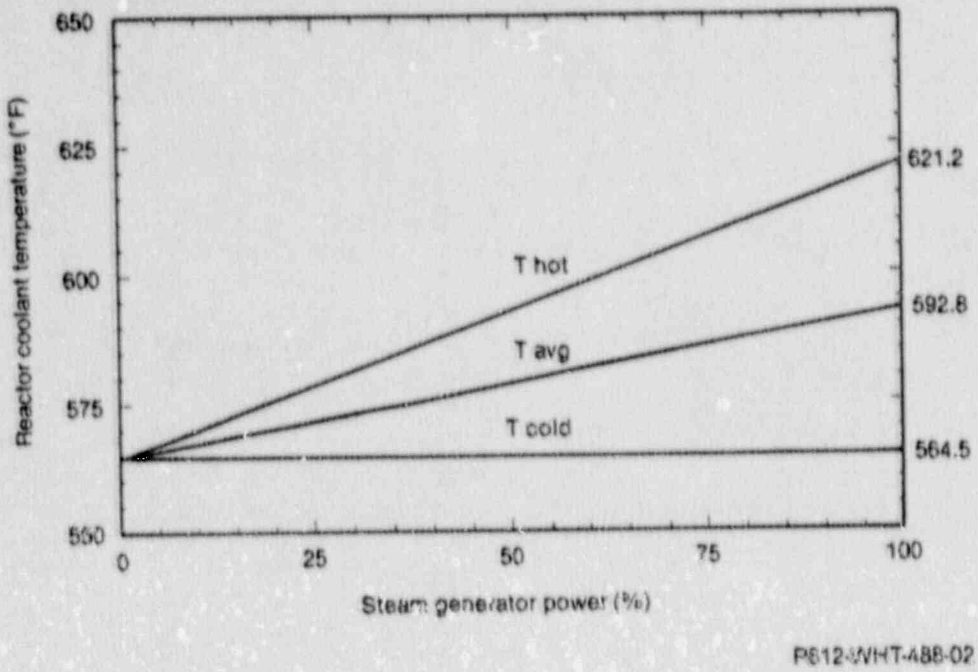

Figure 4.2. Typical PWR temperature control program.

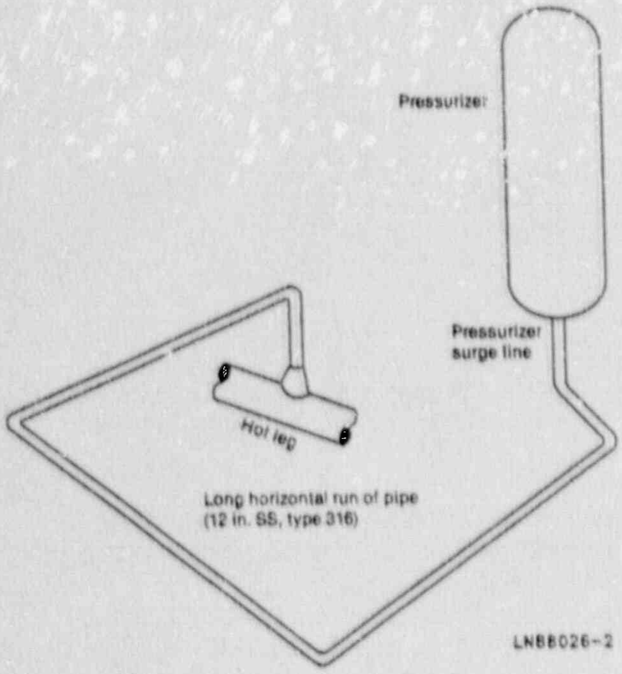

Figure 4.3. Typical pressurizer surge line layout.

stainless steel (CF8M) and is subjected to the added degradation of thermal aging. The hot leg piping material is different for the three suppliers. The Westinghouse hot leg piping is stainless steel. The Combustion Engineering and Babcock & Wilcox pipings are carbon steel with stainless steel cladding, and include a stainless-steel safe end between the surge line and nozzle. Therefore, the weld between the safe end and nozzle is a dissimilar metal weld. A sketch of a Combustion Engineering surge nozzle is shown in Figure 4.4.

Two of the reactor coolant pump cold legs supply the pressurizer spray to the spray nozzle. Automatic main spray valves control the amount of spray as a function of pressurizer pressure. Components of the pressurizer

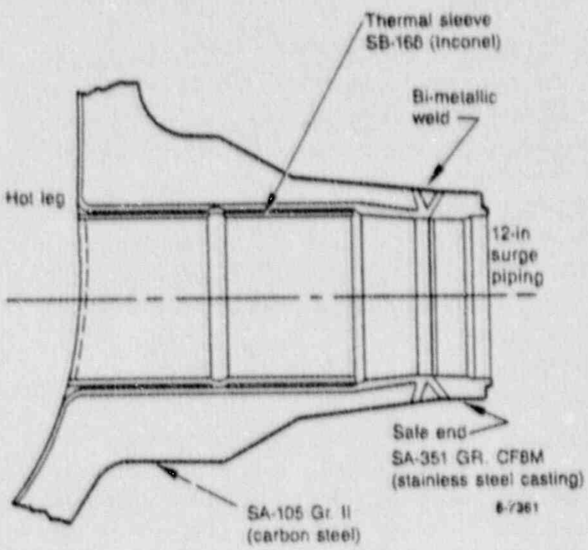

Figure 4.4. Typical Combustion Engineering surge nozzle at hot leg (12 in. Schedule 160).

spray system are sized to use the differential pressure between the reactor coolant pump discharge and the pressurizer to pass the amount of spray required to maintain the pressurizer steam pressure during normal operational transients.

A small, continuous flow, referred to as bypass flow, is maintained through the spray line when all reactor coolant pumps are running, even when the main spray valves are closed. The flow bypasses the main spray valves as indicated in Figure 4.1, and serves to keep the spray piping and nozzle at a constant temperature in order to reduce thermal transients during main spray usage. The bypass flow also serves to keep the chemistry and boric acid concentration of the pressurizer water the same as that of the rest of the reactor coolant loops.

The pressurizer spray line connects two of the cold legs to the top of the pressurizer through vertical and horizontal pipe runs in Westinghouse and Combustion Engineering plants. But in Babcock & Wilcox plants, the spray line connects to only one cold leg. As shown in Figure 4.1, the auxiliary spray line ties into the main spray line. Figure 4.5 depicts a typical pressurizer spray line. The pressurizer spray lines are stainless steel in all PWR plants. The spray piping to the safe end welds at the spray nozzle are dissimilar metal welds on all three vendor designs. A typical Combustion Engineering spray nozzle is shown in Figure 4.6.

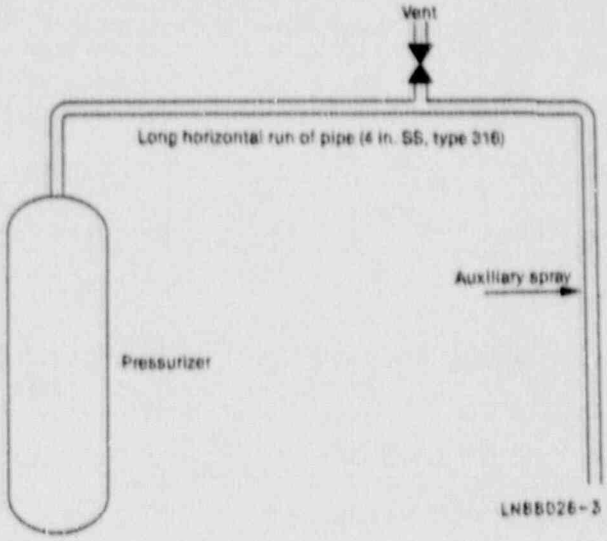

Figure 4.5. Typical pressurizer spray line layout.

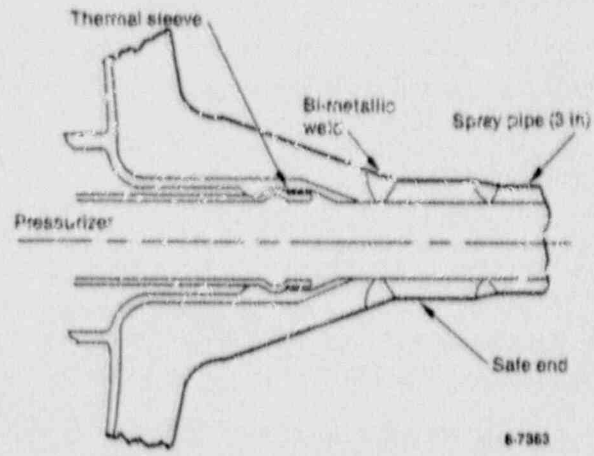

Figure 4.6. Typical Combustion Engineering spray nozzle (3-in. Schedule 160).

4.2 Stressors and Degradation Sites

4.2.1 Surge Line and Nozzle. The principal source of fatigue damage in the pressurizer surge piping and nozzles is the thermal stress loadings associated with normal plant operation. Typical design-basis thermal transients for Combustion Engineering plants (such as plant heatup and cooldown, plant leak testing, plant trips, and other plant operational functions) are listed in Table 4.1 with their specified cycles. Figures 4.7 and 4.8 provide typical temperature and pressure versus time curves, illustrating some of the major transients. Figure 4.7 illustrates a conservative envelope of the reactor coolant temperature and pressure profiles during a plant leak test. Figure 4.8 illustrates the surge nozzle temperature and pressure transients encountered during typical plant heatup and cooldown events. Note that the transient descriptions are for fatigue evaluations only and may not represent actual plant operations.

Design calculations performed in accordance with the American Society of Mechanical Engineers (ASME) code have demonstrated that those design-basis transients result in acceptable fatigue usage during a 40-year operating life; i.e., the calculated fatigue usage factor is less than the allowable ASME code value of 1.0. A typical maximum design-basis cumulative fatigue factor for the surge line and nozzle for Combustion Engineering plants is 0.2. The design-basis fatigue usage factor will differ for the Westinghouse and Babcock & Wilcox plants but will also be below 1.0. For example, the design-basis usage factor calculated for a Westinghouse surge line and nozzle is approximately 0.7.[1] Actual fatigue usage is, of course, a function of plant operational data rather than the design assumptions.

Table 4.1. Typical design–basis thermal transients

Transient	Description	Specified Cycles
Plant heatup	See Figures 4.2 and 4.8	500
Plant cooldown	See Figures 4.2 and 4.8	500
Plant leak test	See Figure 4.7	200
Normal operation steady state	T = 327.3°C (621.2°F) P = 15.51 MPa (2250 psi)	
Plant trip, loading, unloading	—[a]	30500[c]
10% load increase, decrease	—[b]	25000
Normal variation up or down	P = 15.51 ± 0.69 MPa (2250 ± 100 psi) T = 327.3 ± 11°C (621.2 ± 20°F)	10^6

a. From an initial temperature of 345°C (653°F), the fluid undergoes a step decrease in temperature of 61°C (110°F) and remains at the new temperature for a period of time sufficient for the metal to reach equilibrium followed by a step increase to the initial temperature. The total number of occurrences is 30,500 cycles, and it includes 500 trips, 15,000 loadings, and 15,000 unloadings (load change > 10%). The flow and pressure associated with this transient are 13.6 kg/s (30 lbm/s) and 15.51 MPa (2250 psia), respectively.

b. From an initial temperature of 345°C (653°F), the fluid undergoes a step decrease in temperature of 33°C (60°F) and remains at the new temperature for a period of time sufficient for the metal to reach equilibrium, followed by a step increase to the initial temperature. The total number of occurrences is 25,000 cycles. The flow and pressure associated with this transient are 13.6 kg/s (30 lbm/s) and 15.51 MPa (2250 psia), respectively. This transient is categorized as a normal condition.

c. This specified transient number of 30,500 includes many plant transients that are grouped here for convenience.

In addition to the design–basis thermal stress cycles, other surge piping and nozzle thermal loadings have been hypothesized, which may significantly affect the fatigue of those components. The most important loading is caused by thermal stratification. Thermal stratification can occur in the horizontal sections of the surge line when cooler, heavier water from the hot leg flows under the warmer, lighter coolant from the pressurizer or possibly when localized cooling (toward containment ambient temperature) and fluid separation occurs. Thermal stratification will result in thermally induced bending stresses which can impact the fatigue life of the surge line and nozzle (the upper portion of the piping is hotter than the bottom and the pipe may deflect up or down depending on the pipe supports when the flow is stratified). Thermal stratification also causes a phenomenon known as "thermal striping" which is the high cycle thermal fatigue caused by the wavy nature of the interface between the two stratified fluid layers. The potential for thermal stratification is greatest during heatup and cooldown because the difference between the pressurizer and hot leg temperatures is largest then. The potential for stratified flow also increases as the insurge or outsurge flow rates decrease.

Prior to start of the reactor coolant pumps, the temperature of the coolant in the hot legs is typically about 55°C (130°F), and the temperature of the coolant in a pressurizer with a steam bubble can be as high as the saturation temperature [which corresponds to the minimum pressure, typically 2.24 MPa (325 psi), at which the reactor coolant pumps can be operated]. Therefore, the difference between the coolant temperature in the pressurizer and in the hot leg during heatup may be as high as 180°C (325°F). The maximum temperature difference can also be as high during reactor scram and

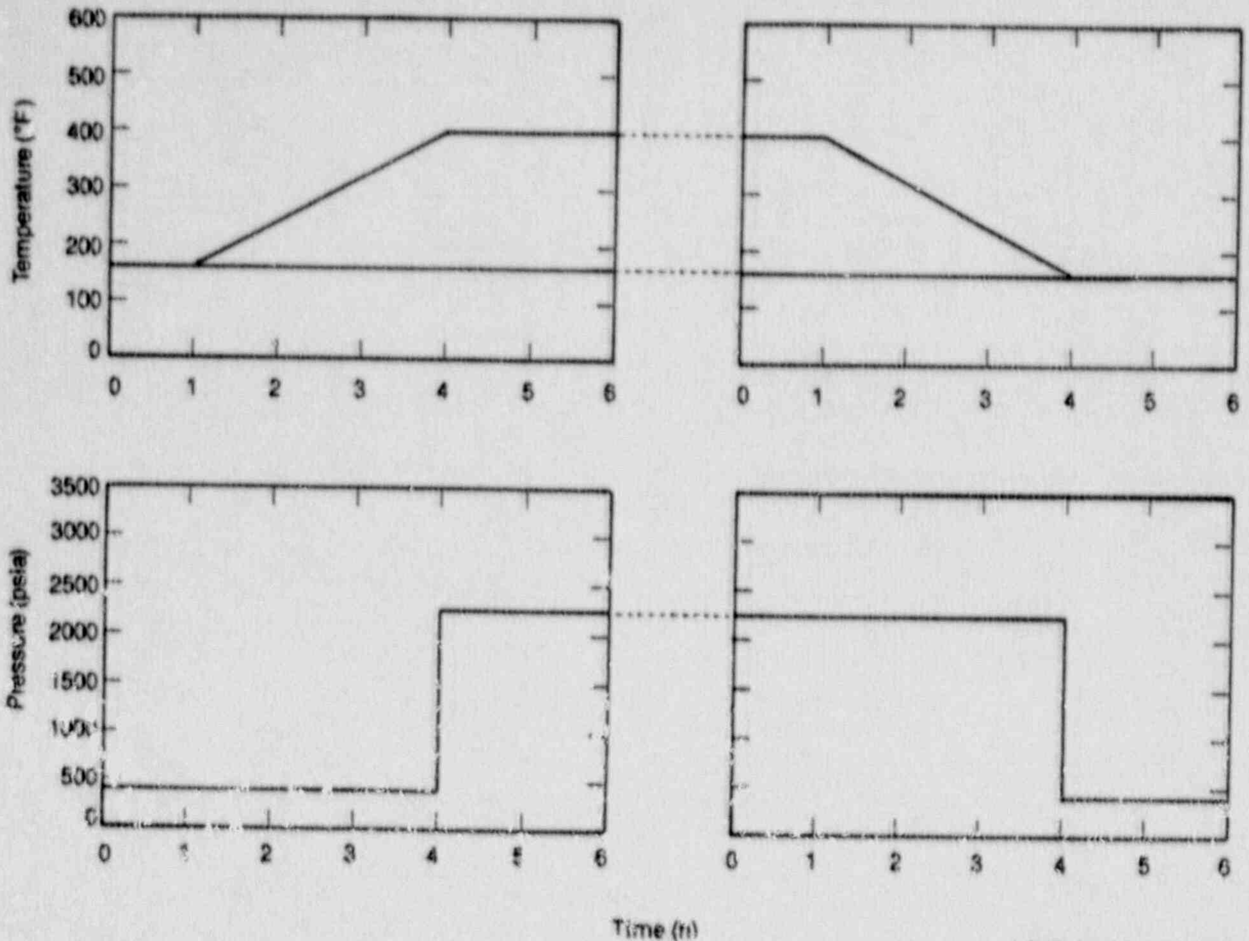

Figure 4.7. Plant leak test, simulated for fatigue evaluations only.

cooldown as during heatup. Several insurges to and outsurges from the pressurizer generally take place during heatups, cooldowns, and reactor scrams.

The pressurizer temperature is about 343°C (650°F) during full-power operation, and the difference in temperatures between the pressurizer and the hot leg is about 28°C (50°F). The flow in the surge line is small and equal to the bypass flow in the spray line (typically 1.5 gal/min) and, therefore, the flow is generally stratified. However, the corresponding thermal stresses will be lower than during heatup and cooldown because the difference in temperature between the stratified flow layers is relatively small.

Thermal stratification was measured in a Babcock & Wilcox unit in Germany, where temperature swings in the surge line reached 180°C (325°F).[2] Four U.S. utilities have also measured significant surgeline stratification. At one plant, the thermal stratification caused the horizontal portion of the surgeline to deflect downward, contacting the pipe whip restraints and resulting in permanent deformation of the pipe.[11] At another plant, the thermal stratification caused displacements as great as 76 mm (3.0 in.) during heatup and cooldown; the displacement appeared to vary with the temperature difference between the pressurizer and hot leg.[a] One utility has limited the maximum allowable temperature difference between the pressurizer and the hot leg to about 110°C (200°F) to reduce fatigue damage caused by stratification. Qualitative data from tests in France and Germany also indicate that surge line flow stratification may occur under certain low-flow conditions.[b]

The unexpected surge line movements and the resulting permanent piping deformation have raised

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b. T. Griesbach, private communication, EPRI.

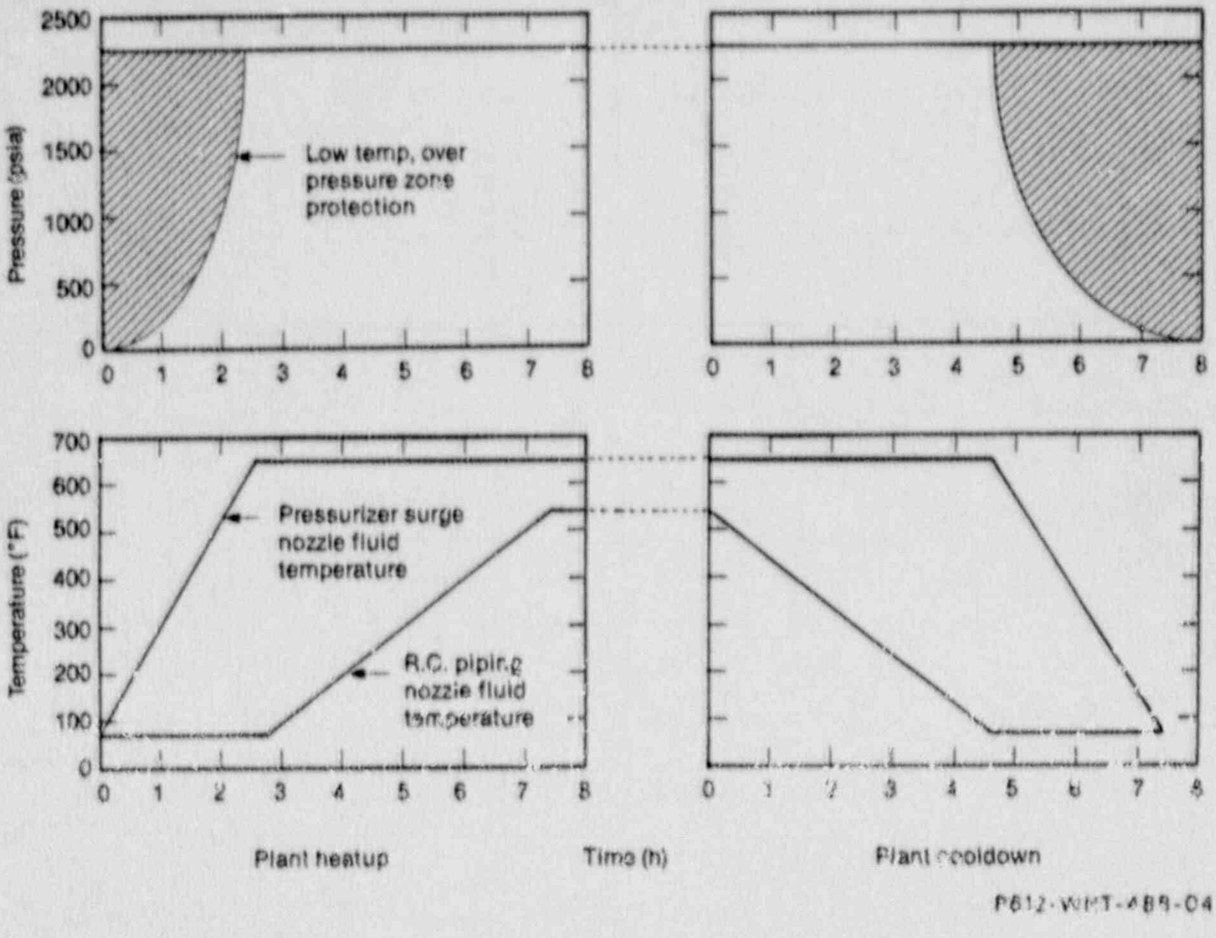

Figure 4.8. Simulated surge nozzle transient—heatup and cooldown for fatigue evaluation only.

concerns about the validity of the original design fatigue analyses for the surge lines. Therefore, the USNRC has requested the licensees of operating PWR plants to demonstrate that the pressurizer surge line meets the latest ASME Section III requirements (incorporating any high-cycle fatigue) for the licensed life of the plant, considering the fatigue damage caused by thermal stratification and thermal striping.[15]

Localized surge line cooling may lead to two interrelated types of thermal loadings. As discussed above, a local area of stratified fluid may develop with warmer fluid in the upper portion of piping and cooler fluid in the lower portion of piping. The second type of localized thermal loading of the surge line is caused by a slug of locally cooled water that moves through the piping. That cooler slug may pass through the hot leg surge line nozzle during pressurizer outsurges, and impose thermal shock stress cycles on the nozzle as well as the surge piping. Also, the cooler water from the surge piping may pass through the pressurizer surge line nozzle during a pressurizer insurge and impose thermal shock stress cycles on that nozzle. The severity of that stressor depends on the degree of local cooling and the frequency of insurges and outsurges. There are more outsurges than insurges from the use of main spray. Whenever mainspray is used while the pressurizer level remains constant, or decreases, there is an outsurge. During changes in power level, there is an equal number of outsurges and insurges as power levels are reduced and then increased. The occurrence of relatively cold slugs of water is based on qualitative evaluations and has not been quantified.[a]

Flow-induced vibration is another common stressor that affects components such as thermal sleeves, installed to protect the nozzle from thermal shock. That stressor could lead to fatigue failure of the thermal sleeve and the nozzle, with the possibility of the thermal sleeve breaking loose and moving through the piping system.

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a. T. Griesbach, private communication, EPRI.

Thermal aging of the cast–stainless steel surge lines is determined by the temperature of the reactor primary coolant, and the ferrite content and distribution in the microstructure. Since the temperature of the coolant in the pressurizer is higher than that in the hot leg, the portion of the surge line near the pressurizer will experience a higher degree of thermal embrittlement.

4.2.2 Pressurizer Spray Line and Nozzle. Typical design–basis thermal transients for PWR spray lines and nozzles include the same plant heatup and cooldown, plant loading and unloading, and other plant operational functions as discussed in the previous section. Design analyses performed in accordance with the ASME code have demonstrated that those design–basis transients result in acceptable fatigue usage during a 40–year plant life. A typical maximum design–basis cumulative fatigue factor for the pressurizer spray piping and nozzle for a Combustion Engineering plant is 0.9. The design–basis fatigue usage factor will differ for the Westinghouse and Babcock & Wilcox plants, but is also below 1.0.

In addition to those typical design–basis transients, certain other thermal transients have the potential to affect the spray line and nozzle fatigue aging. When the pressurizer spray system was designed, it was assumed that spray would be applied in a continuous manner during plant cooldowns. However, in some cases, the spray is applied in an on–off manner. On–off use of the pressurizer spray will result in more frequent thermal stress cycles than will result from one continuous spray.

Reactor coolant system flow and the reactor vessel pressure drop decrease when the first reactor coolant pump is tripped during cooldowns. Since the pressure drop across the reactor vessel provides the driving head for both main and bypass sprays, bypass flow decreases as the driving head is reduced. In fact, the bypass flow can decrease as the pressure differential decreases to the point that it is no longer sufficient to maintain the uppermost horizontal section of the spray line full of water. If the main or auxiliary spray is not used continuously, pressurizer steam will fill the upper cross–sectional area of the horizontal spray piping while relatively cool water flows along the lower cross section, thereby creating a stratified steam/water flow condition. Further reduction of the number of operating reactor coolant pumps causes the bypass flow to terminate and a no–flow condition is created in the spray piping. At this point, steam fills the spray nozzle and piping, moving to an elevation equivalent to the pressurizer level. Although no bypass flow is present, auxiliary spray is available through the charging system. Main spray may also be available if the main spray valves are opened. The on–off use of main or auxiliary spray flow during periods when no bypass flow is available causes intermittent no–flow, stratified flow, or full–flow conditions. That results in thermal cycling and fatigue of the piping. The various stages of spray piping flow that may occur during a plant cooldown or heatup are depicted in Figure 4.9.

Thermal cycling may also occur without spray operation when a steam bubble is formed in the pressurizer, and steam enters the spray piping during the plant heatup. A thermal cycle then occurs when a sufficient number of reactor coolant pumps (RCPs) are started to provide the driving head for a marginal amount of bypass flow. Another thermal cycle occurs when additional RCPs are started and provide enough driving head for the bypass flow to fill the horizontal pipe and eliminate the stratified flow. In summary, spray system thermal cycling can result from cyclic or throttling use of the main or auxiliary spray, or from altering the number of operating RCPs without maintaining full–pipe flow conditions. The phenomenon of flow stratification in the piping of the pressurizer spray system was identified during startup testing at some PWR plants.[a]

Alternating steam and water cycles during cyclic system operation may subject the upper portion of the spray piping and the spray nozzle to typical temperature differentials in the range of about 40 to 300°C (100 to 530°F), with resultant thermal shock loadings. These same temperature differences can exist in a top to bottom stratified flow condition under certain low spray flow operations. However, the pressurizer spray nozzle cannot be subjected to stratified flow loadings and is, therefore, not as limiting as the upper horizontal portion of the spray piping. The thermal shock loadings can be evaluated using the classical ASME Code Section III methods,[3] whereas, stratified flow loadings produce beam–bending type behavior and require three–dimensional modelling to evaluate. The shape of a typical spray line subjected to stratified flow is shown in Figure 4.10. The distribution of bending stress in the pipe for that type of loading can be calculated by finite element analysis and an example result is shown in Figure 4.11. That analysis takes into account the thermal conductivity of the piping material.

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a. Combustion Engineering *Pressurizer Spray System Thermal Fatigue Evaluation*, CE NPSD–261 prepared for the Owners Group, December 1984.

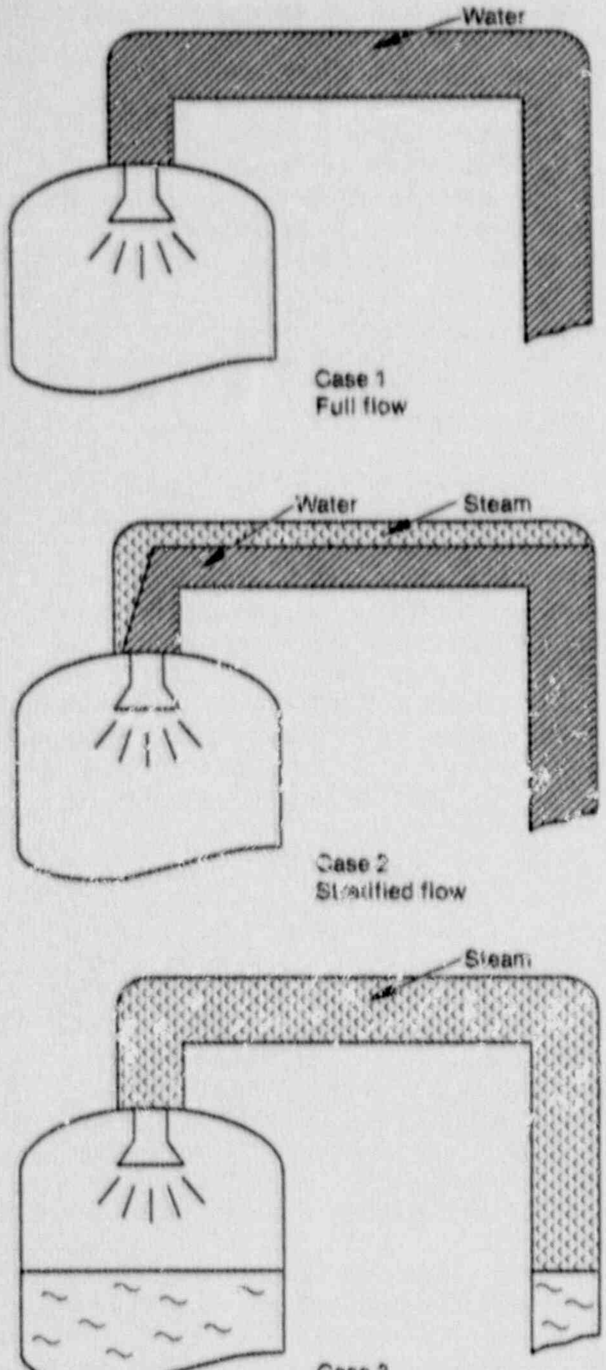

Figure 4.9. Various pressurizer spray system flow conditions.

One major difference between the thermal shock loading and the stratified flow loading is the duration of the stressed conditions. Thermal shock loadings tend to reflect very fast stress patterns, where peak stresses are reached quickly and dissipate quickly.

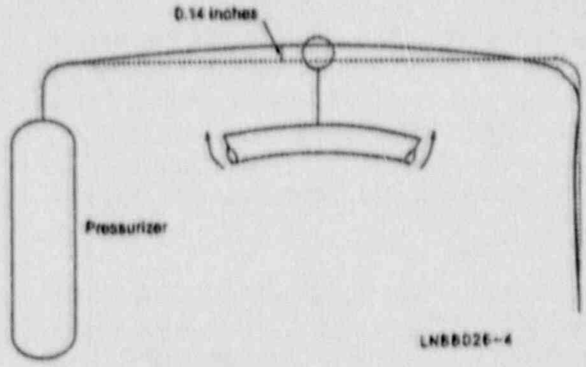

Figure 4.10. Shape of spray line subject to stratified flow conditions.

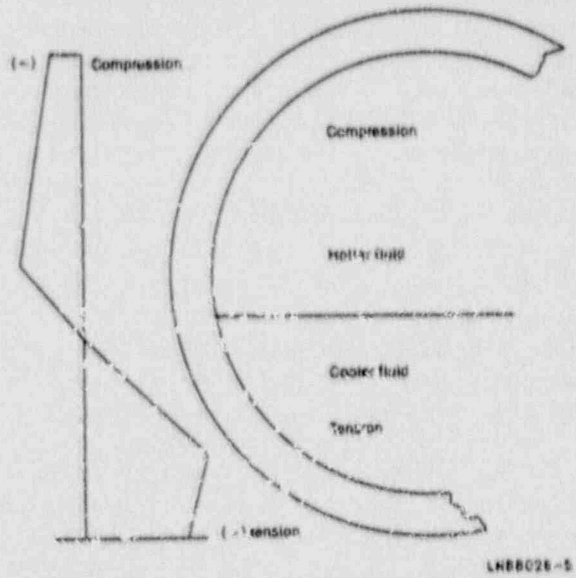

Figure 4.11. Axial stress distribution in a pipe caused by stratified flow loading.

Stratified flows, because of the through–wall nature of the loading, tend to build up more gradually and last as long as the loading condition is applied. Figure 4.12 shows stress–versus–time plots for hypothetical thermal shock and stratified flow loadings. The thermal shock load can be a crack initiator, but it affects only a small portion of the wall thickness and, therefore, does not tend to extend an existing crack. However, the stratified flow load affects the entire wall thickness and, therefore, can drive or propagate an existing crack. One additional difference between the loading cases is their effect on the fatigue life of the component. Stratified flows produce bending moments in piping and pipe elbows. Through–wall bending stresses have a more severe impact on fatigue usage than thermal shock–type skin stresses. A spray line fatigue analysis has been performed for both types of loadings. The

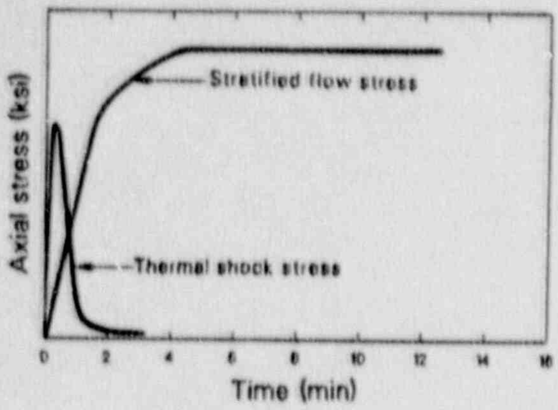

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Figure 4.12. Stress-versus-time profile for hypothetical thermal shock and stratified flow loadings for a given temperature difference, ΔT.

allowable number of loading cycles required to reach a fatigue usage factor of 1.0 has been determined at four locations in a horizontal run of spray piping, as shown in Figure 4.13. The results are presented in Table 4.2 and demonstrate the more severe effects of stratified-flow loadings.

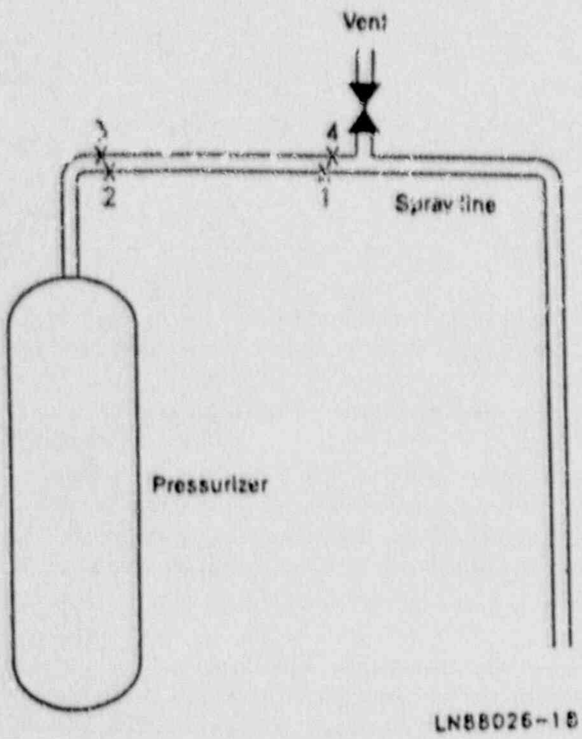

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Figure 4.13. Location on the pressurizer spray line of the fatigue analysis presented in Table 4.2.

One positive aspect of the evaluations is the conclusion that either operational or piping modifications (or both together) can significantly reduce the impact of the loadings on the fatigue life of spray lines. From an operational standpoint, continuous rather than cyclic use of main and auxiliary spray should be practiced during plant cooldowns. That will minimize the total number of thermal loading cycles applied to the spray piping and nozzle. In addition, full pipe flow should be maintained by using main or auxiliary spray whenever there may be insufficient bypass flow to provide full pipe flow. Spray piping modifications can also be made to minimize the potential for stratified flow. A sloped section of pipe can be employed in place of the upper horizontal section of spray piping to help prevent stratified flows. That modification has been made at several plants to ensure sufficient fatigue life in the spray system. For example, a 3-m- (10-ft-) long horizontal section at one plant was rotated 45 degrees to mitigate the thermal loads caused by stratified flows.

Flow-induced vibration is another common stressor that affects components such as thermal sleeves installed to protect the nozzle from thermal shock. This stressor could lead to the fatigue failure of the thermal sleeve and the possibility of the thermal sleeve breaking loose and moving through the piping system.

4.3 Degradation Mechanisms

Fatigue is the main degradation mechanism for the PWR surge and spray lines and nozzles. The design-basis thermal transients listed in Table 4.1 cause both high- and low-cycle fatigue damage. High-cycle fatigue is caused by small temperature changes during normal plant operation (10^6 cycles of ±20°F are assumed for a 40-year plant life) and results in relatively little fatigue damage. Low-cycle fatigue is caused by a combination of transient pressure and thermal stresses and is a much more damaging degradation mechanism.

As discussed above, stratified flows also cause high- and low-cycle fatigue damage to the horizontal portions of the surge and spray lines (see Sections 6.4.2 and 6.4.3) but were not included in the design basis transients. The hot and cold fluid levels present during stratified flow conditions are separated by an interface layer (also called mixing layer) where turbulent mixing of the fluids occurs, and whose height depends upon the mass flow and the differences in the densities of the fluids. The wavy character of the mixing layer causes rapid changes in the temperatures of the inside surface of the adjacent piping. The magnitudes of these temperature changes depend on the surface heat transfer coefficient and the temperature

Table 4.2. Pressurizer spray line fatigue analysis

Loading Description	Maximum Allowable Cycles[a] Location 1	Location 2	Location 3	Location 4[b]
Stratified flow $\Delta T = 175°F$[d]	>10[c]	4,000	6,000	56,000
Stratified flow $\Delta T = 300°F$	1,500	170	6,500	170,000
Stratified flow $\Delta T = 360°F$	400	80	3,500	75,000
Stratified flow $\Delta T = 600°F$	180	25	500	4,700
Full flow[e] $\Delta T = 115°F$	400,000	350,000	310,000	120,000
Full flow $\Delta T = 300°F$	750	500	500	320
Full flow $\Delta T = 600°F$	100	90	90	60

a. Location numbers correspond to points shown in Figure 4.13.

b. Stress concentration effect resulting from vent line intersection is included.

c. Alternating stress is below the endurance limit.

d. ΔT is defined as the temperature difference between the spray fluid and the initial pipe and nozzle temperature.

e. Full flow implies thermal shock conditions.

difference between the hot and cold fluids. Such surface temperature fluctuations are known as thermal striping. Based on the thermal striping experiments performed for LWR feedwater pipings and also for liquid metal fast breeder reactor components, the typical frequency content of the surface temperature fluctuations is in the range of 0.1 to 10 Hz.[9,10] The temperature fluctuations rapidly attenuate with depth, and the bulk temperature of the piping remains unchanged. The bulk material resists the expansions and contractions of the inside surface of the piping and that causes thermal strains. Thus, the pipe inside surface adjacent to the mixing layer is subject to high-cycle fatigue damage which contributes to crack initiation.

Stratified flow causes an azimuthally varying temperature distribution in the pipe wall, which produces through-wall axial bending stresses. The magnitudes of the stresses are determined by the top-to-bottom temperature difference and the height and thickness of the mixing layer. Axial compressive stresses develop in the hot upper region of the pipe, whereas axial tensile stresses develop in the cold lower region of the pipe. The maximum tensile stresses are near the mixing layer. A slight fluctuation in the flow rate causes the mixing layer to rise or lower and changes the distribution of the through-wall bending stresses produced by the stratified flow. Thus, fluctuations in the stratified flow cause low-cycle fatigue damage, which contributes to both crack initiation and growth.

The piping inside surface near the weld is most susceptible to fatigue crack initiation because of the weld geometry, high residual stresses, and imperfections such as porosity and inclusions.[14] If the welds are not ground smooth and flush with the piping surface, a surface stress concentration can cause crack initiation at the weld toe or root. The residual stresses increase the mean stress and, therefore, play a significant role in low-stress, high-cycle fatigue (the fatigue life may be reduced by a factor of two to three). The material properties near weld imperfections may be locally degraded, and this degradation must also be considered. The inside surfaces of the elbow base metal are also susceptible to fatigue cracks because the elbows are likely to be subjected to high stresses. For example, a through–wall fatigue crack in an elbow base metal region subjected to flow stratification caused by valve leakage was detected in the safety injection pipe of one PWR.[12,13] Through–wall axial bending stresses caused by stratified flows can produce circumferential cracks in the horizontal portions of the surge line and spray lines. However, stratified flows have not caused any cracks in the surge and spray lines. Through–wall and shallower circumferential cracks in both the base metal and the welds of PWR and BWR feedwater piping have been observed (see Section 6.5.2).

Procedures for a fatigue analysis of the ASME Class 1 piping and vessel nozzles in nuclear plants are defined by the ASME Boiler and Pressure Vessel Code, Section III. Paragraph NB 3200 contains the fatigue evaluation procedures for vessel nozzles, and paragraph NB 3600 contains the Class 1 piping procedures. The Section III procedures are based on classical elastic stress–strain evaluations. The cumulative effects of non–uniform transient loadings are accounted for by Miner's Law. That approach accounts for accumulation of fatigue damage by linearly summing fractional damage for a series of stress ranges. The cumulative damage fraction is limited to 1.0.

As discussed above, the original Class 1 stress analysis for all nuclear steam supply systems (NSSSs) demonstrate a cumulative fatigue usage factor of less than 1.0. However, those design–basis calculations generally have not considered stratified flow loadings because loads of that type were not recognized and defined at the time of the original design. In fact, estimating the fatigue damage in surge and spray lines subject to stratified flows is difficult for two reasons: complete characterizations of the thermal loads have not been available and the technology to predict crack initiation in the welds is not fully developed. Detailed records of stratified flow transients are not available to properly estimate the fatigue damage. However, on–line monitoring of the coolant temperatures, pressures, and flow rates and pipe wall temperatures at selected sites in the horizontal piping (along both circumferential and axial directions) could provide the data needed to estimate the low–cycle fatigue damage. The on–line monitoring could also identify the sites experiencing significant low–cycle fatigue damage and, thus, provide guidance for the inservice inspection program. Such on–line monitoring of surge lines at several operating PWR plants is currently being performed. It should be pointed out that the on–line monitoring will not provide data on the thickness of the mixing layer or the magnitudes and frequency content of the thermal striping loads. A research program is needed to characterize the thermal striping loads.

Fatigue caused by flow–induced vibrations is another degradation mechanism that affects nozzles protected by thermal sleeves, with the potential for the thermal sleeve to break loose.[6]

The cast stainless–steel surge lines are also subject to thermal aging and will experience a slow reduction in toughness at operating temperatures. Additional information on the thermal aging of cast stainless–steel components is given in Chapters 2 and 3.

4.4 Potential Failure Modes

The potential failure modes resulting from thermal loads on the pressurizer surge and spray line piping and nozzles (discussed above) include fatigue–induced crack initiation and propagation and through–wall leakage. Note that crack initiation from thermal shock, in and of itself, does not result in through–wall leakage. Once a crack is initiated, there must be a loading or stressor to cause the crack to propagate through the entire wall thickness (see Chapter 3, Volume 1, of this report). Loadings caused by thermal stratification can result in propagation of cracks, whereas skin–type loadings caused by thermal shock generally will not cause a surface crack to propagate. A degraded surge or spray line may rupture during an earthquake. A break in a surge or spray line would be an unisolatable breach of the primary coolant pressure boundary and could create a severe thermal–hydraulic transient.

Leak–before–break (LBB) evaluations of typical PWR pressurizer surge lines subjected to the loads associated with normal plant operation and combined with loads from a safe shutdown earthquake, performed in accordance with the NUREG 1061 Volume III guidance, indicate that a double–ended guillotine pipe break is unlikely. However, the occurrence of significant fatigue loadings in the surge and spray lines may preclude the application of the NUREG 1061 LBB methodology[1] for these piping systems. The criteria state that the "LBB approach should not be considered applicable to high energy fluid system piping, or portions thereof, that operating experience has indicated particular susceptibility to failure from the effects of corrosion (e.g., intergranular stress corrosion cracking), water hammer, or low– and high–cycle (that is, thermal, mechanical) fatigue." The LBB evaluations for surge lines need to be modified to include fatigue loads caused by stratified flows. Preliminary analysis at one PWR plant indicates that the LBB approach may still be valid for a surge line subjected to stratified flows.[8] However, the LBB approach should not be applied to small-diameter piping such as spray lines because it is difficult to maintain a sufficient margin between a leakage-detectable crack length and a critical crack length.

There have been no known failures or cracks in the pressurizer surge and spray line piping or nozzles in any PWR. However, stratified flows and thermal striping have caused through-wall thermal fatigue cracks in the welds and stainless steel base metal of the safety injection and residual heat removal piping. In safety injection piping, the cracks were between the safety injection nozzle and the first check valve.[13,18,19] In residual heat removal piping, the cracks were in the horizontal pipe section upstream of the first isolation valve.[20]

An indication of a crack was discovered in a thermal sleeve of a Westinghouse pressurizer surge nozzle. However, later analyses showed that the design of the nozzle at the hot leg end of the surge line is acceptable without a thermal sleeve. The thermal sleeves and the associated attachment welds have been removed in some plants.[21]

4.5 Inservice Inspection and Surveillance Requirements

Inservice inspection (ISI) is required by Section XI of the ASME code. Those requirements include four inspections at 10-year intervals during the 40-year operating life of a nuclear plant. For piping systems, all the weld locations (but not the base metal) where the calculated design-basis stress intensity exceeds 2.4 S_m (S_m is the maximum allowable stress intensity as defined in Section III of the ASME Code) or where the calculated design-basis cumulative fatigue usage factor exceeds 0.4 must be included in the ISI program.[7] All of the nozzle-to-safe end butt welds are also included in the ISI program. The ISI examinations for those locations consist of a 100% volumetric and surface preservice examination of all welds, followed by a 100% volumetric and surface examination of the same 25% of all the butt welds during each of the four 10-year intervals, per ASME Section XI requirements.

As discussed above, stratified flows are likely to cause significant fatigue damage in both the base metal and welds in the horizontal portion of the surge line. In addition, the base metal in the elbows at the end of the horizontal portion is likely to experience fatigue damage. Therefore, the inspection of the welds and base metal in the horizontal portion of the surge line is needed.

Current industry practices for monitoring and recording appropriate thermal transients vary widely. Monitoring and transient recording systems are generally based on existing in-plant instrument availability and location. Available records of the transients causing fatigue damage are generally not sufficient to properly estimate the fatigue usage experienced by the surge and spray lines and nozzles. On-line monitoring of both (a) coolant temperatures, pressures and flow rates, and (b) pipe wall temperatures at the nozzles and at selected horizontal portions of the piping (along both the circumferential and axial directions) during operational transients, thermal shocks, and stratified flows could provide the data necessary to estimate actual low-cycle fatigue damage. Such on-line monitoring of surge lines at several operating PWR plants is currently being performed in response to USNRC Bulletin No. 88-11.[15]

Acoustic emission methods should also be developed for detecting fatigue crack growth in both the base metal and welds of the surge and spray lines. Acoustic emission methods can potentially provide global information regarding defects in the piping and may be capable of detecting the location and growth of small flaws that are not detectable by other nondestructive testing methods. Acoustic emission should be viewed as complementary to inservice inspection methods, not as their replacement.

Fatigue crack detection by acoustic emission depends upon the ability of the instrumentation to detect the acoustic signals caused by crack growth under reactor operating conditions, specifically in the presence of reactor coolant flow noise. The acoustic signal produced by crack growth consists of discrete burst-type sounds with a duration ranging from a few microseconds to a few milliseconds. The source of the signal is determined from the times of signal arrival at several different sensors installed at various locations. However, some test results indicate that the acoustic signal produced during tensile crack growth in Type 304 stainless steel may not be detectable at certain stages of the crack growth.[16] On the other hand, the preliminary results from the inservice acoustic emission monitoring of a Peach Bottom Unit 3 recirculation–bypass line, core spray line, and feedwater nozzle indicate that pipe cracking can be detected using acoustic emission techniques.[17]

4.6 Summary, Conclusions, and Recommendations

A summary of the important degradation sites, stressors and mechanisms, the potential failure modes, and the current ISI methods is presented in Table 4.3. Evaluation of the pressurizer surge and spray line piping and nozzles indicates that stratified–flow conditions may occur and may lead to fatigue damage that can limit the useful life of pressure boundary components. A complete accounting of actual in–plant thermal loadings is needed in order to accurately predict the residual life of those components. Once the loadings are more accurately defined, an appropriate prediction of fatigue life can be made and an appropriate inservice inspection program can be implemented with state–of–the–art techniques.

The conclusions and recommendations related to aging degradation of the pressurizer surge and spray lines and nozzles are as follows:

1. The horizontal portions of the surge line subjected to stratified flows should be analyzed to determine whether a catastrophic rupture rather than a leak–before–break can take place. Stratified flows cause significant fatigue damage to the horizontal portions of the surge line, but were not accounted for in the original design. Results from a recent analysis of one PWR plant suggest that a surge line subjected to stratified flows will leak before it will rupture.

2. The leak–before–break approach may not be workable for small diameter piping such as spray lines that also experience significant fatigue damage caused by stratified flows.

3. More frequent inservice inspection of nozzle welds with high fatigue usage factors is needed. Some of the nozzle welds have a fatigue usage factor as high as 0.7 resulting from design transients alone.

4. Because stratified flows are likely to cause fatigue damage to the base metal in the horizontal sections of the surge and spray lines, inspection of the affected regions in the base metal needs to be included in the inservice inspection program. Current ASME Section XI inservice inspection guidelines do not require inspection of the base metal.

5. Acoustic emission techniques that reliably can detect the growth of fatigue cracks in both the welds and base metal of stainless steel piping should be developed. These techniques can then be used along with other nondestructive testing methods to characterize these cracks.

6. On–line fatigue monitoring should be used to measure coolant temperatures, pressures, and flow rates, and pipe wall temperatures. These data could be used to accurately calculate the accumulated low–cycle fatigue damage. Detailed and accurate records of the transients causing fatigue damage are not available. Some plants are already measuring these data.

7. A research program is needed to estimate the magnitudes and frequency content of the fluctuating loads imposed by thermal striping. These data are needed to estimate fatigue crack initiation times for the surge and spray lines.

8. Smaller temperature differences between the pressurizer and the hot leg coolant during heatup and cooldown can reduce fatigue damage to the surge line.

9. Plant operating procedures should specify full flow through the spray line and continuous spray during plant cooldowns. This practice will mitigate spray line fatigue damage caused by stratified flows and thermal shock. Some plants have already revised their operating procedures to this effect.

10. Properly sized bypass valves can provide full flow through the spray lines during normal operation and mitigate fatigue damage.

11. Replacing relatively short horizontal sections of spray piping with sloped sections can help prevent stratified flows.

Table 4.3. Summary of degradation processes for pressurizer surge and spray lines and nozzles

Rank	Degradation Sites	Stressors	Degradation Mechanisms	Potential Failure Modes	ISI Methods
1	Pressurizer Surge Line and Nozzle	Thermal transient stress loadings Stratified flow stress loadings, thermal striping	Low– and high–cycle thermal fatigue	Crack initiation and propagation leading to possible through–wall leak, pipe rupture	Piping and nozzle welds inspected volumetrically at each of the four 10–year intervals
		Thermal shock		Thermal sleeve cracking	
		Flow–induced mechanical vibration	Mechanical fatigue	Thermal sleeve cracking, crack initiation in nozzle	
		Temperature	Thermal embrittlement	Through–wall leakage	
2	Pressurizer Spray Line and Nozzle	Thermal transient stress loadings Stratified flow stress loadings (pipe only) thermal striping	Low– and high–cycle thermal fatigue	Crack initiation and propagation leading to possible through–wall leak Thermal sleeve cracking	Piping and nozzle welds inspected volumetrically at each of the four 10–year intervals
		Flow–induced mechanical vibration	Mechanical fatigue	Thermal sleeve cracking, crack initiation in nozzle	

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5. PRESSURIZED WATER REACTOR COOLANT SYSTEM CHARGING AND SAFETY INJECTION NOZZLES

E. A. Siegel and M. H. Bakr

In addition to the pressurizer surge and spray nozzles discussed in the previous chapter, other safety related nozzles, namely, the charging and the safety injection nozzles will be discussed in this chapter. These nozzles and their potential for fatigue-related degradation are common to the three pressurized water reactor (PWR) nuclear steam supply system designs and are subject to thermal-loading conditions that may significantly limit their fatigue life. The major system stressors are identified and the potential degradation mechanisms and probable failure modes are defined. The current inspection methods are described and an overall summary is provided with conclusions and recommendations.

5.1 Description

5.1.1 Charging Nozzles. The charging nozzles of the reactor coolant piping are located on the cold-leg loops and are part of the chemical and volume control system (CVCS). These nozzles are subject to a wide range of thermal-transient loadings during various modes of operation of the CVCS. Coolant flow (see Figure 5.1) from the cold leg of the reactor coolant system (RCS) passes through the tube side of the regenerative heat exchanger for an initial temperature reduction (inlet temperature equals cold-leg temperature). The cooled fluid is then reduced to the operating pressure of the letdown heat exchanger by the letdown control valves. Finally, the flow is reduced to the operating temperature and pressure of the purification system by the letdown heat exchanger and letdown backpressure valve. The flow passes through a purification filter, one of three ion exchangers, and a strainer and is then sprayed into the volume control tank (VCT).

The charging pumps take suction from the VCT and pump the coolant to the RCS. During normal operation, charging flow is equal to letdown flow plus

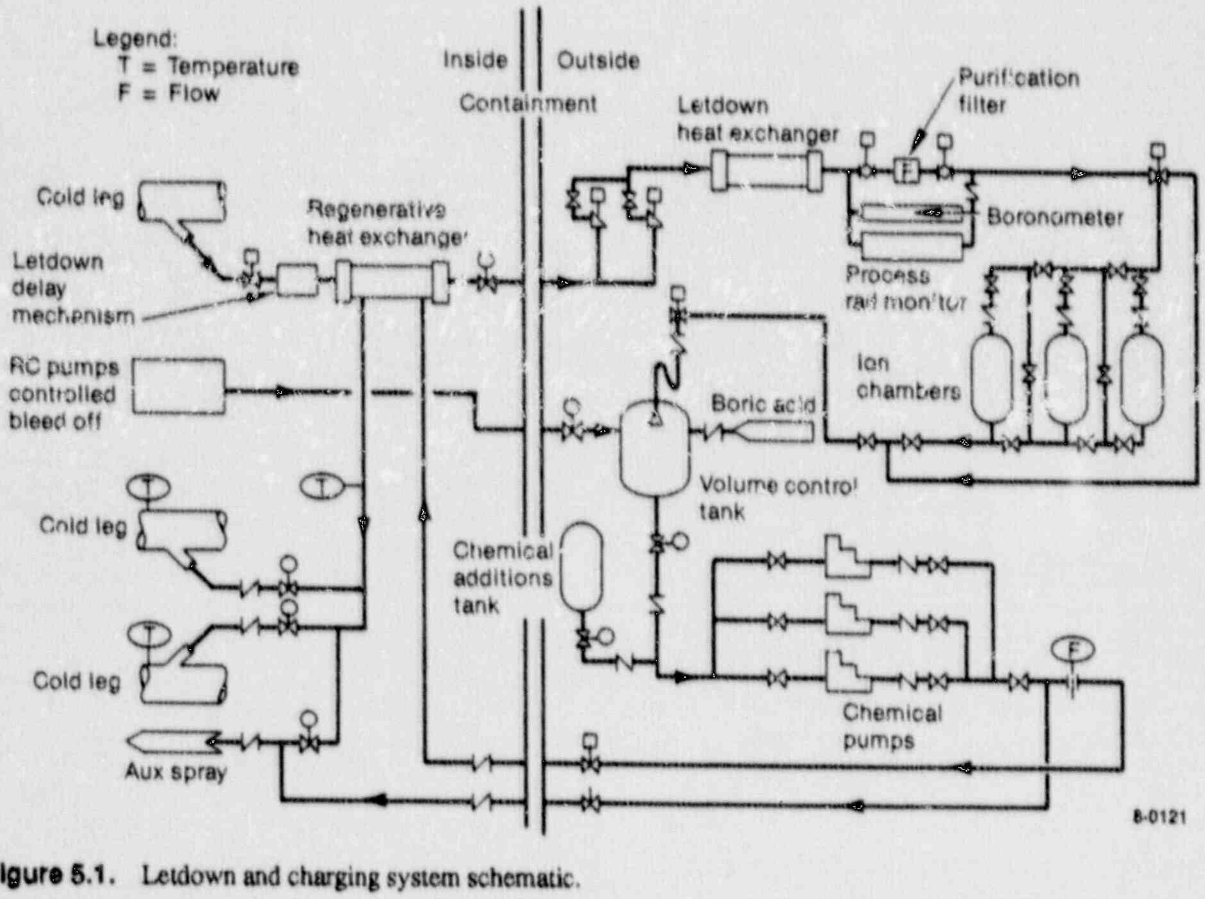

Figure 5.1. Letdown and charging system schematic.

reactor coolant pump bleedoff flow. The charging flow passes through the shell side of the regenerative heat exchanger for recovery of heat from the letdown flow before returning to the RCS cold leg via the charging nozzles. The charging fluid is always cooler than the reactor coolant in the cold leg. Babcock & Wilcox plants use one nozzle per cold leg for both makeup (charging) and safety injection. The Babcock & Wilcox design does not use a regenerative heat exchanger in the makeup coolant circuit.[1]

The charging inlet nozzles are 5-cm (2-in.) nozzles with thermal sleeves that protect the nozzles from thermal shocks. Combustion Engineering and Babcock & Wilcox plants use carbon-steel nozzles with a dissimilar metal weld to the stainless steel charging line. Westinghouse plants use stainless steel nozzles and connecting piping. A typical Combustion Engineering charging nozzle is shown in Figure 5.2.[a] Charging nozzles are within the reactor coolant pressure boundary and their structural integrity is therefore required for continued plant operation.

5.1.2 Safety Injection Nozzles. The safety injection system (SIS) is designed to provide core cooling in the unlikely event of a loss-of-coolant accident (LOCA). The cooling is intended to prevent excessive core heatup, significant cladding-water reactions, fuel melting, or significant alteration of the core geometry. The SIS is also designed to remove core energy for an extended period of time following a LOCA. The SIS fluid contains sufficient neutron absorber to maintain the core subcritical following a LOCA. In addition, the SIS functions to inject borated water into the RCS to prevent fuel damage and to increase the shutdown margin of the core in the unlikely event of a steam line rupture. The system is actuated automatically upon a low-pressure signal. Typical safety injection systems operate at about 9.0 MPa (1300 psi) and 50°C (120°F).

A typical Combustion Engineering safety injection system is shown in Figure 5.3. It consists of two high-pressure pumps, two low-pressure pumps, and four safety injection tanks. Some other PWR plants have dual-purpose pumps that are used for charging the RCS with coolant during normal operation and for injecting emergency core coolant at high pressure following an accident.[2] Automatic operation of the pumps is actuated by either a low pressurizer pressure signal or a high containment pressure signal. Flow is initiated from the SIS tanks when the cold-leg pressure drops below the pump shutoff head or the safety injection tank pressure. The safety injection nozzles include thermal sleeves. A typical Combustion Engineering safety injection nozzle is shown in Figure 5.4.

5.2 Stressors

5.2.1 Charging Nozzles. The principal source of stress affecting the fatigue aging of the charging nozzles is thermal-stress loadings. Typical charging nozzle design-basis thermal and pressure transients include plant heatup and cooldown, plant leak testing, CVCS isolation (caused by activities or events such as inventory balance, containment isolation, etc.), and other CVCS and plant operating functions.

ASME Code design calculations have demonstrated that these design-basis transients result in significant fatigue usage during a 40-year operating life.[a] However, the resulting fatigue usage factor is below the ASME Code allowable of 1.0. A typical design-basis maximum cumulative fatigue factor for the charging nozzle is 0.78.

Under normal steady-state operating conditions, the charging system continuously pumps makeup coolant from the CVCS at a temperature of approximately 205°C (400°F) through the charging inlet nozzle and into the cold-leg piping, which is normally at about

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a. Combustion Engineering engineering report, "Implementation of Charging Nozzle Evaluations for Generic Fatigue Damage Management," prepared for EPRI, May 1986.

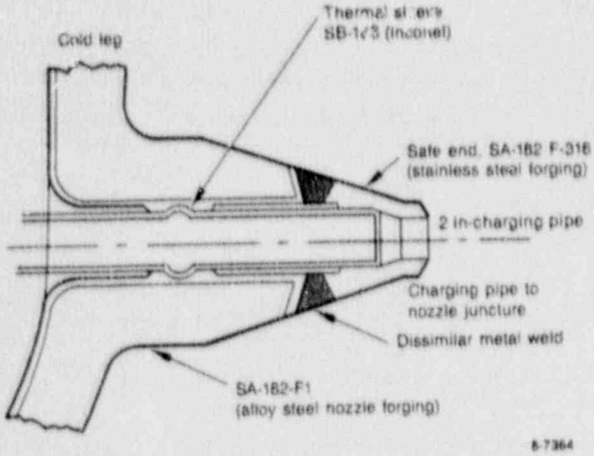


Figure 5.2. Typical Combustion Engineering charging nozzle (2-in. Schedule 160).

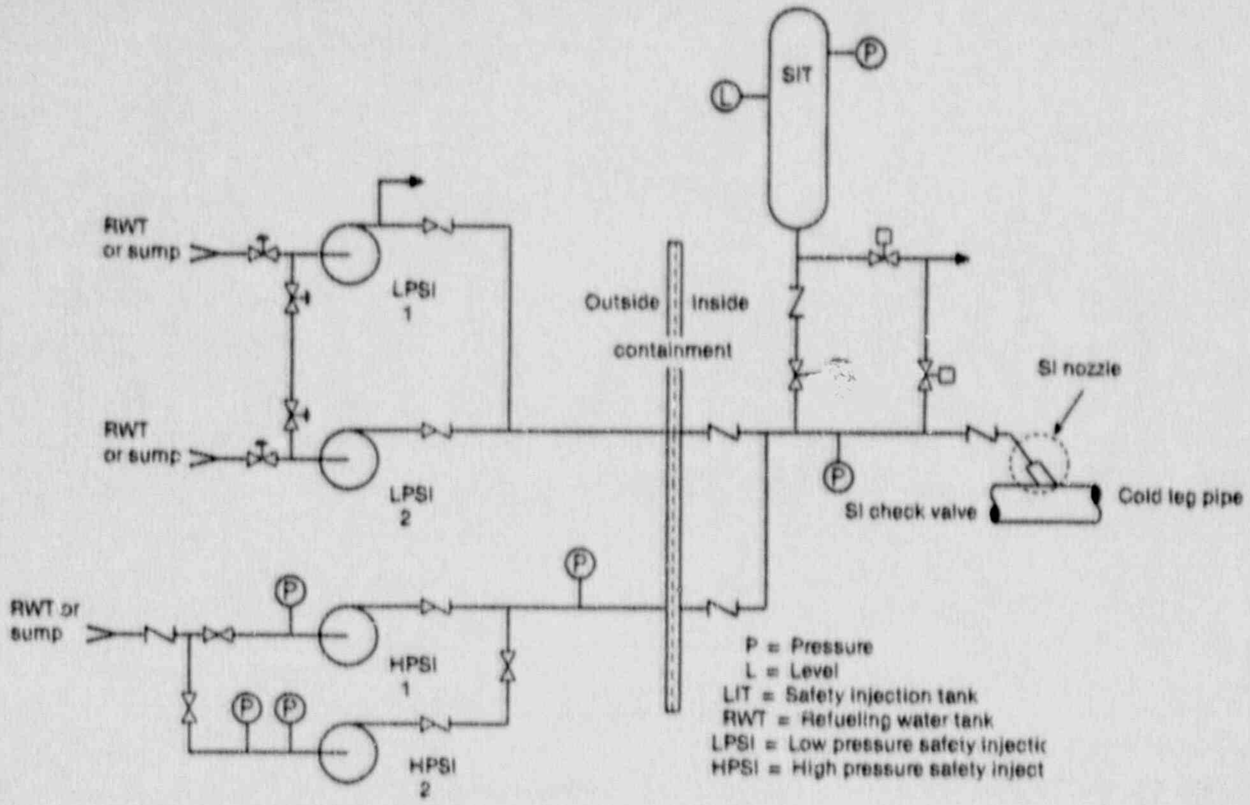


Figure 5.3. Typical Combustion Engineering safety injection system (simplified).

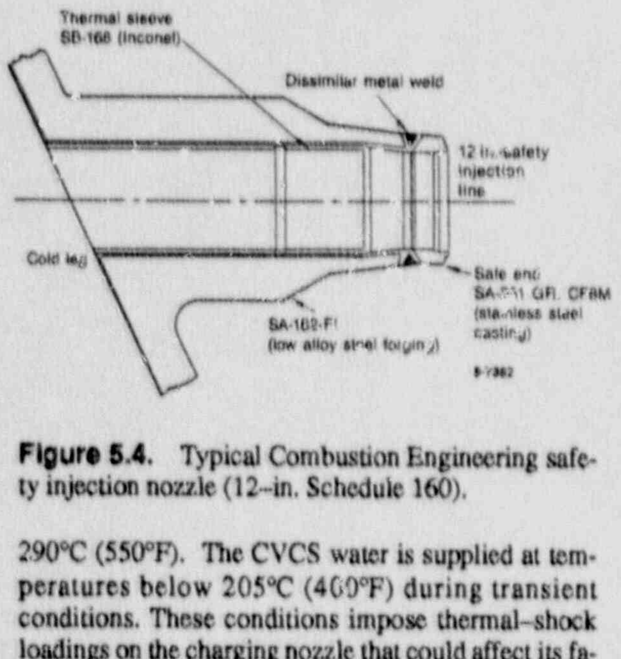


Figure 5.4. Typical Combustion Engineering safety injection nozzle (12-in. Schedule 160).

290°C (550°F). The CVCS water is supplied at temperatures below 205°C (400°F) during transient conditions. These conditions impose thermal-shock loadings on the charging nozzle that could affect its fatigue life. The juncture between the charging nozzle and the cold leg is usually protected by a thermal sleeve; therefore, the charging pipe-to-nozzle juncture becomes the most limiting location.

Among the most severe of the charging nozzle thermal transients is the loss-of-charging event followed by resumption of flow. This event may be caused by loss of letdown flow, loss of charging pumps, CVCS isolation for maintenance, or leak-check procedures. When the charging flow stops, the charging inlet nozzle, which is normally at about 205°C (400°F), is heated to the RCS cold-leg temperature of about 290°C (550°F). An idealized sketch of this heatup is shown in Figure 5.5. At the same time, the fluid in the charging line loses heat to the containment and gradually cools to about 50°C (120°F), as shown in Figure 5.6. When the charging flow is reinitiated, the charging nozzle is subjected to a thermal shock as the colder fluid in the charging line flows past the nozzle, followed by a rapid return of the fluid to the normal temperature of 205°C (400°F). This recovery event is shown in Figure 5.7. This type of severe cyclic loading will lead to rapidly increasing fatigue usage over time. Loss of charging is a design transient, but the frequency and severity of these transients will vary with plant operating procedures and could be more or less severe than assumed in the original design analysis. The temperature transients depicted in Figures 5.5 to 5.7 are predicted operating transients as opposed to design-basis curves.

Flow-induced vibration is another common stressor that affects components such as the thermal sleeves.

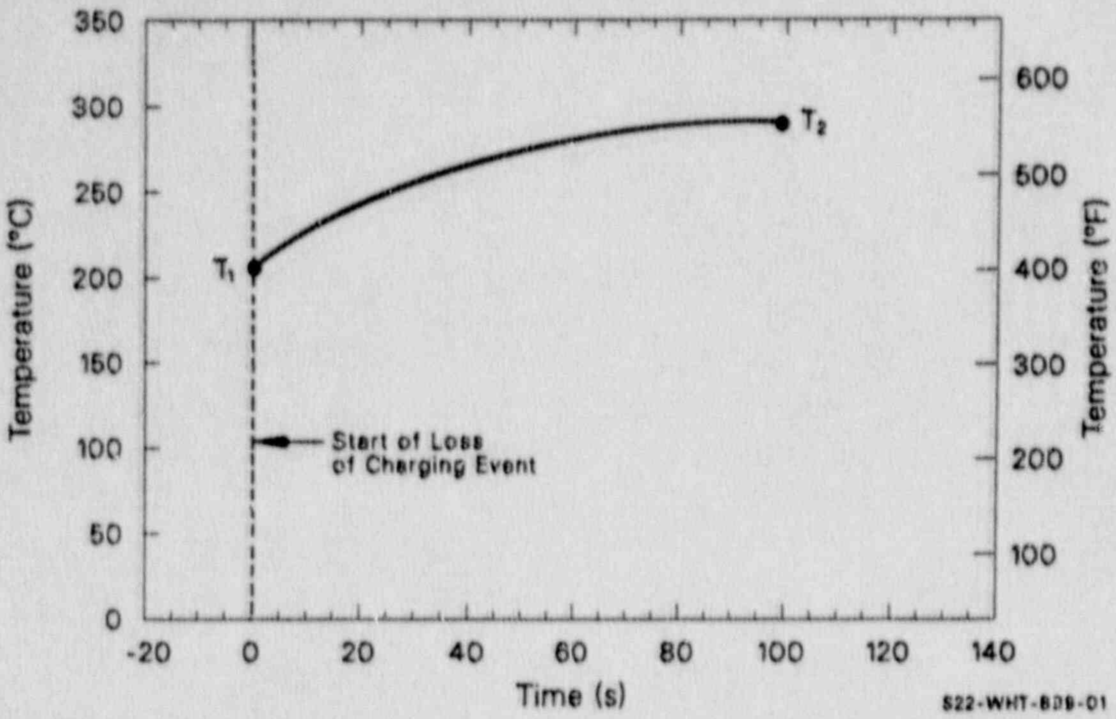


Figure 5.5. Charging nozzle thermal transient—loss-of-charging event.

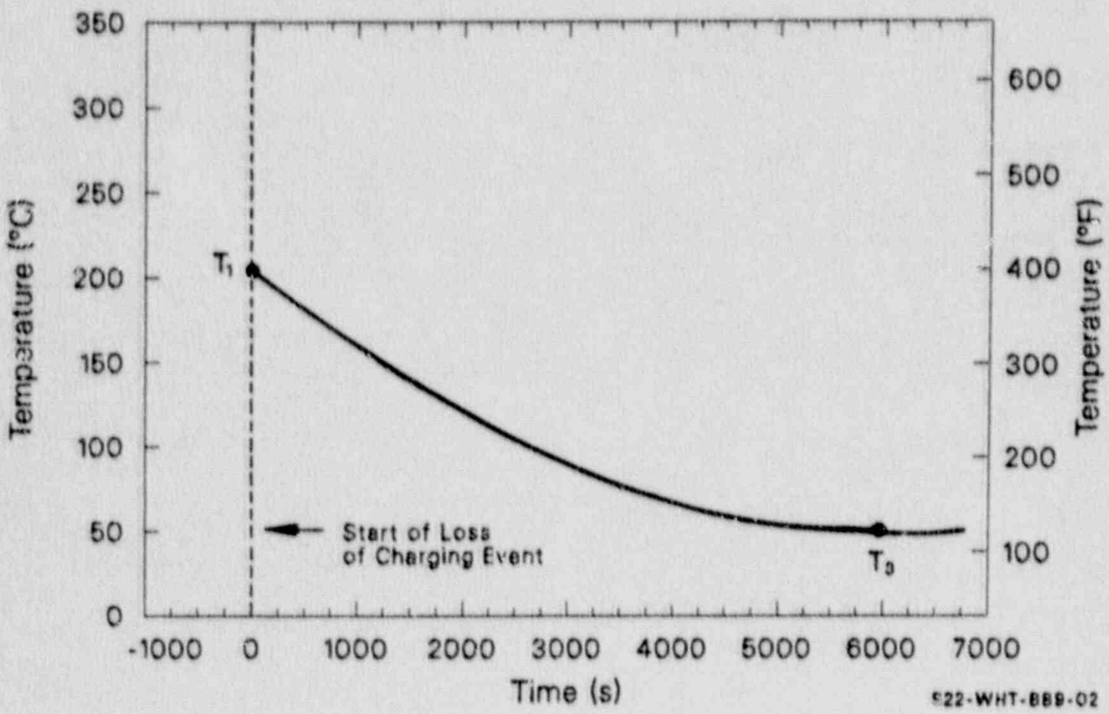


Figure 5.6. Charging line thermal transient—loss-of-charging event.

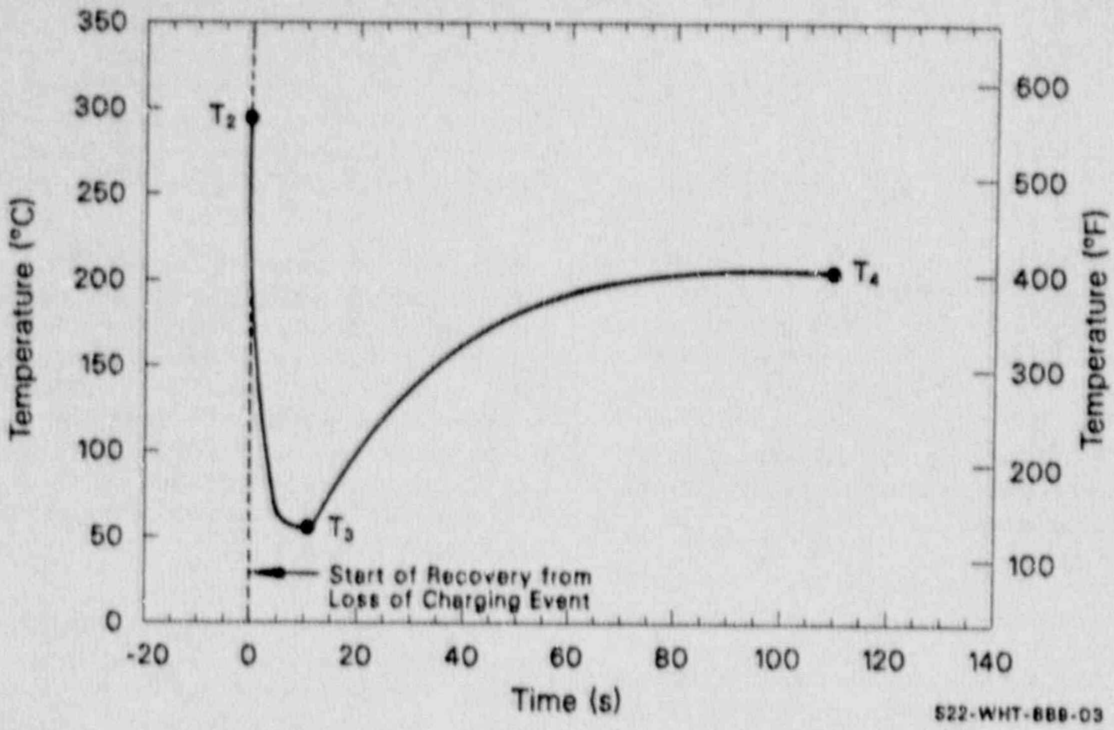


Figure 5.7. Charging nozzle thermal transient—recovery from loss-of-charging event.

The thermal sleeves are installed to protect the charging nozzles from thermal shock but are thin-walled tubes that cannot withstand high mechanical loads. This stressor could lead to fatigue failure of the thermal sleeve and could cause the thermal sleeve to break loose and move through the piping system. Loss of the thermal sleeves could ultimately lead to fatigue failure of the nozzle.

5.2.2 Safety Injection Nozzles. The safety injection nozzles are normally at the cold-leg temperatures and have no flow passing through them. However, the safety injection nozzles are subjected to the typical design-basis transients such as plant heatups and cooldowns, which can cause fatigue as well as other thermal loadings that in turn can significantly affect their fatigue aging. The most damaging of these loadings are induced by thermal-shock loads during a safety injection system actuation. During this transient, the safety injection system fluid undergoes a step temperature decrease from about 175°C (350°F) to a potential design-basis minimum of 5°C (40°F), followed by a step temperature increase from 5 to 175°C (40 to 350°F), both at a flow rate of up to 0.38 m^2/s (6000 gpm).[a]

a. Combustion Engineering engineering report, "Implementation of Piping Safety Injection Nozzle Evaluation for Generic Fatigue Damage Management," prepared for EPRI, September 1986.

The safety injection transients of concern also include the initiation and termination of safety injection flow in which the initial safety injection nozzle fluid temperature, equaling that of the cold leg, undergoes a step decrease to the safety injection tank temperature of about 50°C (120°F) when the flow is initiated. When the safety injection flow terminates, the nozzle fluid temperature rises back to approximately its initial cold-leg temperature, depending on the type and duration of the initiating event. These transients include safety injection system actuations during both periodic system tests and operation. This event is illustrated in Figure 5.8.

Localized fluid cooling may take place in the horizontal sections of the safety injection system piping upstream of the check valve because there is normally no flow in that system. A local area of stratified fluid may develop with warmer fluid in the upper portion of the piping and cooler fluid in the lower portion. This type of diametrical temperature variation will result in thermally induced bending stresses, which can also impact the fatigue life of the piping if the temperature differences are large enough. A thermal striping phenomenon is associated with the stratified-flow condition and can cause high-cycle fatigue damage to the piping inside surface in the vicinity of the hot- and cold-fluid interface. No quantitative data are available for the stratified-flow condition, and plant monitoring is

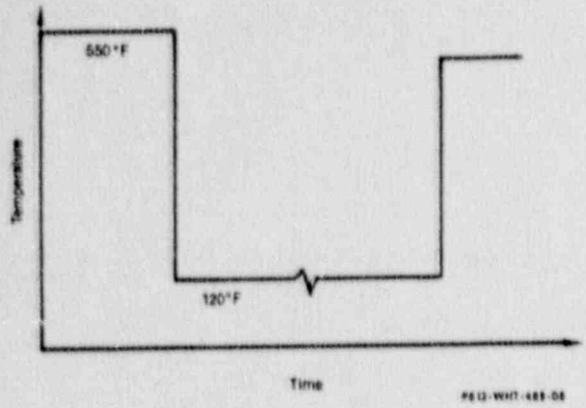


Figure 5.8. Predicted safety injection nozzle thermal transient caused by safety injection system initiation and termination.

required to determine actual temperature conditions. However, qualitative data[a] from testing by French utilities indicate that this flow stratification phenomenon may occur. Fatigue degradation caused by stratified flows was not considered in the original design analyses.

Flow-induced vibration is another common stressor that most affects thin-wall components, such as thermal sleeves, installed to protect the safety injection nozzle from thermal shock. This stressor can lead to fatigue failure of the weld between the thermal sleeve and the nozzle and to the thermal sleeve breaking loose and moving through the piping system.[3]

5.3 Degradation Sites and Mechanisms

5.3.1 Charging Nozzles. The charging nozzle degradation mechanisms resulting from the thermal-transient loading stressors described in Section 5.2.1 include both high-cycle and low-cycle thermal fatigue. The fatigue analysis procedure for Class 1 piping and vessel nozzles in nuclear plants is defined by Section III of the ASME Boiler and Pressure Vessel Code. Paragraph NB 3200 contains the Class 1 piping procedures for vessel nozzles. The Section III procedures are based on classical elastic stress-strain evaluations. The cumulative effects of nonuniform transient loadings are accounted for by Miner's rule. This approach accounts for fatigue damage accumulation by linearly summing fractional damage for a series of stress ranges. The cumulative damage fraction is limited to unity for the ASME Code fatigue evaluations.

a. T. Griesbach, private communication, EPRI, 1987.

Fatigue caused by flow-induced vibrations is another degradation mechanism for nozzles protected by thermal sleeves (such as the charging nozzles). Flow-induced vibrations can cause the thermal sleeve to break loose, which removes the protection against thermal fatigue and cracking of the nozzle.

There have been no known failures or identified cracks in the existing charging nozzles of Combustion Engineering-designed plants. Some cracking has been experienced in Babcock & Wilcox and Westinghouse charging and/or makeup lines.[1,4,5] In addition, a Westinghouse unit experienced a thermal sleeve failure in a 10-cm (4-in.) coolant makeup line. It was concluded that the failure of the sleeve and the resulting internal cracking of the primary coolant pipe were both caused by thermal fatigue.[6]

5.3.2 Safety Injection Nozzle. The safety injection nozzle degradation mechanisms resulting from the thermal-transient and thermal-shock loadings are also high- and low-cycle thermal fatigue.

There have been no known safety injection nozzle failures, but there have been reported failures of the thermal sleeves caused by flow-induced vibration, in addition to fatigue, caused by the thermal loadings. In some cases, the thermal sleeves were found to have broken loose. Additional discussion of this experience is provided in References 1 and 6. Again, note that several plants have experienced difficulties with thermal sleeves and that these sleeves provide significant protection to the nozzles.

A through-wall fatigue crack has recently been found in the heat-affected zone of the elbow weld in the 152-mm (6-in.) safety injection piping of a domestic PWR plant.[2,7] The crack was located downstream of the first check valve from the nozzle, or in other words, the crack was in that portion of the safety injection piping that constitutes the primary pressure boundary. The crack was on the inside surface of the weld extending approximately 120 degrees circumferentially around the underside of the pipe, and about 25 mm (1 in.) of this crack was through-wall. The crack developed slowly, and the resulting leak rate was 2.7 L/min (0.7 gpm). This failure resulted from high-cycle fatigue damage caused by thermal striping and flow stratification. Field measurements of the temperature distribution in the pipe wall indicate the presence of stratified flow and that the circumferential temperature difference near the weld was about 120°C (215°F). The stratified flow was caused by leakage of cold coolant through a nearby faulty valve. This particular portion of the safety injection pipe had also been identified as being susceptible to low-cycle fatigue failure.[8]

Valve leakage has also caused a through-wall fatigue crack in the base metal of an elbow in a safety injection pipe (between the first check valve and the safety injection nozzle) of a foreign PWR plant.[9] The crack was 89-mm (3.5-in.) long on the inside surface and 41-mm (1.6-in.) long on the outside surface. The crack developed rapidly, and the resulting leak rate was 23 L/min (6 gpm). A safety valve was installed downstream of the first check valve to mitigate the thermal fatigue loads caused by the leaking coolant. On-line monitoring of leakage from faulty or degraded valves is needed.

Other piping connected to the primary coolant is also susceptible to thermal fatigue damage because of valve leakage. For example, leakage from the first isolation valve on the 200-mm (8-in.), Type 316 stainless steel residual heat removal line has caused a through-wall, unisolatable crack.[10] The crack was located in a weld joint between an elbow and a horizontal pipe section between the hot leg and the valve. A detailed discussion of thermal stratification and striping and the associated fatigue damage to PWR surge, spray and feedwater lines is presented in Chapters 4 and 6.

5.4 Potential Failure Modes

The potential failure modes resulting from the thermal stressors discussed above are fatigue-induced crack initiation and propagation. Crack initiation alone does not generally result in through-wall leakage. Once a crack is initiated, there must be a loading or stressor that will cause the crack to propagate through the entire wall thickness. Loadings such as thermal stratification or piping loads from plant operation can result in crack propagation, whereas skin loadings such as thermal shock loads or thermal striping may cause only crack initiation.

There have been some failures of charging nozzles, thermal sleeves, and safety injection pipe caused by thermal fatigue and flow-induced vibrations. In some cases, the thermal sleeves were found to have broken loose.[3] The failure in the safety injection pipe was in the unisolatable portion of the pipe between the nozzle and the first check valve.[2] A potential failure mode for a flawed pipe or nozzle subjected to a seismic event is a double-ended break resulting in a small-break loss-of-coolant accident.

5.5 Inservice Inspection

Inservice inspection (ISI) of the charging and safety injection nozzles is required by Section XI of the ASME Code.[11] Four inspections spread 10-years apart are required during the 40-year operating life of a nuclear plant. All piping system welds where the calculated stress intensity exceeds 2.4 S_m (S_m is the maximum allowable primary membrane stress intensity, as defined in Section III of the ASME Code) or the calculated cumulative fatigue usage factor exceeds 0.4 must be included in the ISI program.[11] All of the nozzle-to-safe-end butt welds are also included in the ISI program. The ISI examinations for these locations consist of 100% surface and volumetric preservice examinations of all welds followed by a 100% surface and volumetric examination of a specified sample at each of the four 10-year intervals per ASME Section XI requirements.

The current inservice inspection methods recommended by the ASME Code are not capable of detecting thermal fatigue cracks.[12] For example, the use of ultrasonic testing with a 45-degree transducer and a gain of 6 dB, as required by the ASME Section XI, was not capable of detecting a through-wall thermal fatigue crack in the elbow weld of a high-pressure injection line. The crack was detected when the gain of the 45-degree transducer was increased by 8 dB and its use supplemented with a 60-degree shear wave transducer. In another instance, an instrumentation gain of 24 dB higher than that required by the ASME Code was needed to detect a through-wall crack.

Current inservice inspection requirements do not include the inspection of the base metal for fatigue cracks. However, regions of the base metal that are subjected to stratified flows and thermal striping are susceptible to fatigue cracks. For example, a through-wall crack has been found in the elbow base metal in a safety injection line. Through-wall cracks in the base metal have also been found in PWR and BWR feedwater lines subjected to stratified flows. Therefore, the USNRC requires the inspection of high-stress locations in both welds and base metals subject to thermal striping and stratified flows.

With respect to the thermal-sleeve issue, Westinghouse also recommended to its plant owners that the loose parts monitoring systems be operable and that nondestructive examinations be performed to assess thermal sleeve conditions of affected systems, as documented in Reference 4.

Both nozzles are included in a plant's ISI program, but the areas chosen for inspection may not be based on the potential occurrence of stratified flows or other severe thermal transients. The current industry practices in on-line monitoring and recording these thermal transients vary widely. Monitoring and transient recording systems are generally based on existing in-plant instrument availability and location. However, these systems are not adequate to monitor the transients caused by thermal striping and stratification. Section 4.5 discusses the currently used on-line monitoring method for detecting thermal stratification in some surge lines. Use of acoustic emission methods to detect thermal fatigue crack growth is also discussed in Section 4.5. Current on-line monitoring methods should be reviewed and evaluated for their applicability to charging and safety injection nozzles.

5.6 Summary, Conclusions, and Recommendations

A summary of the important potential degradation sites, stressors caused by operational transients, degradation mechanisms, and potential failure modes is presented in Table 5.1. The evaluation of the charging nozzles and safety-injection nozzles indicates that these nozzles are subject to fatigue damage caused by thermal-shocks, stratified flows, and flow-induced vibrations. Stratified flows were not fully considered in the original design analysis. Fatigue can limit the useful life of these components.

The conclusions and recommendations related to aging degradation of the PWR charging and safety injection nozzles are as follows:

1. The charging and safety injection lines subjected to stratified flows should be analyzed to determine whether a catastrophic rupture, rather than a leak-before-break, can take place. Leakage from faulty valves has resulted in thermal stratification and striping loads that have caused through-wall cracks in welds and base metal, and were not accounted for in the original design.

2. The high-stress locations in the base metal that are subjected to thermal striping and stratification need to be inspected. Current inservice inspection requirements do not include inspection of the base metal.

3. Current inservice inspection requirements are not adequate to detect thermal fatigue cracks, and need to be upgraded. Acoustic emission techniques may be used along with ultrasonic testing methods to characterize fatigue cracks.

4. On-line monitoring methods are needed to detect leakage from faulty or degraded valves. Such leakage has imposed thermal loads on the safety injection lines, causing through-wall cracks.

5. Appropriate methods are needed to monitor the charging and safety injection nozzle operational transients, so that the fatigue damage can be accurately estimated. The nozzles are subjected to stressors during plant operation that are considerably different and possibly more significant in magnitude and frequency than those considered in the original design.

Table 5.1. Summary of degradation processes for PWR RCS charging and safety injection nozzles

Rank	Degradation Site	Stressor	Degradation Mechanisms	Potential Failure Modes	ISI Methods
1	Charging nozzle	Thermal–transient stress loadings	High– and low–cycle thermal fatigue	Crack initiation and propagation leading to possible through wall leak	Piping and nozzle welds inspected volumetrically at each of the four 10–year intervals
		Thermal–shock stress loadings	High– and low–cycle thermal fatigue	Thermal sleeve cracking	—
		Flow–induced vibration	Mechanical fatigue	Thermal sleeve cracking, crack initiation in nozzle	—
2	Safety injection nozzle	Thermal–transient stress loadings	High– and low–cycle thermal fatigue	Crack initiation and propagation leading to possible through wall intervals	Piping and nozzle welds inspected volumetrically at each of the four 10–year intervals
		Thermal–shock stress loadings	High– and low–cycle thermal fatigue	Thermal sleeve cracking	—
		Stratified–flow stress loadings, thermal striping	High– and low–cycle thermal fatigue	Crack initiation and propagation leading to possible through–wall leak	—
		Flow–induced mechanical vibration	Mechanical fatigue	Thermal sleeve cracking, crack initiation in nozzle	—

5.7 REFERENCES

1. "Cracking in Piping of Makeup Coolant Lines at B&W Plants," USNRC IE Information Notice No. 82–09, March 31, 1982.

2. "Safety Injection Pipe Failure," USNRC IE Information Notice No. 88–01, January 27, 1988.

3. *Prioritization of Generic Safety Issues*, NUREG–0933, Issue 73, November 1983.

4. "Trojan Loose Thermal Sleeve Safety Evaluation," Trojan Nuclear Plant Docket 50–344, License NPF–1, July 1982.

5. "Loss of Thermal Sleeves in Reactor Coolant System Piping at Certain Westinghouse PWR Plants," USNRC IE Information Notice No. 82–30, July 26, 1982.

6. A. Flynn et al., "Thermal Sleeve Failure and Repairs—Indian Point #1 Nuclear Unit (285 MW)," *Nuclear Technology*, *25*, January 1975, pp. 13–31.

7. U.S. Nuclear Regulatory Commission, "Thermal Stresses in Piping Connected to Reactor Coolant Systems," NRC Bulletin No. 88–08, June 22, 1988.

8. Westinghouse Electric Corporation, *Application of the Leak–Before–Break Approach to Westinghouse PWR Piping*, EPRI NP–4971, Part 2, December 1986, pp. 1–2.

9. U.S. Nuclear Regulatory Commission, "Thermal Stresses in Piping Connected to Reactor Coolant Systems," NRC Bulletin No. 88–08, Supplement 1, June 24, 1988.

10. U.S. Nuclear Regulatory Commission, "Thermal Stresses in Piping Connected to Reactor Coolant Systems," NRC Bulletin No. 88–08, Supplement 3, April 11, 1989.

11. ASME Code Section XI, Table IWB 2500–1, Pressure Retaining Welds in Piping.

12. U.S. Nuclear Regulatory Commission, "Thermal Stresses in Piping Connected to Reactor Coolant Systems," NRC Bulletin No. 88–08, Supplement 2, August 4, 1988.

6. PRESSURIZED WATER REACTOR FEEDWATER PIPING AND NOZZLES

A. G. Ware, V. N. Shah, and E. A. Siegel

The aging degradation of the feedwater piping and nozzles in a pressurized water reactor (PWR) is discussed in this chapter because a loss of feedwater is an event that activates and challenges safety related systems and because several aging related feedwater piping failures have recently occurred. Failure of high-energy piping, such as the feedwater system piping, can also result in complex challenges to the plant operating staff because of potential interactions of the high-energy steam and water with other systems, such as the electrical distribution, fire protection, and security systems. Catastrophic failure of any high-energy piping also presents a safety problem for plant personnel.

The critical portion of the feedwater piping system from a degradation standpoint has been in the vicinity, and downstream, of the main feed pumps to the steam generator feedwater inlet nozzle. Any break in the feedwater piping system will disrupt the normal supply of cooling water to the steam generator. However, the size and location of the break is important in determining the sequence of events that will follow. Breaks outside the containment, in the vicinity of the main feed pumps, for example, will disrupt the feedwater flow, but the isolation check valves downstream of the rupture will prevent drainage of the steam generators through the break. The accident is countered by a rapid reactor trip and closure of the main steam isolation valves upon loss of feedwater flow. This ensures that sufficient water will remain in the steam generators to provide a heat sink for the reactor while the broken line is isolated and auxiliary feedwater is established for continued decay heat removal.

The consequences of a feedwater line break inside the containment depend upon the size of the break and the plant operating conditions at the time. The results of a small break are similar to the events described for the feedwater line break outside containment. However, a large feedwater line break (or main steam line break) will cause a rapid reactor coolant system cooldown (by excessive energy discharge through the steam generator fed by the broken line).[1] The steam generator inventory will be drained through the break, and the tubes will be uncovered. This accident is countered by a rapid trip of the reactor, and by the water inventory in the unaffected steam generators which should be sufficient to provide cooling until the broken line is isolated and the auxiliary feedwater system can be brought into operation for decay heat removal.

The feedwater line breaks that have occurred in operating PWRs are attributed to wall thinning caused by an erosion-corrosion mechanism, and to cracking caused by thermal fatigue from stratification. Feedwater lines have also been damaged by vibrations and water hammer events. Because feedwater piping is not subject to as rigorous an inservice inspection program as primary system piping, significant degradation can occur over a period of time without detection, thereby reducing the overall plant safety margin. If the piping is subsequently subjected to intense mechanical loadings, such as pressure pulses, a severe water hammer, or seismic events, the pipe wall may rupture.

6.1 Description

PWR main feedwater systems generally include parallel or multiple trains of feedwater piping (usually with a few large headers at selected points) to handle the large volumes of feedwater, for example, 6.8×10^6 kg/h (15×10^6 lb/h) for a typical 1100-MW unit. A multiple-train design also provides redundancy in the feedwater system that is beneficial for safety reasons. The main feedwater system receives water from the condensate system and supplies it at a much higher temperature and pressure to the steam generators. (The feedwater is pressurized by the condensate and feed pumps, and in some plants, feedwater booster pumps). The downstream piping terminates at the steam generator feedwater nozzle.

Figure 6.1 presents a simplified schematic of a typical Westinghouse 4-loop plant main feedwater system. This flow diagram begins downstream of the low-pressure feedwater heaters (not shown), at the booster pumps. The flow proceeds through the sets of intermediate feedwater heaters to the two main feedwater pumps, which discharge into a common header. The feedwater passes through three parallel high-pressure heaters into a common header, then branches into four lines to feed the steam generators through carbon steel feedwater nozzles. The main feedwater inlet nozzle is located above the tube bundle in steam generators without a preheater, whereas in steam generators with a preheater it is located near the tube sheet on the cold leg side of the steam generator. Each

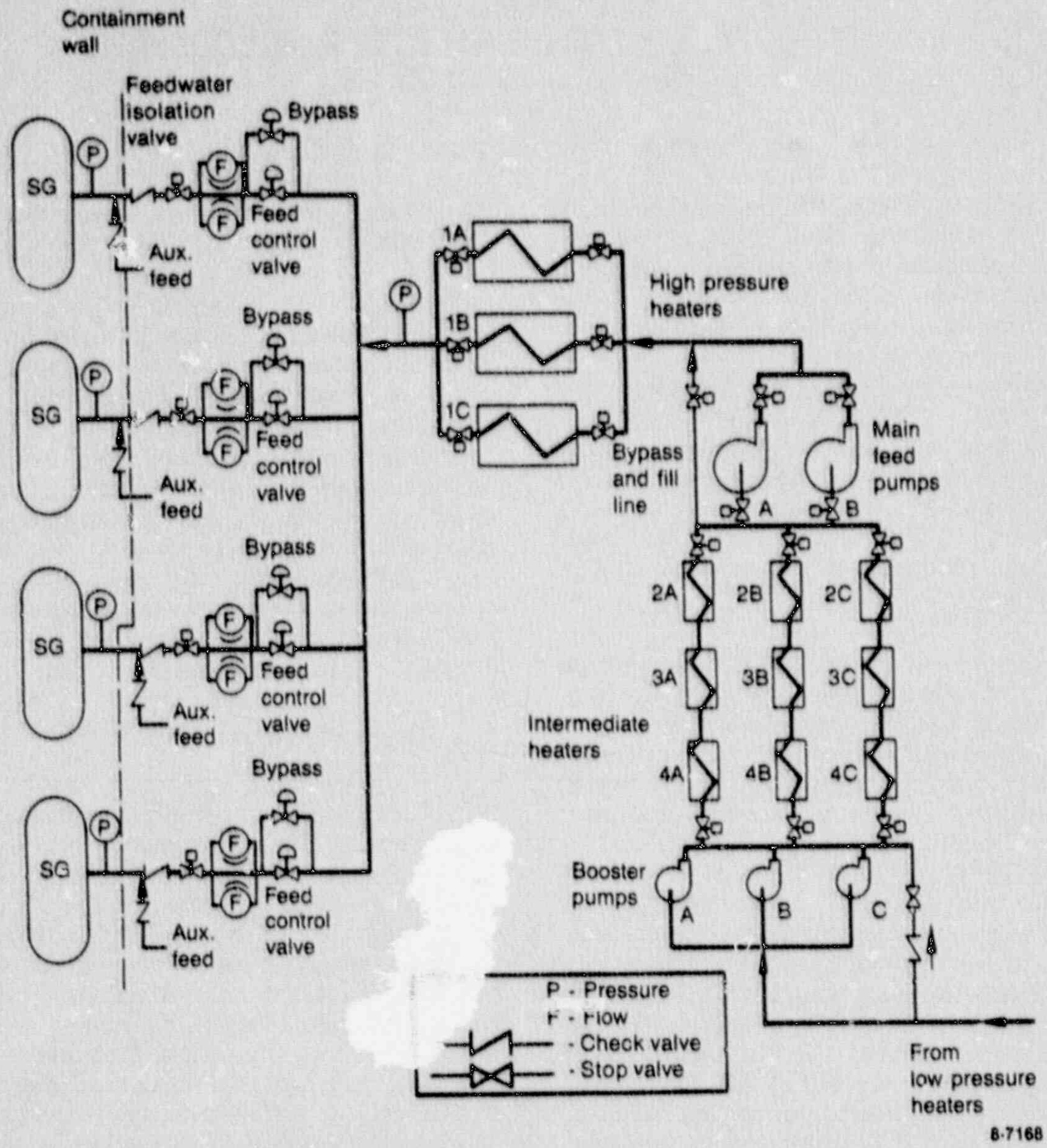


Figure 6.1. Schematic of 4–loop Westinghouse plant feedwater system.

of these feedwater lines has its own feed control valve, isolation valve, and check valve. Generally, an auxiliary feedwater system discharge line connects with each main feedwater line before it enters the steam generator. However, in steam generators equipped with a preheater, the auxiliary feedwater line connects directly to the steam generator above the tube bundle. The feedwater systems of Westinghouse 2–, 3–, and 4–loop plants and Combustion Engineering main feedwater systems have similar designs.

A simplified schematic of a Babcock & Wilcox main feedwater system is shown in Figure 6.2. There are two parallel trains of feedwater. In each, the flow passes through low–pressure heaters, the main feed pump, and high–pressure heaters, finally discharging into a common header. The flow then branches into separate lines feeding the two steam generators. Each line has a feedwater control valve, a main stop valve, and a check valve. The flow from the emergency feed pumps enters the steam generators through piping not connected to the main feedwater system.

Some PWR units have feedwater pressures much higher than the coolant saturation pressure, whereas other units have feedwater pressure at the suction of the feedwater pump close to the saturation pressure.[2] The operating pressure and temperature at the inlet to the feedwater pumps at 100% load, range from 2.0 to

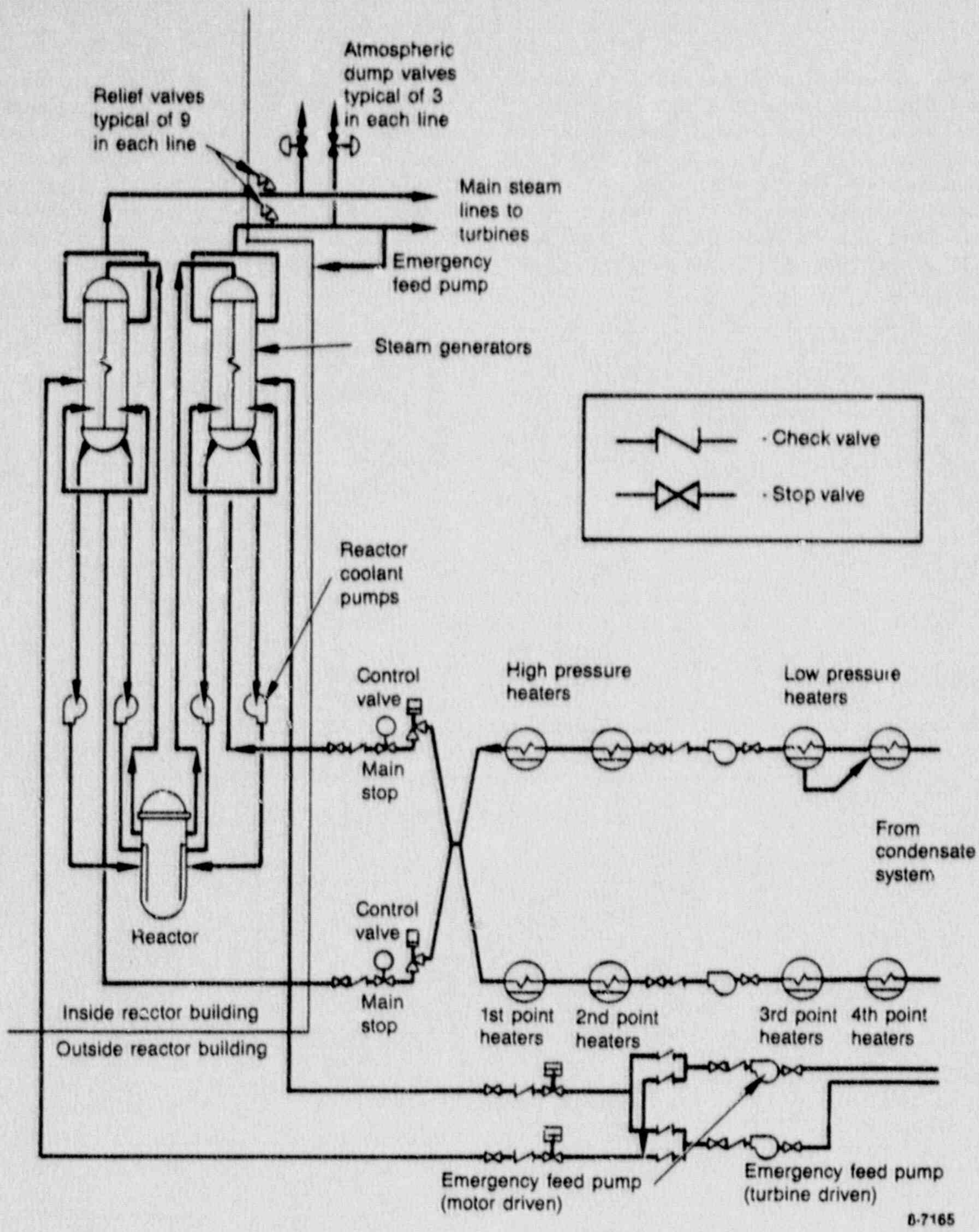


Figure 6.2. Schematic of Babcock & Wilcox plant feedwater system.

3.5 MPa (300 to 500 psia) and 160 to 204°C (320 to 400°F), respectively; at the outlet they range from 5.9 to 8.3 MPa (850 to 1200 psia) and 160 to 204°C (320 to 400°F), respectively. The typical values of feedwater pressure and temperature at the steam generator inlet range from 5.5 to 7.9 MPa (800 to 1150 psia) and 210 to 238°C (410 to 460°F). The typical bulk flow velocities at 100% load range from 3 to 7.6 m/s (10 to 25 ft/s). However, local flow velocities may be as high as 15 m/s (50 ft/s) or higher.

There is an auxiliary (or emergency) feedwater system that is used for backup upon loss of main feedwater, during startups and shutdowns, or when low-feed flow is required. Water is supplied from a condensate tank, typically at 50°C (120°F), or from service water when this supply is exhausted. Figure 6.3 shows an auxiliary feedwater system for a 2–loop Westinghouse plant. The feedwater flow originates at the condensate tank, passes through three auxiliary feedwater pumps (two motor driven and one steam driven), and through individual check and isolation valves for each of the three lines. Each auxiliary feedwater line connects to the main feedwater line between the containment penetration and the main feedwater valves. The feedwater then passes through a final check valve before entering the steam generator. Sometimes these check valves are inside the containment and in other plants they are located just outside the containment. Babcock & Wilcox plants have two main feedwater nozzles into each steam generator and a separate auxiliary feedwater nozzle (see Figure 6.2).[3]

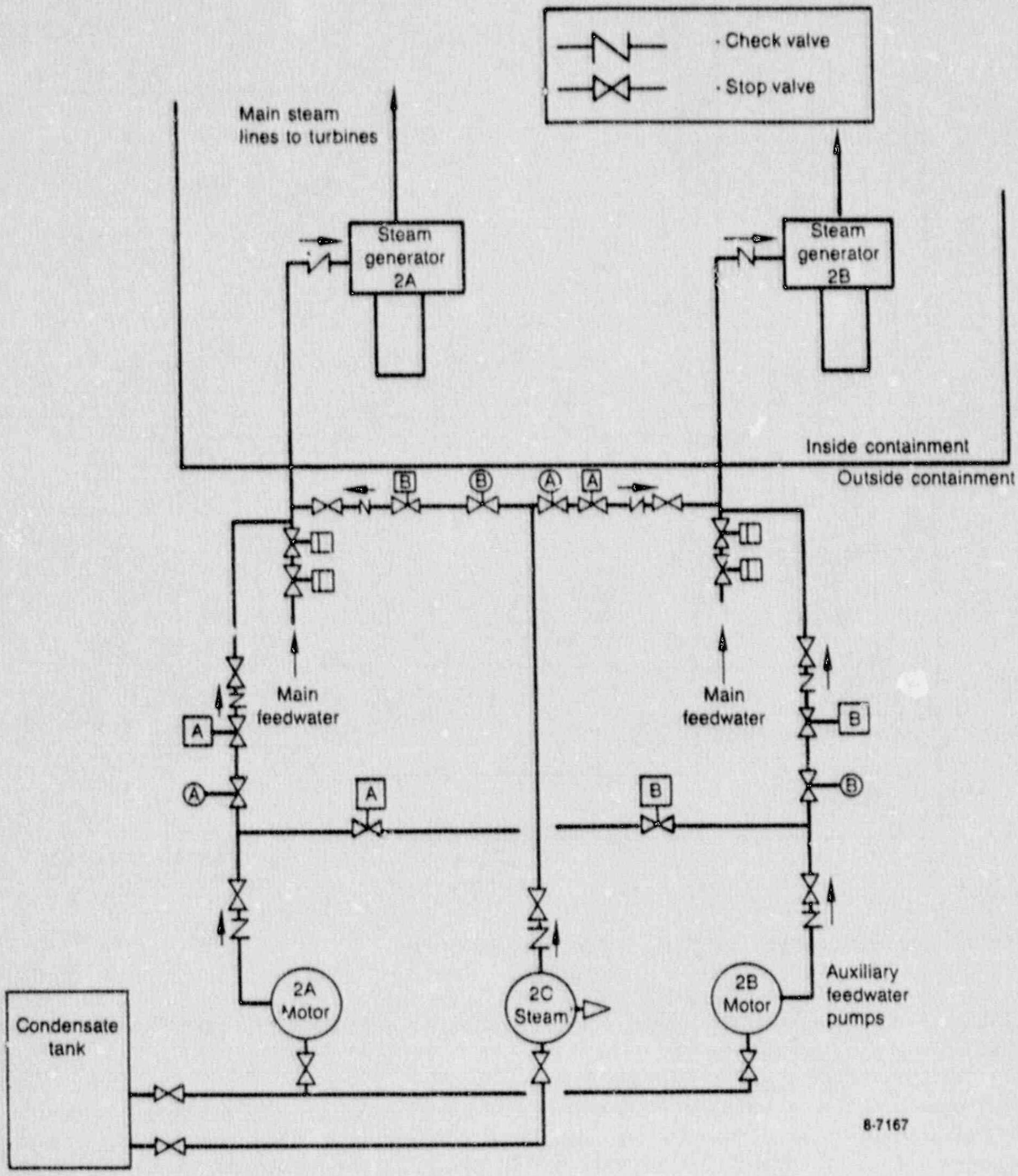


Figure 6.3. Schematic of 2–loop Westinghouse plant auxiliary feedwater system.

The feedwater piping is made of carbon steel, typically SA-106 Grade B for straight portions of pipes and A-234 Grade WPB for elbows. As an example of the piping design, the materials specifications and codes of construction for the St. Lucie 2 plant are listed in Table 6.1.[4] Chemical compositions of these materials and actual compositions of specimens taken from a ruptured feedwater line of the Surry 2 unit (see Figure 6.4 for location) are listed in Table 6.2.[5] All piping in the older plants was designed to ANSI B31.1 standards.[6] Fatigue analyses are not required by either ANSI B31.1 or the ASME Code[7] for Class 2 or 3 piping. Feedwater inlet nozzles to the steam generator are typically evaluated for fatigue as an ASME Code Class 1 component, though this is not required by the ASME Code.

6.2 Stressors

The important stressors affecting the PWR feedwater piping systems include the flow and coolant conditions that promote erosion–corrosion of the inside surfaces: flow stratifications, thermal shocks, water hammer events, and flow- and/or rotating-machinery-induced vibrations.

The average bulk flow velocity in the feedwater piping is in the range of 3 to 7.6 m/s (10 to 25 ft/s). However, the piping layout may introduce turbulence in the feedwater system, and the local flow velocities in the elbows can be two to three times higher than the bulk flow velocities. Higher local flow velocities tend to increase erosion–corrosion rates in carbon steel piping. Feedwater temperatures are typically in the range of 160 to 240°C (320 to 460°F) and play an important role in determining the erosion–corrosion rates. The pH level of the feedwater and the oxygen content also influence the erosion–corrosion rates. The solubility of iron oxide [Fe_3O_4 (magnetite)] highly depends on pH. PWR pH levels are generally maintained in the range of 8.8 to 9.6. The erosion–corrosion rates of carbon steel are significantly reduced when the pH is above 9.2 and increase with pH when the pH is below 9.2.[8] PWRs usually maintain relatively low oxygen contents in the feedwater, for example, about 4 ppb at most plants, to minimize steam generator tube degradation.[9,10] However, higher oxygen contents (above 20 ppb) promote the formation of hematite (Fe_2O_3), a stronger and less soluble oxide, and therefore less erosion–corrosion damage. Impurities in the feedwater (often resulting from condenser in-leakage) can also contribute to the degradation of the feedwater piping at high-velocity locations. The feedwater at the suction of the pumps may also be two-phase if it is near saturation, and the formation and collapse of vapor bubbles in the liquid near the piping walls may cause cavitation damage within or upstream of the feedwater pumps.

In addition to the typical design basis thermal transient cycles (similar to those listed in Tables 3.3 and 4.1 of Chapters 3 and 4, respectively), two thermal transients have been identified that could potentially affect the feedwater nozzle fatigue aging process. These additional transients are stratified flow and thermal shock.

Table 6.1. Typical materials and fabrication codes for feedwater piping[4]

Piping	Material	Code
Feedwater piping to outermost containment isolation valve	ASME SA-106, Grade B	ASME Section III,[a] Class 2
Balance of piping	ASME SA-155, Grade KC-65 ASME SA-106, Grade B	ANSI B31.1[b]
Elbows	ASTM A-234, Grade WPB	
Auxiliary feedwater discharge piping	ASME SA-106, Grade B	ASME Section III,[a] Class 2 or Class 3 as applicable

a. Reference 7.

b. Reference 6.

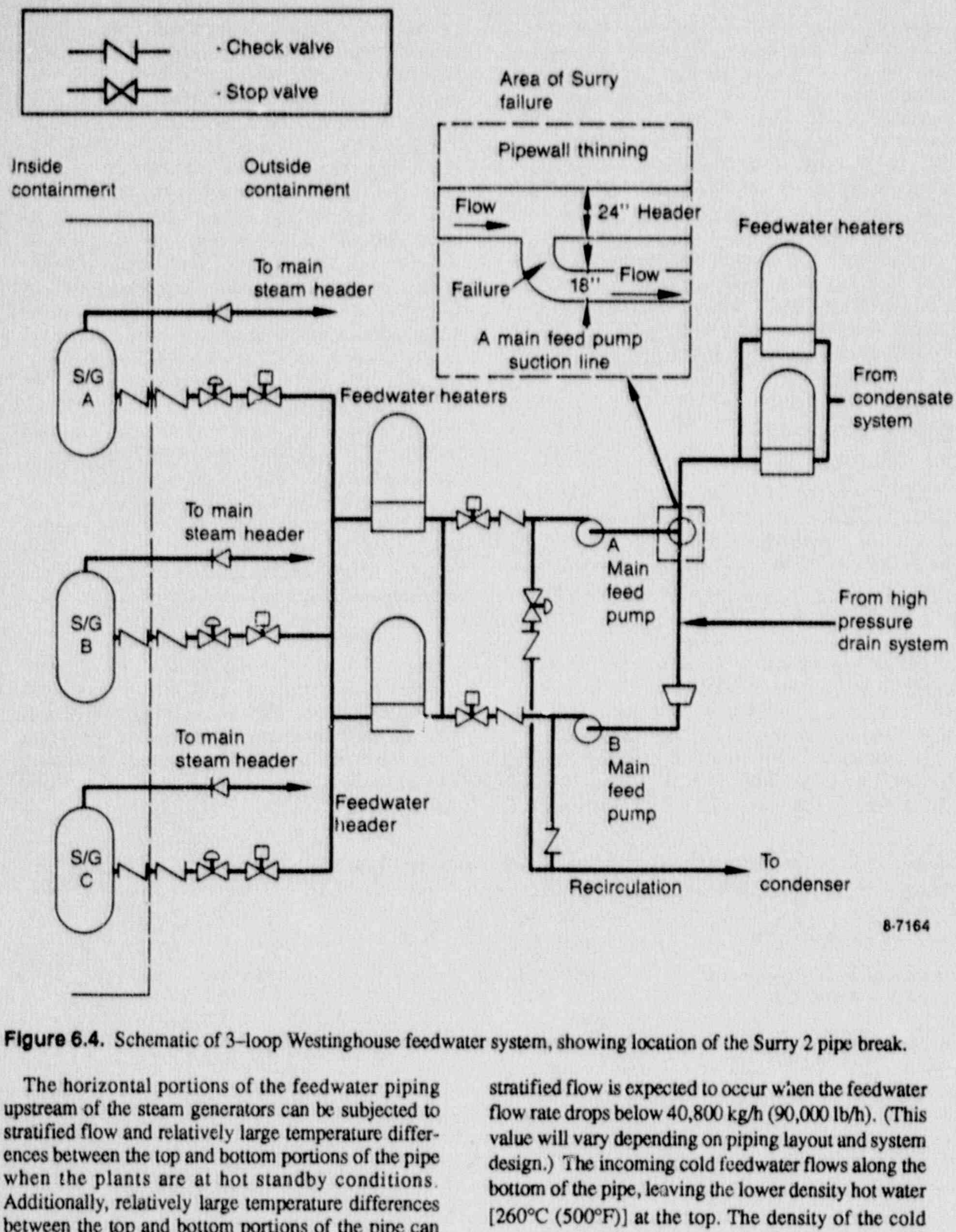


Figure 6.4. Schematic of 3-loop Westinghouse feedwater system, showing location of the Surry 2 pipe break.

The horizontal portions of the feedwater piping upstream of the steam generators can be subjected to stratified flow and relatively large temperature differences between the top and bottom portions of the pipe when the plants are at hot standby conditions. Additionally, relatively large temperature differences between the top and bottom portions of the pipe can occur during plant startup and shutdown when the feedwater heaters are not in use, the feedwater is relatively cold [~40°C (~100°F)], and flow rates are low. Based on Combustion Engineering test data, stratified flow is expected to occur when the feedwater flow rate drops below 40,800 kg/h (90,000 lb/h). (This value will vary depending on piping layout and system design.) The incoming cold feedwater flows along the bottom of the pipe, leaving the lower density hot water [260°C (500°F)] at the top. The density of the cold feedwater [38°C (100°F)] is roughly about 993 kg/m^3 (62 lb/ft^3), whereas the density of the hot water [260°C (500°F)] in the steam generator is approximately 785 kg/m^3 (49 lb/ft^3).[11]

Table 6.2. Typical chemical compositions of SA-106 Grade B and A-234 Grade WPB.[5]

SA-106 Grade B Composition Weight Percent	Chemical Requirement[a]	Actual Specimen[b]
Carbon (max)	0.30	0.20
Manganese	0.29–1.06	0.83
Phosphorous (max)	0.048	<0.005
Sulfur (max)	0.058	0.023
Silicon (min)	0.10	0.10
Chromium	NR	0.07
Nickel	NR	0.02
Molybdenum	NR	0.01

A-234 Grade WPB Composition Weight Percent	Chemical Requirement[a]	Actual Specimen[b]
Carbon (max)	0.30	0.23
Manganese	0.29–1.06	0.69
Phosphorous (max)	0.05	<0.005
Sulfur (max)	0.058	0.013
Silicon (min)	0.10	0.22
Chromium	NR	0.07
Nickel	NR	0.01
Molybdenum	NR	0.01

a. NR = no requirement.

b. Material from ruptured elbow in Surry 2 feedwater piping.

Figure 6.5 shows an example of the flow stratification that can occur in a PWR feedwater nozzle when the steam generator water level is above the top of the feed ring.[11] Figure 6.6 shows a typical Combustion Engineering feedwater nozzle. The temperature difference between the top and bottom of the pipe (metal temperature) can approach 200°C (400°F),[12,13] and the corresponding stress distribution in the piping is comparable with a bimetallic strip when it is heated. Therefore, the top-to-bottom temperature differences in the horizontal feedwater lines cause low-cycle fatigue damage in the pipe wall as the interface level is increased from the bottom of the pipe to the top and returned to the bottom again. In addition, the mixing layer at the interface of the hot and cold layers of the feedwater is wavy, with about a 0.1- to 1.0-Hz frequency content. Therefore, the piping material in the vicinity of the mixing layer is subjected to high-cycle fatigue.[13] A similar condition can occur when the total feedwater flow decreases below the threshold where stratified flow develops and the steam generator water level drops below the top of the feed ring, causing the upper part of the nozzle to fill with hot steam instead of hot water.

Another predicted flow-initiation transient is illustrated in Figure 6.7. This situation can occur during a no-feedwater-flow to full-feedwater-flow condition with the steam generator water level initially below the top of the feed ring. The initial temperature of the feedwater nozzle equals the steam generator saturation steam temperature. Upon the flow initiation event, the fluid in the nozzle undergoes a step decrease from the steam temperature [typically 295°C (560°F)] to the feedwater temperature [50 to 238°C (120 to 460°F)], and the nozzle experiences a thermal shock. A similar transient is illustrated in Figure 6.8 and can occur during a full-feedwater-flow to no-feedwater-flow condition when the steam generator level is below the top of the feed ring and the feedwater flow decreases to nearly zero. This transient is practically the reverse of

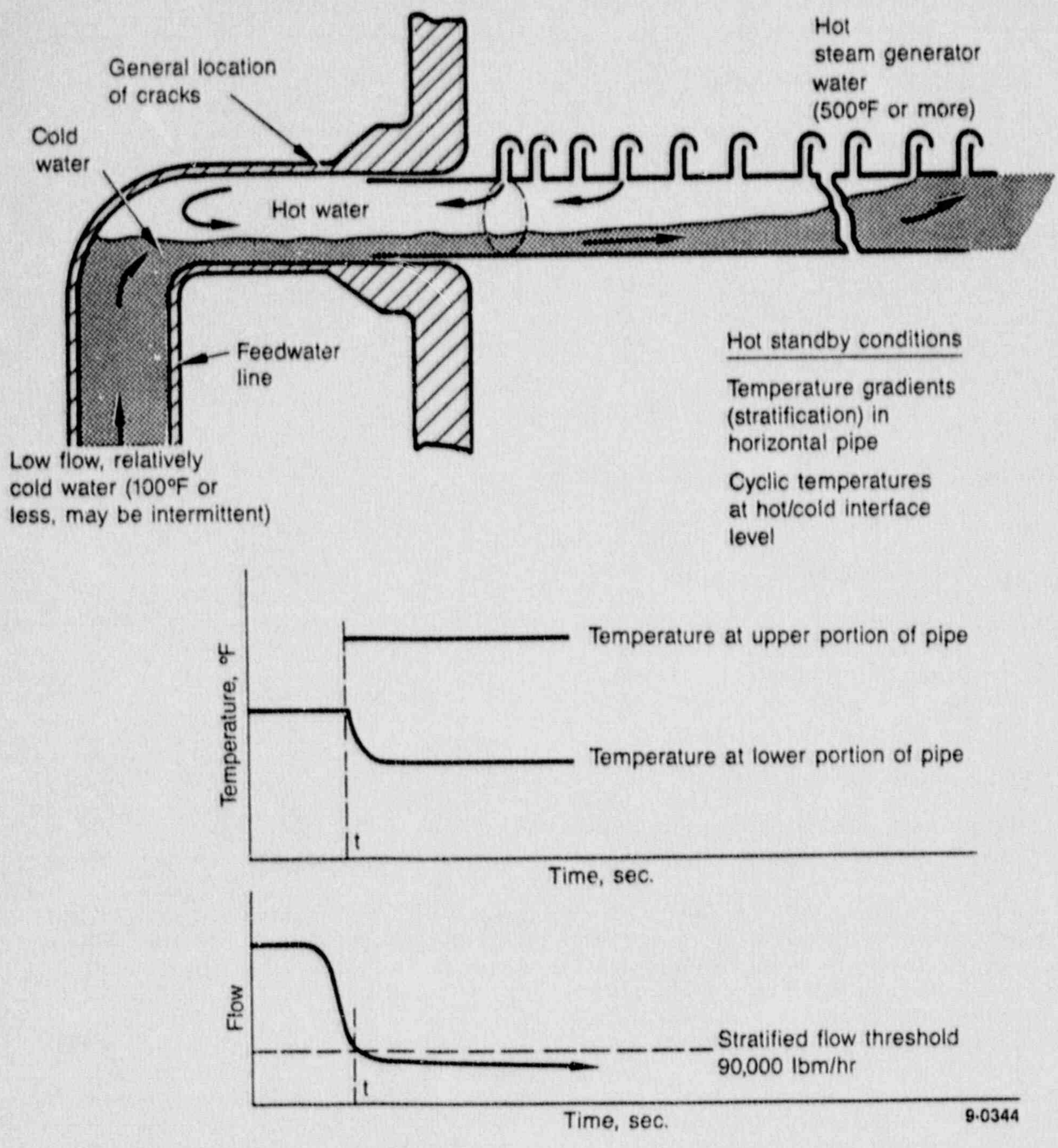


Figure 6.5. Flow stratification in PWR feedwater nozzle.

the previous transient, and the nozzle undergoes a step increase in temperature from feedwater temperature to a temperature near the steam temperature.

The introduction of relatively cold [50°C (120°F)] auxiliary feedwater during startup and shutdown will impose a thermal shock on the feedwater piping, which is normally at 230°C (450°F). Thermal shocks introduce skin stresses on the piping inside surface; therefore, the associated fatigue damage is likely to result in crack initiation, but not necessarily crack growth.

Water hammer is a multicycle load induced by transient pressure pulsations in the feedwater fluid. It can result from a fast valve closure, such as a check valve closure caused by flow reversal, or intermittent

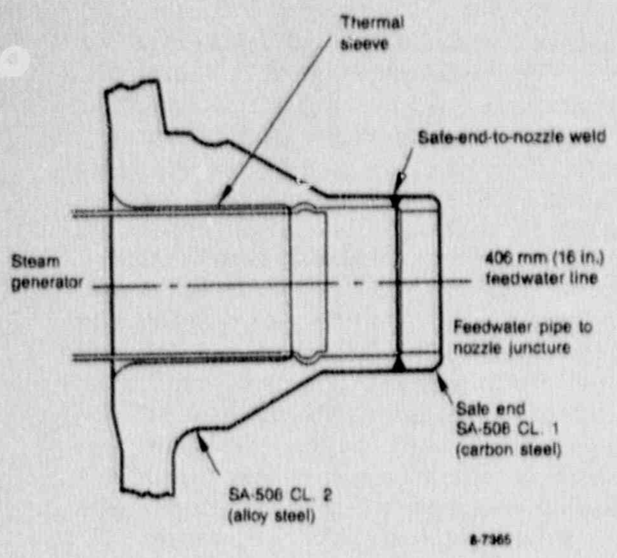


Figure 6.6. Typical Combustion Engineering feedwater nozzle.

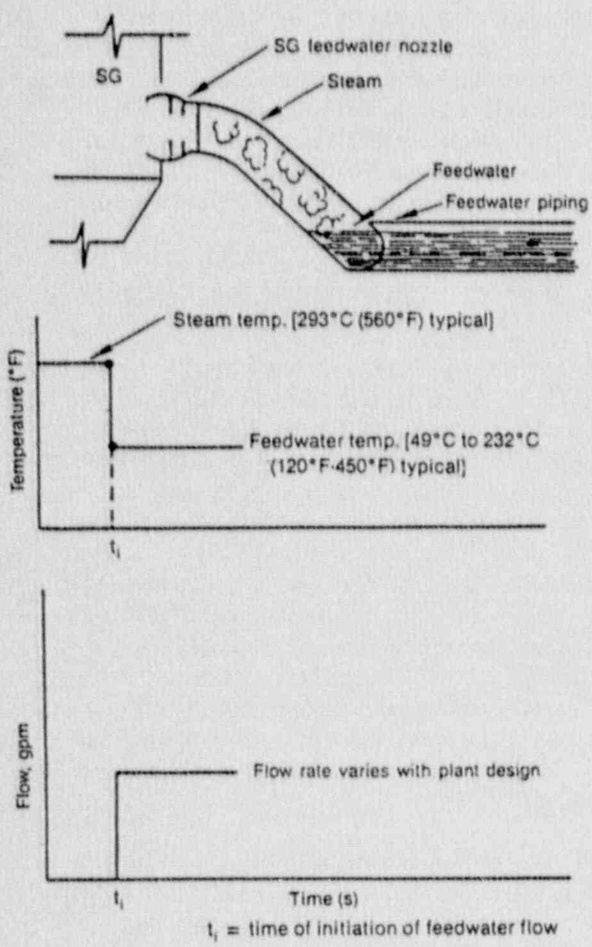


Figure 6.7. Steam generator feedwater nozzle transient (no flow to full pipe flow).

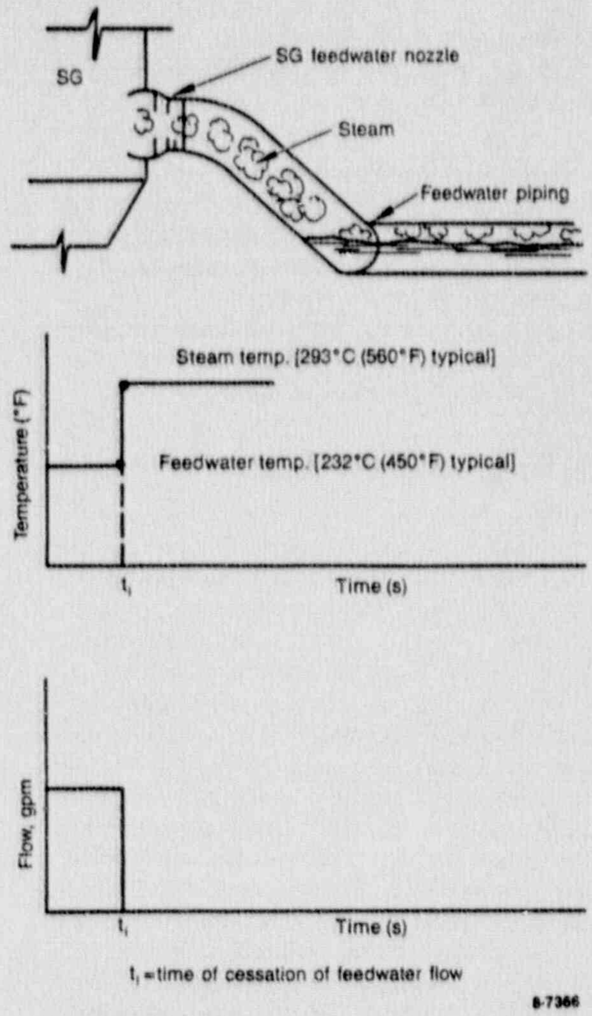


Figure 6.8. Steam generator feedwater nozzle transient (full pipe flow to no flow).

operation of feedwater regulation valves. Water slugging is a single load induced by accelerating a slug of water through the piping. Pump startup can initiate this event in the feedwater lines, especially if the discharge lines have been voided. If the slug impacts a stationary column of water, a pressure transient will be generated in the water. If a travelling water slug impacts an elbow, it will introduce dynamic stresses in the piping. Water hammers and water slugging are usually short-duration events, typically occurring in less than 1 s, but with dramatic effects. Large, unbalanced forces can be exerted on the piping and cause low-cycle fatigue damage, as well as severe damage to the pipe supports and restraints. In severe cases, piping may also be damaged.[14] Water hammer events can also produce mechanical overloadings on the feedwater nozzle.[15,16] These mechanical overloads can lead to the failure of a nozzle already degraded by thermal-fatigue accumulation. While all plants have taken steps to minimize the occurrence of water hammers by installing J tubes in the steam generator feed ring or by other modifications, water hammer events still may occur.

Flow-induced vibration is another common stressor that affects components such as thermal sleeves installed to protect the feedwater nozzle from thermal shock. This stressor can lead to the fatigue failure of the thermal sleeve and the possibility of the thermal sleeve breaking loose and moving through the piping system. Flow- and pump-induced vibrations cause high-cycle fatigue damage to the piping systems.

6.3 Degradation Sites

Erosion-corrosion and thermal fatigue are responsible for most of the aging degradation that has occurred in PWR feedwater systems. Piping layouts are responsible for most flow discontinuities causing turbulence in the feedwater, and the resulting high flow velocities play an important role in erosion-corrosion damage. Figure 6.4 shows such a location where erosion-corrosion caused a catastrophic rupture. Unfavorable piping layouts include elbows without turning vanes, sites with a small radius of change in direction, and branch connections of 90 degrees. Sites where the distances between a change in direction and other discontinuities are small do not allow the turbulence to dissipate, and remain susceptible to relatively high rates of erosion-corrosion. Areas where repairs have been made with weld metal on the inside surface are particularly susceptible to high rates of erosion-corrosion at the leading and trailing edges of the weld. (Such discontinuities may be present at the inside surface of the feed ring in the steam generator where new J tubes are welded in place of original J tubes previously damaged by erosion-corrosion.)[a] Because the piping layouts differ from plant to plant, specific vulnerable locations need to be evaluated for each individual plant.

Sections of carbon steel piping have been replaced in several power plants by stainless steel or chrome-molybdenum alloy sections. However, the carbon steel near the dissimilar metal welds may be susceptible to galvanic corrosion, and erosion-corrosion, if the weld edges introduce any geometric discontinuities on the inside surface that cause turbulence.

Stratified flow causes low- and high-cycle fatigue damage to horizontal sections of the feedwater piping. The weld joining the steam-generator feedwater nozzle and the steam generator is usually protected by a thermal sleeve; therefore, most failures occur in the piping or at the feedwater pipe-to-nozzle weld upstream of the thermal sleeve. Fatigue failures and through-wall cracks in the vicinity of the steam-generator feedwater nozzles and thermal sleeves have been reported at Westinghouse, Combustion Engineering, and Babcock & Wilcox-designed plants.[17,18,19] Furthermore, weld cracks in the auxiliary feedwater nozzle thermal sleeves have been found in some Babcock & Wilcox plants, including those plants characterized as originally having an external auxiliary feedwater header. The affected plants continue to operate with periodic inspection programs.[20]

A number of fatigue cracks have also been found in small pipelines at most operating plants. They are located predominantly in socket welds in the 3/4- to 2-in.-diameter pipe range. The cracks were generally located near pumps[11] and are attributed to equipment- and flow-induced vibration. While most of these failures have been associated with the chemical- and volume-control system, 16% of the failures in PWRs have been associated with the feedwater system.[15] Drain lines and instrumentation lines (pressure taps) are examples of branch lines susceptible to this type of degradation.

6.4 Degradation Mechanisms

The main aging degradation mechanisms affecting the PWR feedwater lines are erosion-corrosion and low- and high-cycle thermal fatigue. Carbon steel piping carrying single-phase fluid was not expected to be damaged by erosion-corrosion; therefore, little attention has been paid to this mechanism in the past. However, the catastrophic failure of the feedwater piping at the Surry 2 plant has generated interest in this aging mechanism. The erosion-corrosion of carbon steel piping carrying single-phase fluid is discussed in Section 6.4.1. Stratified flow is the main stressor causing thermal fatigue in feedwater piping and is discussed in Section 6.4.2. Corrosion fatigue, cavitation damage, and galvanic corrosion are discussed later in this section.

6.4.1 Erosion-Corrosion. Erosion-corrosion is a flow-assisted corrosion mechanism that affects carbon steel piping carrying single-phase, subcooled feedwater. The damage caused by erosion-corrosion is higher than damage attributed to erosion or corrosion alone. Feedwater piping corrodes during normal operation, forming a thin layer of iron oxide [mostly

a. J. Hopenfield, personal communication, USNRC, January 1988.

magnetite (Fe_3O_4)] on the inside surface. This layer protects the underlying piping material from the corrosive environment, and in the absence of erosion, limits the corrosion rate. However, if stressors causing erosion are present, the layer of iron oxide will dissolve and the uncorroded metal surface will again be exposed to the corrosive environment and piping corrosion will continue. Thus, the continuous process of oxide growth and dissolution leads to thinning of the pipe wall and ultimately to a catastrophic failure when the pipe is under pressure. Figure 6.9 presents a simple model describing the phenomena occurring during erosion–corrosion.[21]

The factors affecting the erosion–corrosion rate include the following:

- Piping configuration
- Feedwater temperature
- Bulk–flow velocity
- Turbulence
- pH level
- Impurities
- Oxygen content
- Piping material.

The piping configuration (elbows, tees, and 90–degree branch connections) creates turbulence that increases the local velocity of the feedwater flow, and is a significant factor affecting the erosion–corrosion rate. Experiments have shown that local–flow velocities in elbows can be two to three times the bulk–flow velocities.[8,10] Geometric discontinuities on the piping inside surface (leading and trailing edges of welds) also create turbulence in the feedwater flow. The erosion–corrosion rate increases with increasing flow velocities, though the effect is more pronounced in two–phase flow conditions.[22] Therefore, inside surfaces should be as smooth as possible and relatively large radius bends should be used.

A. Iron hydorxides are generated: $Fe + 2H_2O \longrightarrow Fe(OH)_2 + H_2$
B. Magnetite is formed according to the Schikorr reaction:
$3Fe(OH)_2 \longrightarrow Fe_3O_4 + H_2 + 2H_2O$
C. A fraction of the hydroxides formed in step B and hydrogen generated in steps A and B diffuse along pores in the oxide
D. Magnetite can dissolve in the pore
E. Magnetite dissolves at the oxide-water interface
F. Water flow removes the dissolved species by a convection mass transfer mechanism
G. Water and solid particles break off porous oxide layer by a mechanical erosion mechanism

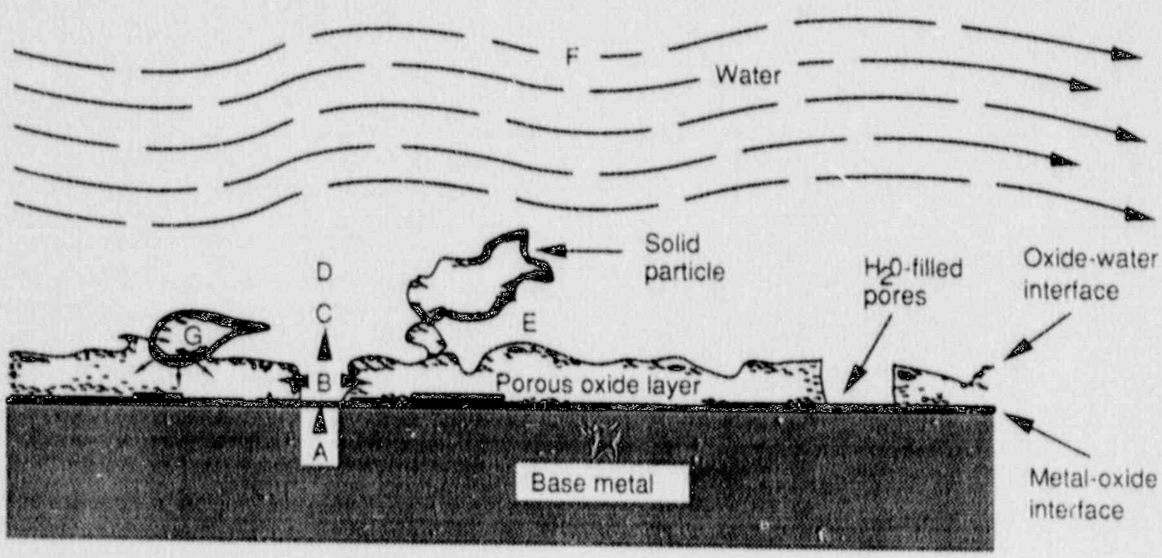


Figure 6.9. Phenomena occurring during erosion–corrosion.

The flow-assisted erosion-corrosion rates of carbon steel piping are highly temperature and pH dependent. Erosion-corrosion rates are greatest at about 120 to 170°C (250 to 340°F) and decrease rapidly at temperatures above and below this value, as shown in Figure 6.10 (but can still be significant at temperatures well above or below this value if other factors are unfavorable).[23] However, other studies have identified different temperature ranges for the peak erosion-corrosion rates. Erosion-corrosion data for single-phase flow conditions obtained at the Central Electric Research Laboratories (CERL) show that the rate of erosion-corrosion reaches a maximum at about 130 to 135°C (270 to 280°F). The reasons for the apparent discrepancy in temperature dependence may be attributed to the variations in the trace levels of chromium present in the material tested.[23] Figure 6.11 shows the variation of the rate of erosion-corrosion of the CERL samples with temperature.[24] The flow rate was 227 to 983 kg/h (1 to 5 gpm) through the 8.33-mm-(0.33-in.-) diameter tube, with flow velocities of 1.2 to 5.8 m/s (4 to 19 fps) and the pH level was in the range of 8.5 to 9.2.

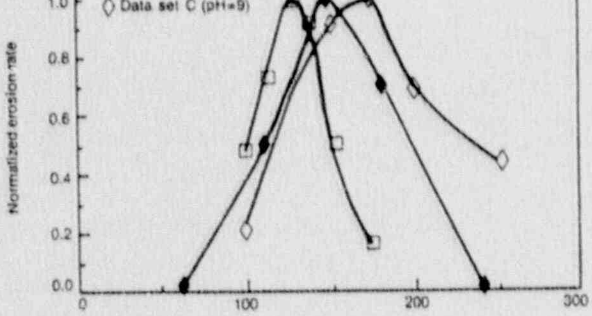


Figure 6.10. Effect of temperature on normalized erosion-corrosion rates.[23]

Erosion-corrosion rates decrease by an order of magnitude over the pH range 8.5 to 9.5, which is typical for feedwater systems.[23] Figure 6.12 shows the solubility of magnetite (Fe_3O_4) in deoxygenated water, which directly correlates with the erosion-corrosion rate.[25] The rate is greatest when the pH levels are lower. Feedwater system materials and use of ammonia or morpholine determine the optimum pH level.[24] Feedwater systems with copper alloy materials should maintain a pH level in the range of 8.8 to 9.2 to prevent excessive copper pickup. Systems with all steel materials can maintain a pH level in the range of 9.3 to 9.6. Ammonia is generally used for pH control in the PWR feedwater system, and the corresponding optimum pH level is in the range of 9.3 to 9.6. If morpholine is used instead of ammonia, the pH level is maintained at 9.1 to 9.2. At the time of the feedwater pipe failure at Surry 2, the system operating temperature was 193°C (380°F) and pH levels were reportedly maintained between 8.8 and 9.2.

Poor control of secondary water chemistry and condenser in-leakage will increase the conductivity of the feedwater and, thus, contribute to corrosion of feedwater piping. It will also contribute to erosion-corrosion, especially at locations of high flow velocities.

Erosion-corrosion rates are inversely affected by the amount of dissolved oxygen in the feedwater, and too low an oxygen level is harmful to carbon steel piping. Normally, the oxygen level is kept low (about 4 ppb) in PWR secondary systems to minimize the degradation of the steam generator tubes. However, such a low oxygen level does not promote the formation of a highly protective oxide film on the carbon steel piping. Tests with neutral water at 100°C (212°F) have shown that the erosion-corrosion rates of carbon steel are high when the water contains less than 20 ppb oxygen, but decrease rapidly with the addition of more oxygen.[26] The oxygen level in PWR feedwater systems can be increased by the injection of oxygen gas or hydrogen peroxide. In fact, oxygen feed has significantly reduced the erosion-corrosion rates in tests conducted in PWR environments in the United Kingdom.[24] Oxygen injection leads to the formation of a stronger, less soluble iron oxide (hematite), capable of reducing the erosion-corrosion rate by a factor of 3 to 10.[8] Because an increase in oxygen content may increase the fatigue-crack-growth rate in carbon steel piping, as well as degrade steam generator tubes, caution is warranted prior to implementing any changes in the secondary water chemistry.

The erosion-corrosion rate is highest in carbon steel piping with very low levels of alloying elements. The presence of chromium, copper, and molybdenum even at small percentage levels, reduces the erosion-corrosion rate significantly.[8,24] Test results show that the erosion-corrosion rates are reduced by a factor of 100 with 2% Cr, 1% Mo, and 1% Cu as alloying elements. Tests performed under PWR conditions show that 12% Cr steels have excellent resistance; 2-1/4 Cr-1 Mo is still better than steel containing copper; and steel with <1% chromium has less resistance to erosion-corrosion.[24] Table 6.2 shows that the material of the elbow that ruptured at the Surry 2 plant had low amounts of these elements, particularly chromium (0.07%) and molybdenum (0.01%).[5]

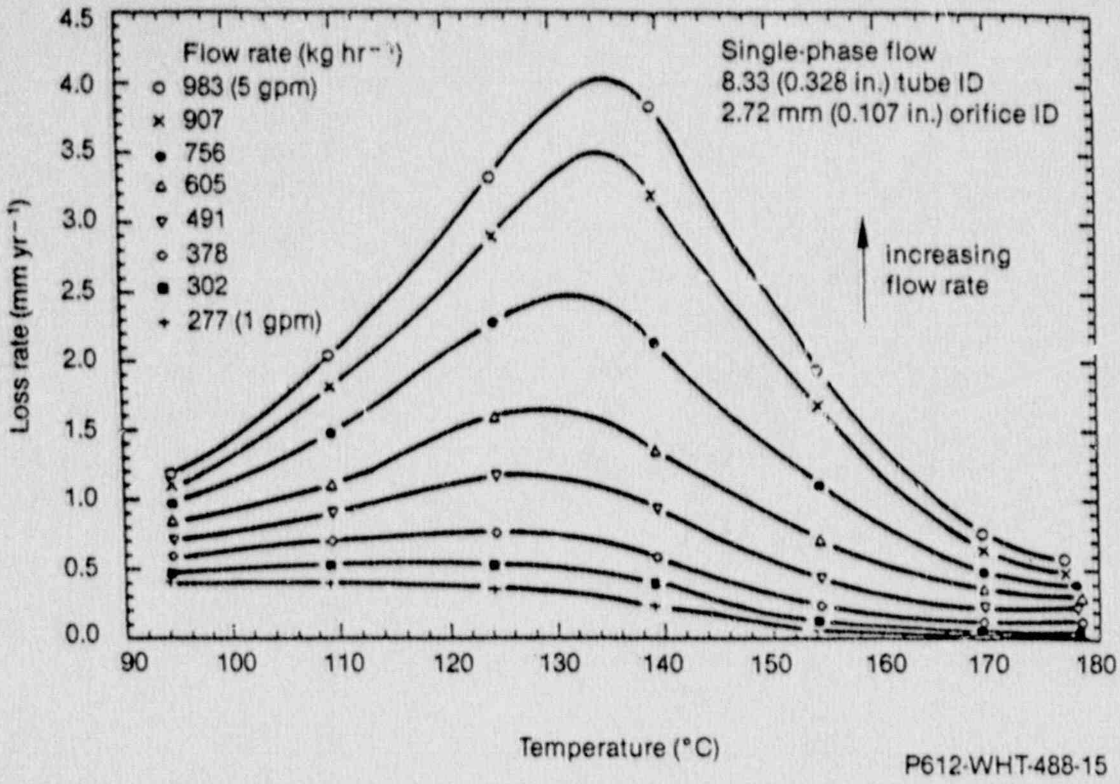


Figure 6.11. Flow/Temperature dependence of single-phase, erosion-corrosion rates.[24]

Erosion-corrosion damage is highly localized and can vary significantly over short distances. For instance, only 6 mm away from a through-wall gouge, the inside surface of the pipe may be virtually unaffected.[27] This aspect of erosion-corrosion damage makes it difficult to develop appropriate inspection programs. Inservice inspection programs are further discussed in Section 6.6.

A stainless steel coating has been used to mitigate erosion-corrosion damage in wet steam piping in foreign nuclear power plants.[28] A flame-spraying technique is used to apply three layers of a Type 304 stainless steel coating. The top layer of the coating provides the desired resistance to erosion-corrosion. The bottom layer provides a sufficient mechanical bond to the carbon steel surface. The intermediate layer provides a bond between the top and bottom layers. The thickness of the coating is about 0.5 mm (0.020 in.). Field application of this coating requires a minimum diameter of about 600 mm (24 in.), whereas shop application requires a minimum pipe diameter of about 100 mm (4 in.). The use of a stainless steel coating on feedwater piping to mitigate erosion-corrosion damage should be evaluated as a cost-effective alternative to replacing damaged piping with low-alloy or stainless steel piping.

6.4.2 Low-Cycle Fatigue. Low-cycle fatigue is caused by plant heatups and cooldowns, flow stratification, water hammer events, and thermal shocks. Fatigue associated with the thermal expansions and contractions caused by the plant heatup and cooldown cycles is relatively straightforward to analyze, but the fatigue caused by stratified-flow conditions is somewhat more complicated. Stratified flows consist of a hot and cold fluid separated into two layers because of their density difference.[29] A thin mixing layer is developed between the hot and cold fluid layers as shown in Figure 6.13(a). The height of the mixing layer depends primarily on the mass flow and density ratio. The mixing layer is wavy and introduces high-cycle stresses in the adjacent piping inside-wall surface which penetrate only a short distance into the wall. This high-cycle fatigue phenomenon is also known as thermal striping and is discussed further in Section 6.4.3. The stratified flow also introduces through-wall axial and circumferential bending stresses whose magnitudes are determined by the top-to-bottom temperature difference ($T_H - T_C$), and height and thickness of the mixing layer.

Figure 6.13(b) shows the theoretical distribution of the axial bending stresses caused by a stratified flow when the mixing layer is at 60 degrees from vertical. This distribution assumes a zero thickness for the

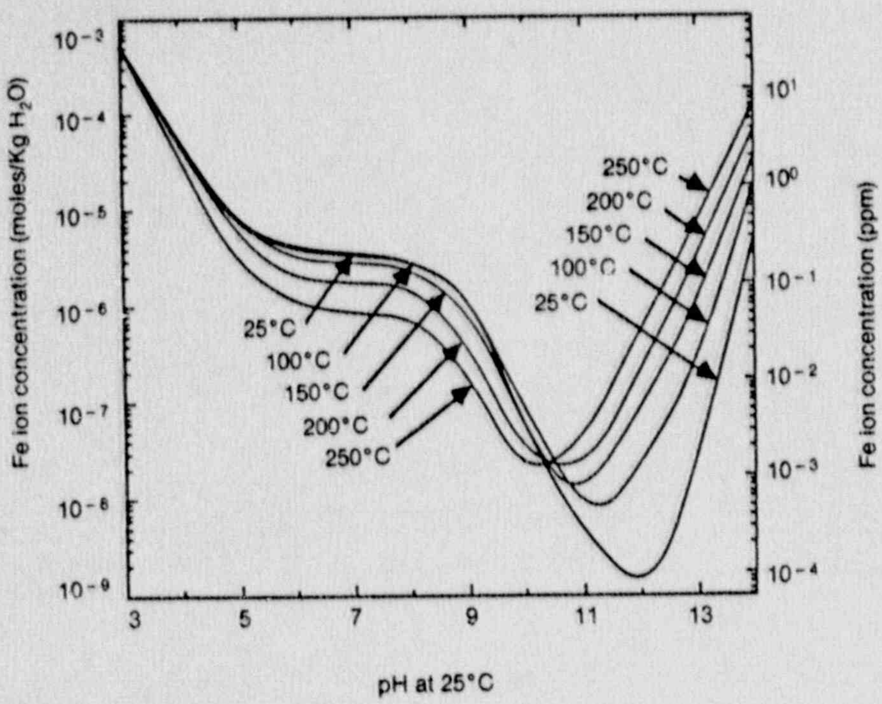


Figure 6.12. Effect of pH on solubility of magnetite in deoxygenated water.

mixing layer and is comparable to the distribution in a bimetallic strip subjected to a uniform temperature change. The resultant axial stresses are presented as the sum of membrane and bending stresses. The portion of the pipe below the mixing layer experiences tensile axial stresses, while the portion of the pipe above the mixing layer experiences predominantly compressive axial stresses. The theoretical maximum stresses are near the mixing layer.

A slight fluctuation in the flow rate causes the mixing layer to be raised or lowered. As the feedwater flow changes, the mixing layer cycles between the top and bottom of the pipe and changes the distribution of the through–wall bending stresses introduced by the stratified flow. Thus, the stratified flow causes low-cycle fatigue damage. Figure 6.13(c) shows the predicted stress distributions when the mixing layer is at 90 degrees [shown in Figure 6.13(d)], and presents the envelope for the distribution as a function of the height of the mixing layer. The dashed line represents the theoretical axial stresses and the solid line represents the actual stresses. The actual stress distribution accounts for the thickness of the mixing layer and the heat transfer taking place in the piping material.

The peak pipe–inside–surface temperature variation is always less than the peak fluid temperature variation, because of the finite value of the heat transfer coefficient; however, it can be relatively large in PWR feedwater systems. Factors affecting the temperature distribution and variation are the finite thickness of the mixing layer, flow–rate changes affecting the height of the mixing layer, and the low–amplitude, high–frequency fluctuations in the mixing layer. Because these factors are not well-known, the actual temperatures are not easily calculated, and on–line monitoring methods are needed to determine the temperature distributions on the pipe surfaces.

The original design of the piping did not consider the effects of stratified flows and, therefore, the fatigue damage in PWR feedwater piping has been greater than originally expected. Circumferential cracks in the feedwater pipes have been found in several PWR plants. The ASME Code design curves for carbon steel may be used to determine the low–cycle fatigue damage caused by stratified flows. (Additional information on design curves is presented in Section 3.4.1.) Also, on–line fatigue monitoring systems have been developed to more accurately assess the low–cycle fatigue damage that is being accumulated in piping systems. One such system has been developed by EPRI and has undergone demonstration tests on the San Onofre 2 (CE PWR) charging system and the Quad Cities 2 (GE BWR) feedwater system.[30,31]

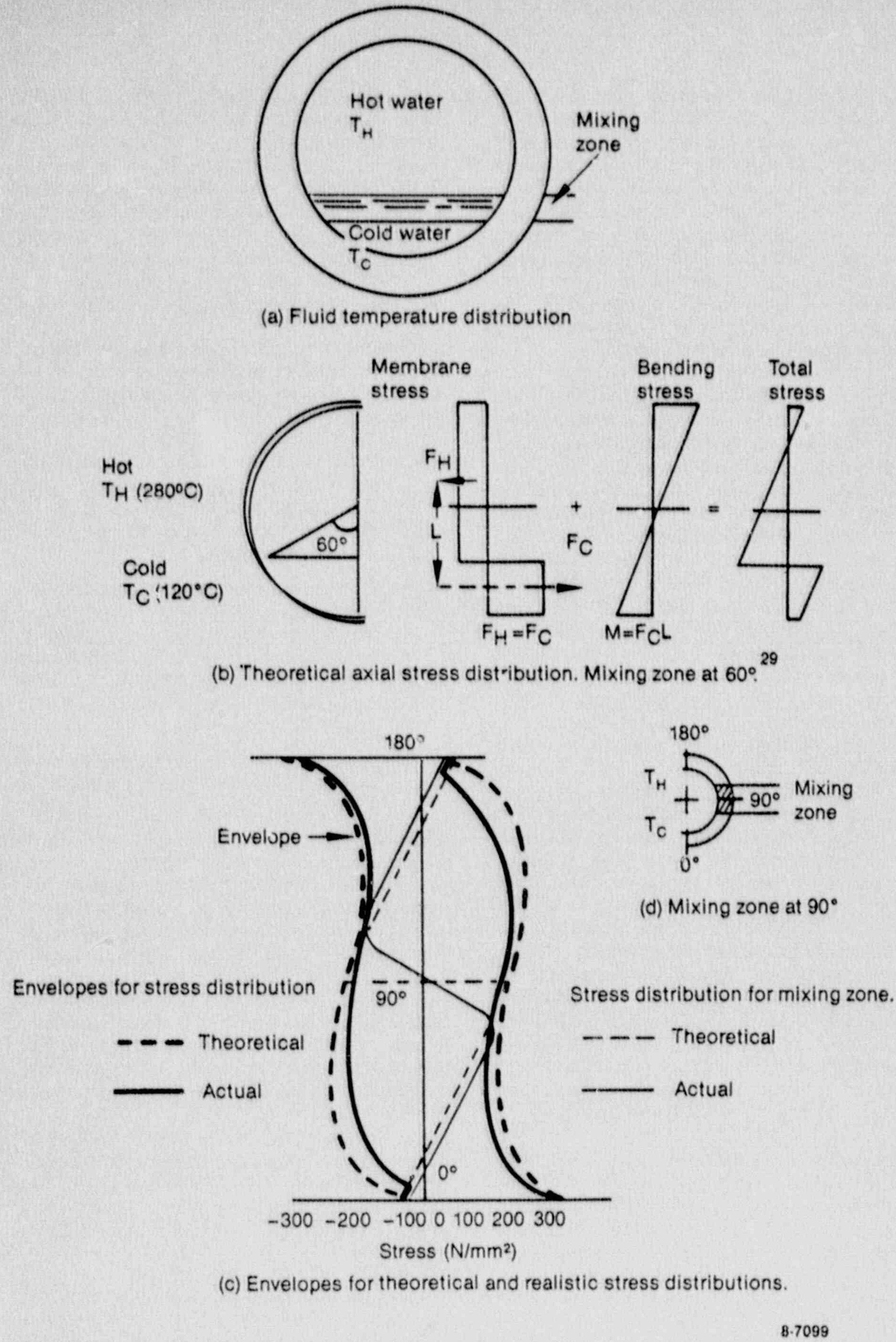


Figure 6.13. Thermal stresses in a pipe with stratified flow.[29]

Carbon steel piping materials may also be susceptible to corrosion fatigue or environmental degradation, if they contain sulfur. (Similar detrimental effects of sulfur in low-alloy pressure vessel steels and steam generator shell material are well-known).[16,32] ASME SA-106 Grade B and ASME A-234 Grade WPB specifications for carbon steel piping materials allow up to 0.058% sulfur content. Fatigue tests were recently conducted in a BWR environment on Japanese piping steels similar to SA-106 Grade B but containing less sulfur. The tests did not show any evidence of environmental degradation.[33]

6.4.3 High-Cycle Fatigue. High-cycle fatigue degradation is caused by the wavy character of the mixing layer in the stratified flows, flow-induced vibrations, and rotating equipment vibrations. The fatigue damage caused by the wavy character of the mixing layer imposes cyclic thermal loads on the inside surface of the piping in the vicinity of the mixing layer. Typical frequencies of the cyclic thermal loads range from 0.1 to 10 Hz.[34] Because of the finite value of the heat transfer coefficient at the inside pipe surface, the peak pipe inside surface temperature variation range is between 25 to 50% of the imposed fluid temperature variations. The actual magnitude of the high-cycle thermal stresses at the inside pipe surface depends on the magnitude of the fluid temperature change, the heat transfer coefficients, the piping layout, and the pipe material properties. These high-cycle thermal stresses primarily affect the pipe inside surface, and attenuate rather rapidly toward the outside pipe surface. Therefore, the corresponding fatigue damage contributes to crack initiation, but not crack propagation. In fact, test results show that in the vicinity of the mixing layer, there is no unique correlation between thermocouple readings at the outside and inside pipe surface.[13] Therefore, the pipe inside surface temperatures cannot be determined from the on-line monitoring of the pipe outside surface temperatures. The cracks initiated by high-cycle fatigue can be propagated by low-cycle fatigue or corrosion fatigue. Circumferential cracks have been found in recent years on the inside surface of the horizontal feedwater piping in several PWR plants.

For many metals, including steels, the fatigue curve flattens at a given number of cycles (10^6 to 10^8 cycles is generally considered typical for steels). The stress at this point is called the fatigue limit. If the alternating stress for a particular event does not exceed the fatigue limit, it is assumed that the member will not fail in high-cycle fatigue, that is, the number of allowable cycles approaches infinity. The carbon steel fatigue design curves in Section III of the ASME Code do not extend beyond 10^6 at this time, and high-cycle fatigue usage was not calculated during the original design of the nuclear piping. The fatigue limit concept is based on materials tested in air; however, the existence of a fatigue limit in the presence of corrosion-assisted fatigue has not been proven. Thus, an approach where the design fatigue curve has a shallow slope (for example, -0.05) beyond 10^6 cycles is being considered by the ASME Code Subgroup on Fatigue Strength. Such an approach is more reasonable to use for long-life fatigue assessment than assuming a fatigue limit.

A number of mechanical and system modifications have been identified by Westinghouse to mitigate thermal striping and flow stratification.[35] These include the following:

1. Protective Liner—Several plants have installed a 406-mm (16-in.) diameter, 13-mm-(1/2-in.-) thick carbon steel pipe inside the feedwater nozzle to protect the nozzle wall from thermal stresses.
2. Heated Feedwater—Several plants have a deaerating feedwater heater (DFH), a large tank that is kept hot during normal operation, to supply makeup water. When a plant has been shut down for a prolonged period, steam from auxiliary boilers can be used to heat the DFH.
3. Some plants have a separate auxiliary feedwater nozzle to supply makeup water during shutdown.

6.4.4 Cavitation. The feedwater pressures in some PWR plants are close to the saturation pressure and the piping in these plants is, therefore, susceptible to a special form of erosion-corrosion damage called cavitation damage. When the feedwater pressure is close to the saturation pressure, bubbles of dissolved gases, such as nitrogen, can form wherever the pressure drops slightly. Such a pressure drop may occur in the condensate polishers or the feedwater heaters, or locally where the flow velocity increases because of turbulence or component geometry. Gas bubbles then condense or collapse when a slight pressure increase takes place. Such pressure increases may take place in pumps or occur locally when the flow velocity decreases sufficiently. Cavitation damage is caused by the formation and collapse of gas bubbles in a liquid near a metal surface. Rapidly collapsing gas bubbles may produce shock waves with pressures as high as 415 MPa (60,000 psi).[36]

Cavitation and corrosion may act synergistically. First, a gas bubble forms near or on a protective oxide film and then the collapsing gas bubble destroys the protective film. The newly exposed metal surface corrodes and a new oxide film forms. Once the metal surface develops a rough point, that point will serve as a nucleus for new bubbles. A new cavitation bubble forms and collapses at the same spot, destroying the newly formed protective film. The exposed metal surface corrodes again. This synergistic process ultimately leads to deep holes in the metal surface. Cavitation damage can be reduced by design changes that minimize hydrodynamic pressure changes in the feedwater piping. Smooth finishes on the metal surfaces are recommended because smooth surfaces do not provide suitable sites for bubble nucleation. Also, smooth finishes at the weld joints in the piping help avoid high local fluid velocities. Using more corrosion resistant materials may also reduce cavitation damage. Piping layouts that avoid sharp bends and tees will also reduce erosion–corrosion damage.

6.4.5 Galvanic Corrosion.[36] Sections of carbon steel piping in a number of PWR feedwater systems have been replaced with stainless steel piping. Such replacements introduce dissimilar metal welds, which generally accelerate the corrosion of the more active metal (the carbon steel) and reduce the attack on the more noble metal (the stainless steel). The susceptibility to damage incurred by carbon steel piping depends on how far apart it is from stainless steel in the galvanic series. The conductivity of the feedwater determines the magnitude of the electrical current flowing between the carbon steel and the stainless steel. The feedwater conductivity also determines the length of carbon steel piping affected by galvanic corrosion. In quite pure or high-resistance feedwater, the galvanic corrosion attack causes a sharp groove to form near the weld.

6.5 Potential Failure Modes

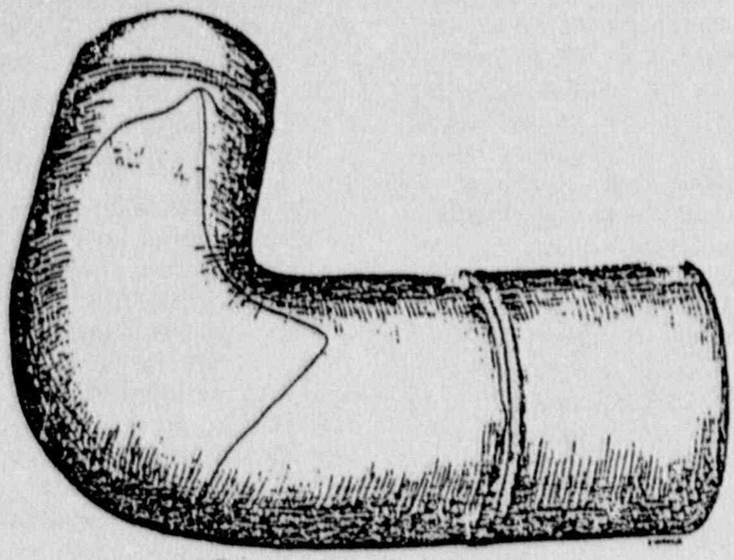
As discussed in the Section 6.4, two aging mechanisms, erosion–corrosion and fatigue, cause most feedwater piping degradation. Occasionally the aging degradation does not produce failure, but so weakens the system and reduces the safety margin that another event, such as a pressure pulse or a water hammer, is the final cause of a rupture.

The worst failure scenario (one that has never occurred at any plant) would be a complete rupture near the feedwater inlet nozzle to the steam generator, located downstream of the check valve. Some plants have check valves on the feedwater systems inside the containment, whereas other plants have the check valves located just outside the containment. Such a failure could not be isolated from the steam generator, and a complete blowdown of the steam generator would result. For some break locations, and depending on the feedwater and auxiliary feedwater system designs, the break can be isolated and auxiliary feed flow to the steam generator established. A less severe case would be a leak in the feedwater line, but not a complete pipe rupture, so that at least some feedwater flow to the steam generator could be maintained.

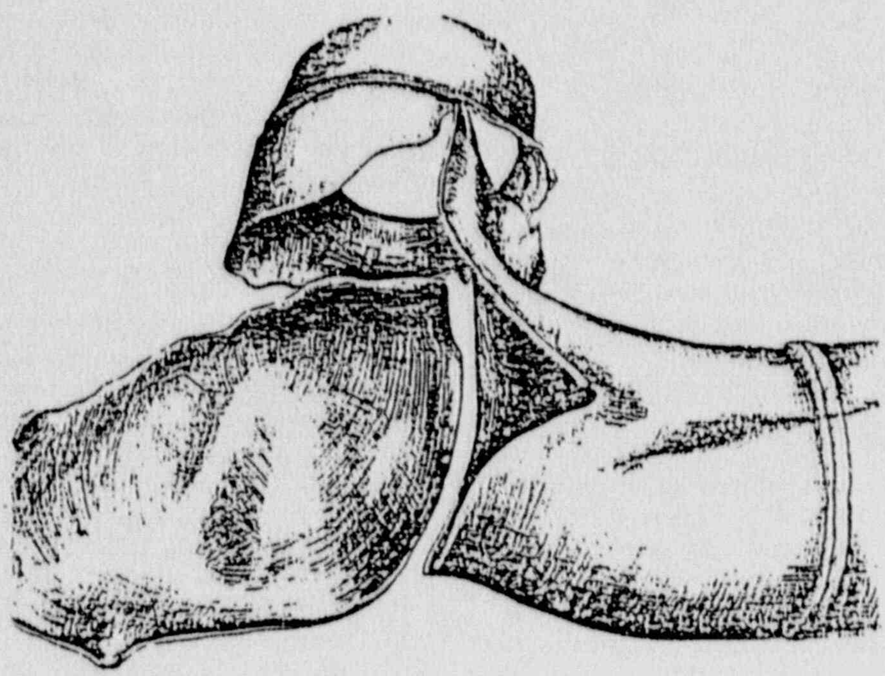
6.5.1 Erosion–Corrosion Failures. Erosion–corrosion caused the catastrophic rupture of feedwater piping at the Trojan plant in 1985[37] and the Surry 2 plant in 1986.[38] A pressure pulse caused the ultimate rupture of feedwater piping already significantly degraded by erosion–corrosion at both plants. In neither case was there a warning of incipient failure, such as a preliminary leak. Because there had been little or no inservice inspection of the majority of feedwater system piping at these plants, the extent of wall thinning was not known before the ruptures occurred. (This situation is changing as many utilities are now inspecting their feedwater piping.) The Trojan and Surry 2 failure events are discussed in the next few paragraphs.

A main feedwater isolation following a turbine trip at the Trojan plant produced a pressure pulse that reached a maximum total pressure of approximately 6.13 MPa (875 psig) in the heater drain and feedwater system.[37] The pressure surge ruptured an eroded 368-mm- (14.5-in.-) diameter section of SA-106 Grade B carbon steel pipe in the feedwater heater drain pump discharge piping system. A steam–water mixture was released into the turbine building. The system flow velocity was 6.1 to 7.3 m/s (20 to 24 ft/s), and the normal operating pressure and temperature at the time of the break were about 3.2 MPa (450 psig) and 177°C (350°F), respectively. The ruptured portion of the piping section had been eroded from a nominal thickness of 9.5 to about 2.5 mm (0.375 to about 0.098 in.). Some of the thinning may have occurred during rupture. One worker received first- and second-degree burns from the high-temperature fluid.

A main steam isolation valve failed by closing at the Surry 2 plant, and the resulting increased pressure in the steam generator collapsed the voids in the water. This caused the system pressure to surge beyond the normal operating pressure and led to a catastrophic failure of a 460-mm- (18-in.-) diameter, 13-mm (0.5-in.) design thickness carbon steel, ASTM A-234 Grade WPB elbow in the suction line to the main feed pump (see Figures 6.4 and 6.14). The reactor was at full power and the feedwater was single phase, with a flow velocity of about 4.3 m/s (14 ft/s), a pH level in the range of 8.8 to 9.2, an oxygen content of about 4 ppb, and a coolant temperature and pressure of approximately 188°C (370°F) and 3.2 MPa (450 psig), respectively. The examination of the ruptured elbow



(a) Rupture lines in intact pipe.



(b) Pipe after rupture.

Figure 6.14. Surry pipe rupture.

showed that the wall thinning was relatively uniform except in some local areas. The wall thickness of the elbow was reduced from a nominal 13 mm (0.5 in.) to 0.38 to 1.22 mm (0.015 to 0.048 in.) in small localized areas and to 2.3 mm (0.09 in.) in larger areas.[5,38] Eight workers were burned by flashing feedwater; four of whom subsequently died. The flashing feedwater interacted with and disrupted the fire protection, security, and electrical distribution systems.[39]

As a result of the Surry incident, the NRC staff asked that all utilities with operating nuclear plants inspect their high-energy carbon steel piping. The degraded components, fittings, and straight runs in the feedwater-condensate systems identified in that inspection and reported to the NRC are listed in Table 6.3.[40] A summary of the inspection programs and inspection results has been compiled by EPRI.[41]

New piping was installed at several locations in the Surry 2 feedwater system as a result of the pipe break. During the September 1988 outage, an elbow (installed in 1987) on the suction side of one of the main feedwater pumps was found to have lost 20% of its 13-mm (0.5-in.) wall in 1.2 years. The NRC preliminarily concluded that this abnormally high rate of wall thinning may have coincided with a reduction in feedwater dissolved oxygen concentration.[42] However, Virginia Power disagrees that the oxygen content was a major contributor. One possible explanation was that thorough cleaning of the carbon steel piping installed in 1986 and 1987 prevented or delayed a buildup of a protective layer of magnetite.[43] Another explanation is that the accelerated thinning could have been aggravated by feedwater flowing into the steam generators that bypassed the feedwater heaters. This would have reduced the water temperature from its normal 190°C (370°F) to about 150°C (300°F).[44] Later in the September 1988 outage, Virginia Power replaced a total of 125 piping segments with steel piping containing 2.5% chromium.

Apart from the feedwater piping, carbon steel J tubes and feed rings within the recirculating steam generators have experienced erosion–corrosion-induced damage. The J tube problem has likely been corrected by replacing the original J tubes with ones made of stainless steel or Alloy 600. However, concerns persist that the the welds between the new J tubes and the feed rings may have introduced geometric discontinuities on the inside surface of the feed rings. Such discontinuities could generate turbulence in the feedwater and cause erosion–corrosion damage in the carbon steel feed rings.

6.5.2 Fatigue Failures. Water hammer events, stratified flow, thermal shock, flow-induced vibration, and equipment vibration can all cause fatigue damage that may ultimately lead to leakage of the feedwater. However, a pipe section significantly weakened by fatigue damage may also fail catastrophically if subjected to a water hammer or a pressure pulse.

The feedwater piping-to-steam generator nozzle connections have been particularly susceptible to thermal fatigue damage. In 1979, the Indiana & Michigan Power Company discovered leaking circumferential cracks in the upper half of two 410-mm (16-in.) feedwater lines in the immediate vicinity of the steam generator nozzles at the D. C. Cook Unit 2. Subsequent radiographic examinations revealed crack indications at similar locations in all the feedwater lines of both D. C. Cook Units 1 and 2. The most severe crack was a through-wall circumferential crack, 890-mm (3.5-in.) long at the outer surface. This crack initiated at a discontinuity introduced in the piping elbow from machining the weld end preparation counterbore in the base metal outside the weld heat-affected zone (see Figure 6.15). The crack propagation was transgranular, and there was some evidence that corrosion might have played a secondary role in the failure process. Figure 6.16 shows two actual crack profiles in the degraded feedwater pipes at two PWR plants.[35] The most extensive cracking was found in the upper portion of the pipe cross section. The backing strip was removed in the redesign, and the sharp discontinuity where the crack initiated was replaced with a blend radius. Further inspections during 1980 revealed pipe cracks or fabrication defects requiring repair in the vicinity of the feedwater nozzles at 14 of 25 Westinghouse PWR facilities and two of eight Combustion Engineering facilities. Many units experienced lengthy outages in 1979 and 1980 while these inspections and repairs were performed. In addition, nozzle cracking was discovered at the St. Lucie plant in 1983[45] and at both the Turkey Point 3 and 4 units in 1984. The cracking was attributed to thermal stratification and occurred in plants that had been operating from 1 to 19 years. A summary of PWR feedwater line cracking is presented in Table 6.4.

Thermal sleeves at the feedwater inlet to the steam generator have been damaged by thermal shock, stratified flow, flow-induced vibration, and water hammer events. Piping supports have been damaged by water hammer events and large thermal deflections. The piping at anchor point locations (such as containment penetrations) is particularly susceptible to water hammer and thermal deflection loadings. For example, a water hammer transient at the Indian Point Unit 2 in 1973 resulted in a 180-degree circumferential fracture of a 460-mm- (18-in.-) diameter main feedwater line

Table 6.3. PWR plants with pipe wall thinning in the feedwater–condensate systems[40]

Plant	Unit	Commercial Operation	Degraded Components (Fittings, Straight Runs)
Arkansas Nuclear One	1	August 1974	Elbows, drain pump discharge piping
Arkansas Nuclear One	2	December 1978	Undefined
Calvert Cliffs	1	October 1974	Elbows, reducers, straight runs
Calvert Cliffs	2	November 1976	Elbows, reducers, straight runs
Callaway	—	October 1984	Recirculation line elbows
Diablo Canyon	1	April 1984	Elbows, straight runs
Diablo Canyon	2	August 1985	Elbows, Y
Donald Cook	2	March 1978	Elbows
Ft. Calhoun	—	August 1973	Elbows, straight run
Haddam Neck	—	July 1967	Recirculation line
Millstone	2	October 1975	Elbows, heater vent piping
North Anna	1	April 1978	Elbows, straight runs
North Anna	2	June 1980	Elbows, straight runs
H. B. Robinson	2	September 1970	Recirculation lines
Rancho Seco	—	September 1974	Straight runs downstream of feedwater isolation valves or main feedwater pumps minimum flow valves
San Onofre	1	June 1967	Reducers, heater drain piping
San Onofre	2	July 1982	Heater drain piping
San Onofre	3	August 1983	Heater drain piping
Salem	1	December 1976	Recirculation line
Salem	2	August 1980	Recirculation line
Shearon Harris	—	October 1986	Recirculation line
Surry	1	July 1972	Fittings
Surry	2	March 1973	Fittings

Table 6.3. (continued)

Plant	Unit	Commercial Operation	Degraded Components (Fittings, Straight Runs)
Sequoyah	1	July 1980	Elbows, straight runs
Sequoyah	2	November 1981	Elbows
Trojan	—	December 1975	Elbows, reducers, straight runs
Turkey Point	3	October 1972	Feedwater pump suction line fittings

at the anchor point where the pipe penetrated the reactor containment structure.[11] The water that sprayed from the ruptured pipe caused gross thermal deformation of the metal containment liner near this juncture. The water hammer also produced a large bulge in the horizontal run of the main feedwater pipe to the steam generator nozzle. The crack at the anchor point of the containment wall was caused by excessive bending stresses, possibly resulting from dynamic reaction forces at the support points along the line.

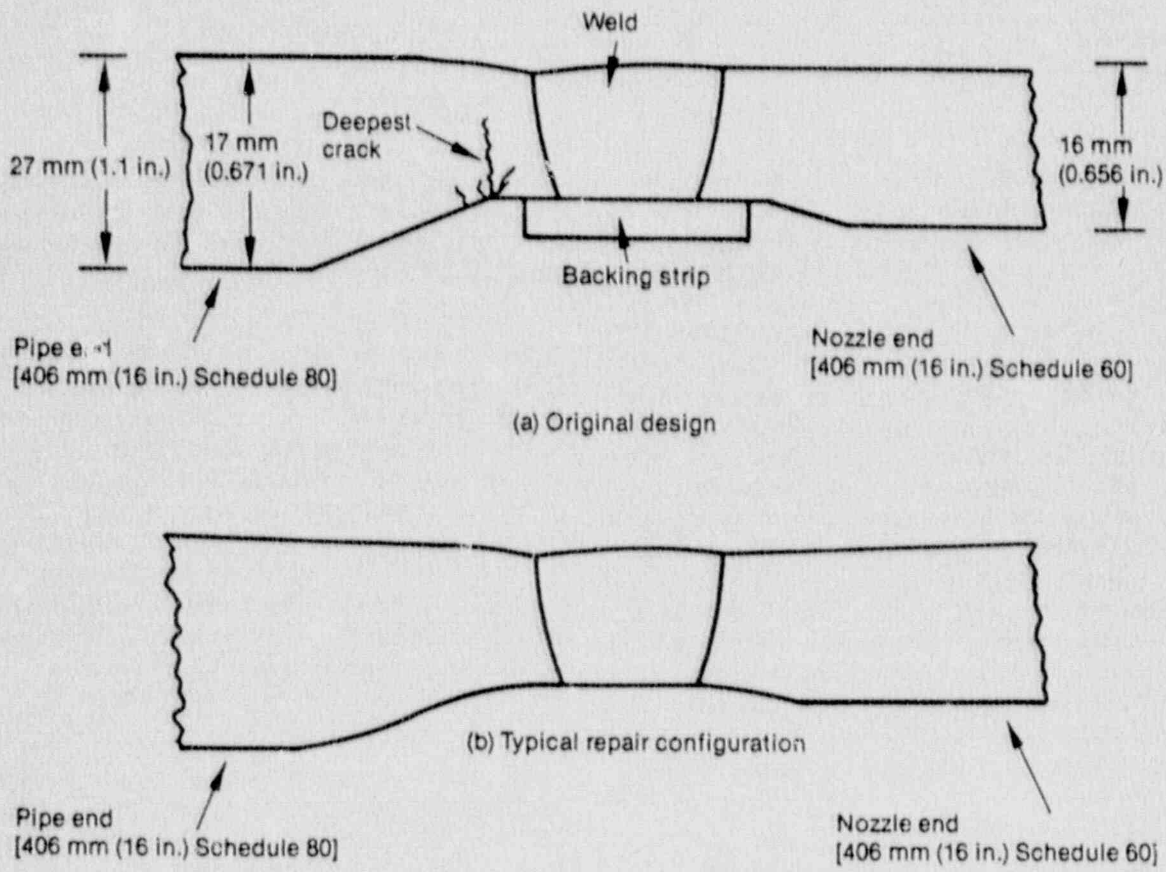


Figure 6.15. Crack location in D. C. Cook nozzle.[11]

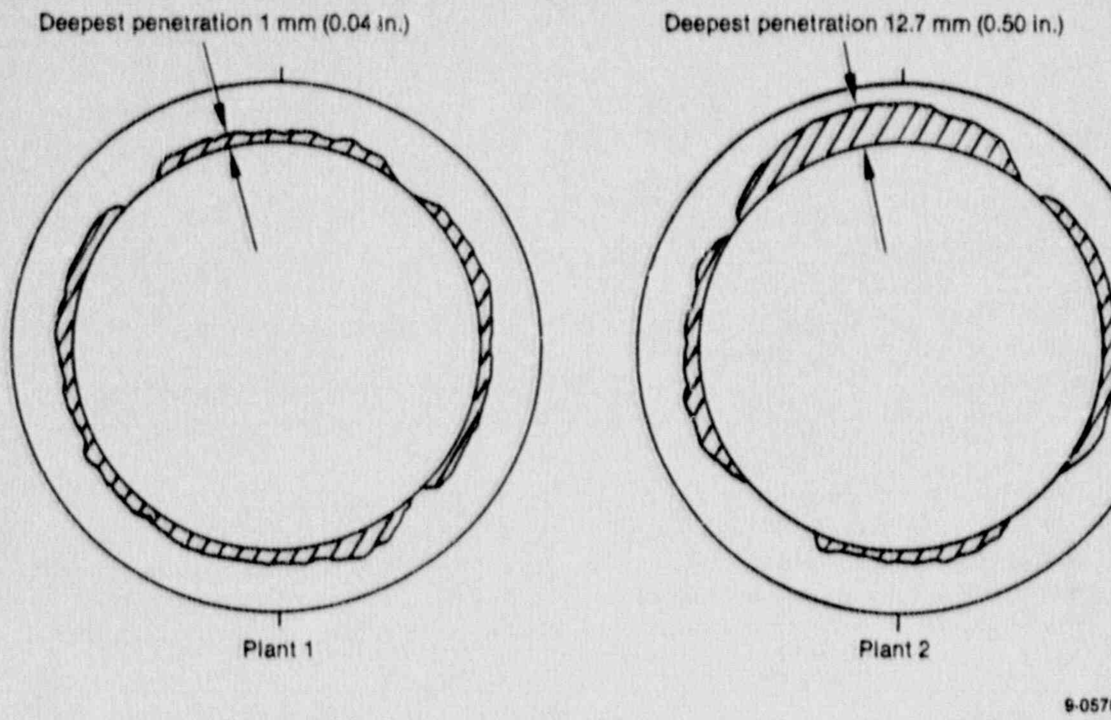


Figure 6.16. Crack profiles in degraded feedwater piping.

The Indian Point Unit 2 water hammer resulted from a steam-cold water interaction in the feedwater piping adjacent to the steam generator. When the level in the steam generator dropped below the feed ring, sparging holes on the underside of this ring allowed water to drain rapidly from the ring and from the horizontal feedwater piping outside the steam generator. The feed ring and line then refilled with steam from the steam generator. Subsequently, introduction of cold auxiliary feedwater (to restore steam generator level) allowed the damage to occur. To preclude the recurrence of water hammer shocks, the long horizontal run of feedwater piping outside the steam generator was eliminated and the feed ring was modified to prevent rapid draining. This modification included plugging the sparging holes on the underside of the feed ring and installing J tubes on the top of the ring. In fact, the steam generator feed rings (spargers) were modified at all operating Westinghouse units in response to the water hammer event at Indian Point 2.

In November 1985, slug flow in the feedwater system of the San Onofre Unit 1 plant struck the standing water at a filled location, which produced a travelling pressure wave that generated very high loads. The feedwater piping in the B steam generator loop experienced the worst loads because of a long horizontal run of piping. The 254-mm (10-in.) diameter pipe inside the containment was distorted from its original configuration, pipe supports were damaged, and a 2-m- (80-in.-) long crack was generated.[35]

Modifications have also been made in Combustion Engineering units. In May 1979, at Calvert Cliffs 1 the steam generator feedwater ring was modified by adding thirty-six 90-degree elbows to the top of the ring and plugging 72 discharge nozzles on the bottom of the ring to minimize water hammer events. Other Combustion Engineering units have made similar modifications. In 1983, the Number 2 main feedline at the Maine Yankee plant experienced a water hammer rupture.[46] Each of the steam generator feed rings was subsequently modified by closing off the 76 bottom nozzles and installing 28 top-mounted J tubes.[45]

Damage to struts and snubbers supporting the auxiliary feedwater supply lines occurred in 1985 at the Waterford 3, Diablo Canyon 1, San Onofre 3, and Davis Besse plants.[47] The origin of the damage has been attributed to water slugs formed from condensation of steam in cold lines. During an inspection at the Palisades plant, the following auxiliary feedwater system damage was confirmed, as shown in Figure 6.17:

Table 6.4. PWR feedwater piping cracks[11]

Plant	Maximum Depth[a] (in.)	Location	Lines Cracked[b]	Piping Component	Comments
Westinghouse					
D.C. Cook 1, 2	Through–wall	Top	8 of 8	Elbow	2 cracks through–wall
Beaver Valley 1	0.400	9 o'clock	3 of 3	Elbow	—
Kewaunee	0.050	7 o'clock	2 of 2	Pipe	3–in. auxiliary feed near SG inlet
Point Beach 1, 2	0.047	3 o'clock	2 of 2	Reducer	3–in. auxiliary feed near SG inlet
H.B. Robinson 2	0.750	9 o'clock	3 of 3	Reducer	Shallow cracking of nozzle under thermal sleeve
Salem 1	0.235	4 of 4	—	Elbow reducer	—
San Onofre 1	0.100	Lower half of reducer	3 of 3	Reducer	Multiple–branched cracks, fatigue
Surry 1, 2	0.080	2 and 5 o'clock	6 of 6	Reducer	—
Ginna	0.107	8:30 o'clock	2 of 2	Elbow	—
Zion 1,2	0.088	Not reported			
Combustion Engineering					
Millstone 2	0.250	12 o'clock	2 of 2	Pipe	—
Palisades	0.170	3 and 9 o'clock	2 of 2	Pipe	Cracks also found at weld in vicinity of horizontal pipe

a. The typical thickness of a feedwater line pipe wall is approximately 13 to 25 mm (0.5 to 1 in.).

b. Number of total feedwater lines into steam generators that were found to be cracked. For example, the D.C. Cook plants are 4–loop Westinghouse units, so all eight lines in the two plants were cracked.

- Thermal sleeve cracked (see 3 in Detail A)
- One of the three holddown clamps for sparger missing (see Detail B)
- Weld at elbow broken (see 1 in Detail A)
- Clamp broken on riser pipe to sparger (see 2 in Detail A).

An inspection conducted prior to the discovery of the internal steam generator damage revealed that eight hangers on the auxiliary feedwater piping also were loose or damaged. These hangers were inspected before the beginning of the fuel cycle and were considered in good repair at that time. The damage described above is consistent with the occurrence of a water hammer during the previous fuel cycle. This failure event is one of approximately 30 water hammers that have occurred in recirculating steam generators with the feedwater nozzle located above the tube bundle.

6.6 Inservice Inspection and Surveillance Methods

The ASME Section XI guidelines for inspection of pressure piping are listed in Tables IWB-2500-1, IWC-2500-1, IWD-2500-1 of Reference 48, for Class 1, 2, and 3 systems, respectively. The feedwater piping inside the containment is a Class 2 system and only the weld areas must be inspected. The examination requirements for the pressure-retaining welds in Class 2 carbon steel piping systems are listed in Table 6.5. Although the ASME Code does not require that regions of the piping away from the weld zones be inspected, most utilities have instituted increased inspection programs[41] for their feedwater system piping in response to NRC Bulletin 87-01.[40] The ASME Code Section XI Committee is currently developing new requirements and standards for monitoring erosion-corrosion in safety related secondary-side piping.

There are four 10-year inspections required during the 40-year operating life of a nuclear plant. For piping systems, all locations where the calculated stress intensity exceeds 2.4 S_m (S_m is the maximum

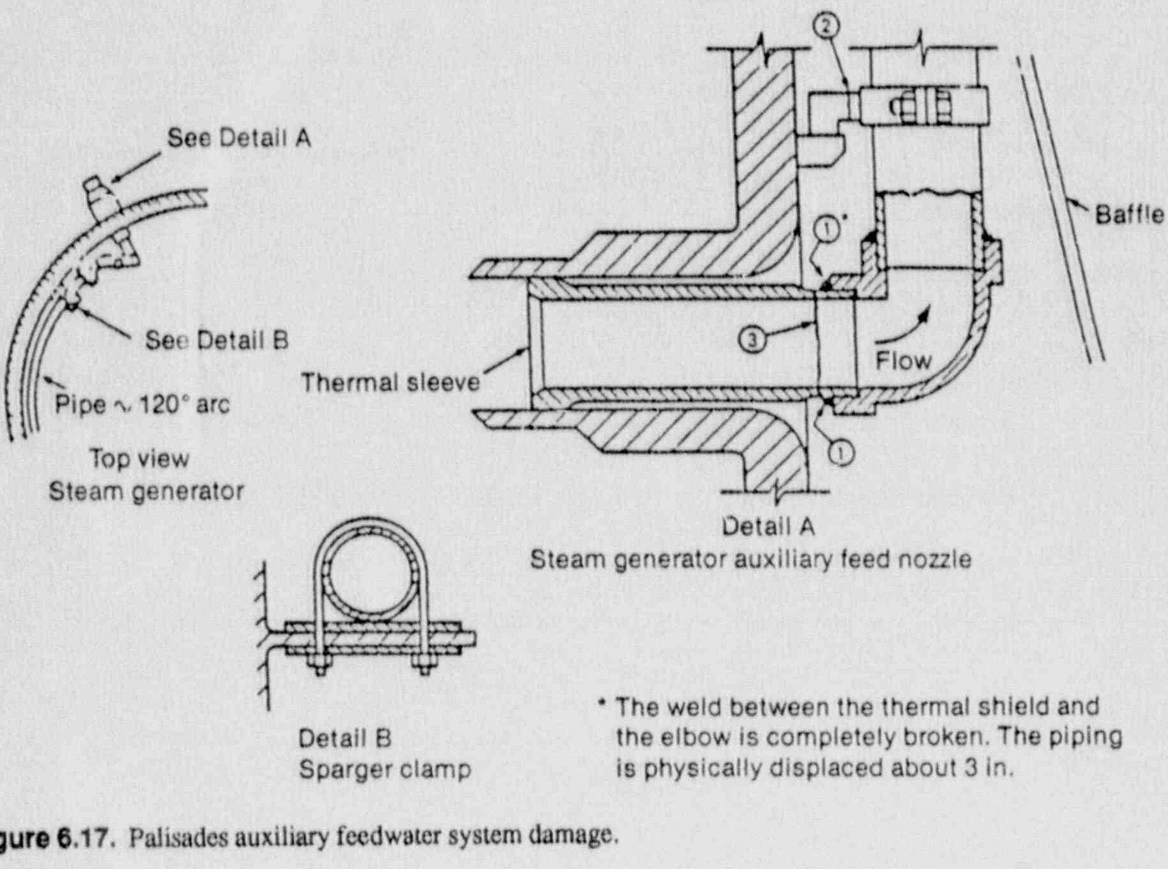


Figure 6.17. Palisades auxiliary feedwater system damage.

Table 6.5. Required inservice inspections for Class 2 piping[48]

Parts Examined	Method	Extent[a]	Frequency[a,b]
Circumferential weld	Surface and volumetric	100% of each weld requiring examination	Each inspection interval
Longitudinal weld	Surface and volumetric	2.5 t at the intersecting circumferential weld[c]	Each inspection interval
Socket welds	Surface	100% of each weld requiring examination	Each inspection interval

a. The welds selected for examination shall include 7.5%, but not less than 28 welds, of all carbon and low–alloy steel welds.

b. The welds selected for examination shall be reexamined during subsequent inspection intervals over the service lifetime of the piping component.

c. The longitudinal weld is inspected for a length of 2.5 times the wall thickness (t) at its intersection with the circumferential weld.

allowable primary membrane stress intensity as defined in Section III of the ASME Code), or the calculated cumulative fatigue usage factor exceeds 0.4, must be included in the inservice inspection (ISI) program.[48] All of the nozzle–to–safe–end butt welds are also included in the ISI program. The ISI examinations for these locations consist of 100% volumetric preservice examinations of all welds followed by a 100% volumetric examination of a specified sample at each of the four 10–year intervals per ASME Section XI requirements. Unfortunately, these programs may not adequately detect the full extent of the degradation caused by erosion–corrosion, because the wall thinning from erosion–corrosion is often highly localized.

The ASME Code[7] (Paragraphs NB–3622, NC–3622, and ND–3622) and the ANSI Standard[6] (Paragraph 101.5) also require that piping be observed under initial or startup conditions to ensure that any vibration is within acceptable limits. The USNRC has published piping vibration testing requirements in several regulatory guides.[49,50] The ASME has also written an operation and maintenance standard[51] that lists the requirements for vibration testing of nuclear power plant piping systems. This standard addresses steady–state and transient vibration testing, acceptance criteria, methods for determining acceptable vibration limits, and recommendations for corrective action. Visual qualification inspectors witness the piping response during applicable flow modes. They may use portable vibration monitoring equipment as an aid.[14]

With respect to the thermal sleeve issue, Westinghouse has recommended to its plant owners that the loose–parts monitoring systems be operable and that nondestructive examinations be performed to assess the thermal sleeves.[52]

Inspection procedures are being developed to detect erosion–corrosion damage in piping. Manual ultrasonic techniques can be used to measure average thicknesses, but in the past these techniques could not be satisfactorily used to determine minimum thicknesses.[27] Because of the localized nature of erosion–corrosion damage, there was a high probability that a minimum thickness site would not be detected. Also, the manual ultrasonic technique sometimes lacked repeatability and reliability because it is so operator dependent. However, there has been considerable improvement in ultrasonic inspection accuracy in recent years. Comparison of current ultrasonic measurements with mechanical measurements indicates an error of 3 to 5% of the wall thickness. Controlled test results show that ultrasonic measurements now have a repeatability within 1% of the wall thickness.[53] However, these methods do not provide 100% inspection coverage of the susceptible sites, and therefore they may not be able to detect the minimum wall thickness, that is, the maximum erosion–corrosion damage. Development has begun on a new ultrasonic inspection method, a modified portable automated remote inspection system (PARIS) using a flexible transducer array.[54] The flexible transducer array can conform and acoustically couple to the complex geometries of elbows and tees. Laboratory results show that this new ultrasonic method can inspect carbon steel piping rapidly, with 100% coverage. Field demonstrations of this new inspection method are needed. The use of an ultrasonic technique requires removal of the insulation.

Two other nondestructive evaluation techniques available to detect wall thinning are (a) high–energy radiography through the insulation of a water–filled pipe and (b) high–energy or isotope radiography through the insulation of an empty pipe.[27] The tangential radiographic technique has been used to measure wall thicknesses to within 0.076 mm (0.003 in.) in small–diameter, thick–walled pipe. High–energy radiation sources are used to inspect large–diameter [>203–mm (8–in.)] pipe. The perpendicular radiographic technique can detect abrupt changes in thickness within 2% of the wall thickness. A calibration curve of thickness versus density is required for accurate measurements.

All locations in the feedwater piping susceptible to erosion–corrosion should be identified. Most utilities are using the CHEC computer code developed by the Electric Power Research Institute (EPRI) to identify the sites most susceptible to erosion–corrosion.[55,56] The sites identified by CHEC are supplemented by sites identified by engineering judgment and by the experience at other plants such as Trojan and Surry. EPRI has also developed guidelines on selection of examination techniques for specific plant situations (including ultrasonic, radiographic, and visual methods), and has provided suggestions for additional detailed examinations if erosion–corrosion is detected.[53] The results of these thickness measurements should be evaluated against the highest possible pressure transients, because, ultimately, such transient pressures may cause catastrophic failure of degraded pipes.[2] As of January 1, 1988, 95 of the 113 commercial LWRs had completed an analysis using the CHEC code to identify the 15 most susceptible locations. As of June 1, 1988, 81 plants had inspected the susceptible sites.

An on–line monitoring method to monitor wall thinning caused by erosion–corrosion is needed because there is significant uncertainty (50%) in predicting erosion–corrosion rates in carbon steel feedwater piping.[57] Isotope implantation is one such on–line monitoring method currently being developed.[58] Isotope implantation involves use of minuscule amounts of tracers, which are embedded at two different depths in pipe walls at sites susceptible to erosion–corrosion, as shown in Figure 6.18. The tracers are released into the feedwater when they are exposed by pipe thinning. The location and rate of thinning can be determined by the use of different isotopes at different sites. The tracers are detected by several on–line gamma spectrometers. There is a concern with the usefulness of the technique because it requires drilling small holes in the piping wall to implant the tracers.

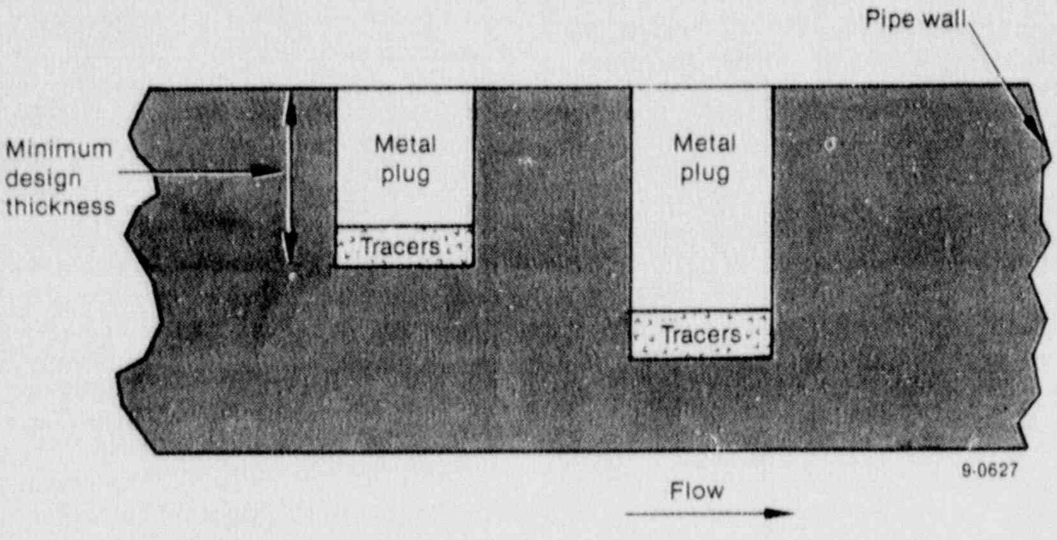


Figure 6.18. Isotope implantation in feedwater piping.

As discussed in previous sections of this chapter, the feedwater piping base metal can experience significant fatigue damage caused by stratified flows and thermal shocks. Therefore, inspections of only the welds (as required by the ASME Code) are probably not adequate, and effective inspection of the base metal may be impractical. As discussed earlier in this chapter, monitoring of the piping outside surface temperatures does not provide sufficient data to determine the cyclic thermal stresses on the inside surface. Therefore, the use of acoustic emission monitoring or other advanced techniques to detect fatigue crack growth in PWR feedwater piping systems needs to be evaluated.

6.7 Summary, Conclusions, and Recommendations

Significant feedwater piping degradation caused by erosion–corrosion (including flow–assisted corrosion and cavitation damage); stratified flow and thermal shock–induced fatigue; and mechanical fatigue caused by flow–induced and mechanical vibrations and water hammer events has occurred. In many cases, these factors were not adequately considered in the plant design and safety analysis, and the required inservice inspections have not been adequate to detect the degradation before the piping failed. This aging degradation has occasionally resulted in catastrophic failure of a feedwater pipe. Fatigue analyses were (and still are) not required, nor are there any explicit requirements to evaluate high–cycle vibration and fatigue except in the initial testing phase of the systems. Water hammer events also cause fatigue damage and must be examined when determining the residual life of a system. The phenomena and extent of degradation in PWR feedwater lines are not sufficiently defined (in terms of plant parameters and cycles), to quantitatively predict feedwater system lifetimes. Nor have most secondary system piping segments been inspected with great rigor. Therefore, the potential exists for a PWR feedwater system to generate degradation that will allow a dynamic event, such as an earthquake or a water hammer, to suddenly fail a pipe, with no advanced warning such as a leak before break.

A broad–based approach has been taken to resolve these problems. An NRC Bulletin was issued that requires utilities to institute more detailed inspection plans for secondary system piping. EPRI has developed the CHEC computer code to assist in identifying areas to be inspected. This code is being used by utilities, in conjunction with engineering judgment and experience in other plants (e.g., Trojan), to select the sites for more detailed inspections. EPRI has also assisted utilities by evaluating the type of nondestructive testing methods that might be used for these inspections. Most utilities have completed initial inspections of their feedwater and condensate piping. Finally, the ASME Section XI Committee is drafting revised guidelines for the inspection of secondary–side piping.

The degradation sites for the feedwater system are ranked and listed in Table 6.6. The feedwater nozzle and piping inside containment are ranked the highest, because a break at this point cannot be isolated from the steam generator and results in rapid blowdown of the steam generator. The piping near fittings and geometric discontinuities is ranked next because of the erosion–corrosion problems that have occurred at those locations.

The conclusions and recommendations related to degradation damage in PWR feedwater piping are as follows:

1. Severe erosion–corrosion degradation of carbon steel feedwater piping can occur and may lead to catastrophic failure. The erosion–corrosion damage can be very localized. Reliable nondestructive inspection methods are being developed that effectively provide 100% coverage of the area under investigation and ensure that minimum wall thicknesses are detected. The results of thickness measurements should be evaluated considering the highest possible transient pressure.

2. Use of on–line monitoring methods to determine erosion–corrosion damage needs to be evaluated because of significant uncertainty regarding the erosion–corrosion rates. Thickness measurements should be used to assess the current wall thinning models and revise the guidelines, as needed, for identifying the sites that are susceptible to erosion–corrosion. On–line monitoring methods are not needed if the erosion–corrosion damage is effectively mitigated.

3. The secondary water chemistry (including pH level, oxygen content, and impurities), temperature, and bulk flow velocity; the piping layout; the smoothness of the piping inside surfaces; and the chemical composition of the piping material affect the rate of erosion–corrosion damage. Control of these

Table 6.6. Summary of degradation processes for PWR feedwater piping and nozzles

Rank	Degradation Sites	Stressor	Degradation Mechanisms	Potential Failure Modes	ISI Methods
1	Feedwater nozzle and piping inside containment, sites in horizontal piping runs in vicinity of mixing layer	Flow velocity, O_2 content and pH level in feedwater, impurities, stratified flows, thermal shocks, water hammer, thermal transients	Erosion–corrosion, high- and low-cycle thermal fatigue, mechanical fatigue, mechanical overload	Rupture from wall thinning, leakage through fatigue cracks, rupture caused by water hammer	Ultrasonic testing, radiography[a]
2	Feedwater piping near fittings	High flow velocity, O_2 content and pH level in feedwater, impurities, water hammer, thermal transients	Erosion–corrosion, mechanical and thermal fatigue	Rupture from wall thinning, leakage through cracks	Ultrasonic testing, radiography[a]
3	Geometric discontinuities on inside surface of piping	Flow velocity, O_2 content and pH level in feedwater, impurities, water hammer	Erosion–corrosion, mechanical fatigue	Rupture from wall thinning	Ultrasonic testing, radiography[a]

a. Currently being performed but not included in ISI requirements.

parameters can mitigate carbon steel erosion–corrosion damage. However, a change in one of the system parameters, such as water chemistry or temperature, may have adverse affects on other plant components. For example, an increase in the oxygen content in the feedwater will tend to reduce the feedwater piping erosion–corrosion damage but may degrade the steam generator tubes. Also, the fatigue–crack–growth rate in carbon steel piping may increase with an increase in oxygen content. Obviously, caution is warranted prior to implementing any changes in system parameters.

4. The use of stainless steel coatings needs to be evaluated as a method to mitigate erosion–corrosion damage to feedwater piping. Stainless steel coatings have been successfully used in some foreign power plants to eliminate erosion–corrosion problems in steam lines.

5. The inside surfaces near any repair welds should be as smooth as possible. Rough inside surfaces can create turbulence in the flow that may induce flow–assisted corrosion; and if the fluid temperature is near saturation, they may provide nucleation sites for formation of gas bubbles that subsequently collapse and cause cavitation damage.

6. The feedwater piping and nozzles also are subjected to fatigue damage from stratified flow, thermal shock, flow–induced vibration, and equipment vibration loads. The fatigue damage will ultimately lead to leakage of feedwater under normal operation. However, a pipe section significantly weakened by fatigue damage may fail catastrophically if subjected to a water hammer or a pressure pulse. Acoustic monitoring of the feedwater nozzles and horizontal portions of the piping may help to detect any crack growth.

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7. PRESSURIZED WATER REACTOR CONTROL ROD DRIVE MECHANISMS AND REACTOR INTERNALS

A. G. Ware

The pressurized water reactor (PWR) control rod drive mechanisms (CRDMs) position the neutron absorbing control rod assemblies (CRAs) within the reactor core to adjust the core reactivity. The reactor internals support the reactor core, maintain fuel assembly alignment, and direct the coolant flow within the reactor vessel. This chapter describes the design of the various types of PWR CRDMs and reactor internals and then discusses the aging stressors, degradation sites and mechanisms, potential (and actual) failure modes, and inservice inspection requirements associated with these devices. Finally, activities and projects are suggested that should lead to a better understanding, control, and mitigation of the aging degradation process in PWR CRDMs and reactor internals.

7.1 Description

The PWR CRDMs are located at the top of the reactor pressure vessel, as shown in Figure 7.1. Each CRDM is linked to its CRA by a detachable coupling. A CRA can be withdrawn or inserted by its CRDM at speeds consistent with the reactivity changes required for reactor operation, or held at a desired location. The coupled CRAs and CRDM drive rods can also be released to drop into the core by gravity for maximum negative reactivity insertion (scram). Thus, they play a critical role in mitigating operational transients and accidents. Various core designs may have more than one type of CRAs. For example, there may be axial power shaping rods, shim rods, or shutdown rods. CRDMs fall into three basic design types: the roller nut–lead screw, the rack–and–pinion, and the magnetic jack designs.

Because the CRAs are used to control reactivity, and the external housings of the CRDMs form a portion of the reactor coolant pressure boundary, a CRDM pressure housing rupture could lead to a reactivity–initiated accident, and a significant loss–of–coolant accident (LOCA). Small CRDM housing leaks are also possible. A loose or worn CRDM part could cause binding and possibly contribute to an anticipated transient without scram. However, there are a relatively large number of CRDMs on each pressurized water reactor, ranging from 37 for the Fort Calhoun nuclear power plant to 65 for the Maine Yankee plant. Thus, there is redundancy such that if a single CRDM fails to operate properly there is usually no immediate safety concern, though, of course, safety margins are reduced until the problem with the CRDM is rectified.

The reactor internals are designed to support the core, maintain fuel assembly alignment, limit fuel assembly movement, direct the flow of reactor coolant within the reactor vessel, and help shield the reactor vessel from the gamma rays and neutrons emitted by the core. They play a key role in maintaining the geometric integrity of the core and ensuring that its reactivity can be suitably controlled. The major subcomponents of the reactor internals (upper core structure, core shroud/core barrel, thermal shield, and lower core support structure) are shown surrounding the core in Figure 7.1. The reactor internals subcomponents discussed in this chapter do not include the fuel assemblies or CRAs.

There should be no movement of the reactor internals, except for minor flow–induced vibrations and thermal expansions and contractions. Unwanted movement of degraded reactor internals could prevent proper insertion of CRAs, cause loose parts within the reactor coolant system, redistribute flow within the reactor and cause local overheating, or possibly result in fuel element failure and disbursement of fuel within the coolant. Wear on flux thimble tubes can create a potentially non–isolatable leak of reactor coolant.[1]

Sections 7.1.1 through 7.1.5 describe vendor–specific CRDMs. Westinghouse plants contain magnetic jack and roller nut–lead screw CRDMs. Combustion Engineering designs include rack–and–pinion and magnetic jack CRDMs, and Babcock & Wilcox plants are built with roller nut–lead screw CRDMs. Section 7.1.6 describes the reactor internals arrangement for the three PWR vendors according to their vertical location with respect to the core.

7.1.1 Westinghouse Magnetic Jack CRDM Design.[2,3] The Westinghouse design uses a magnetic

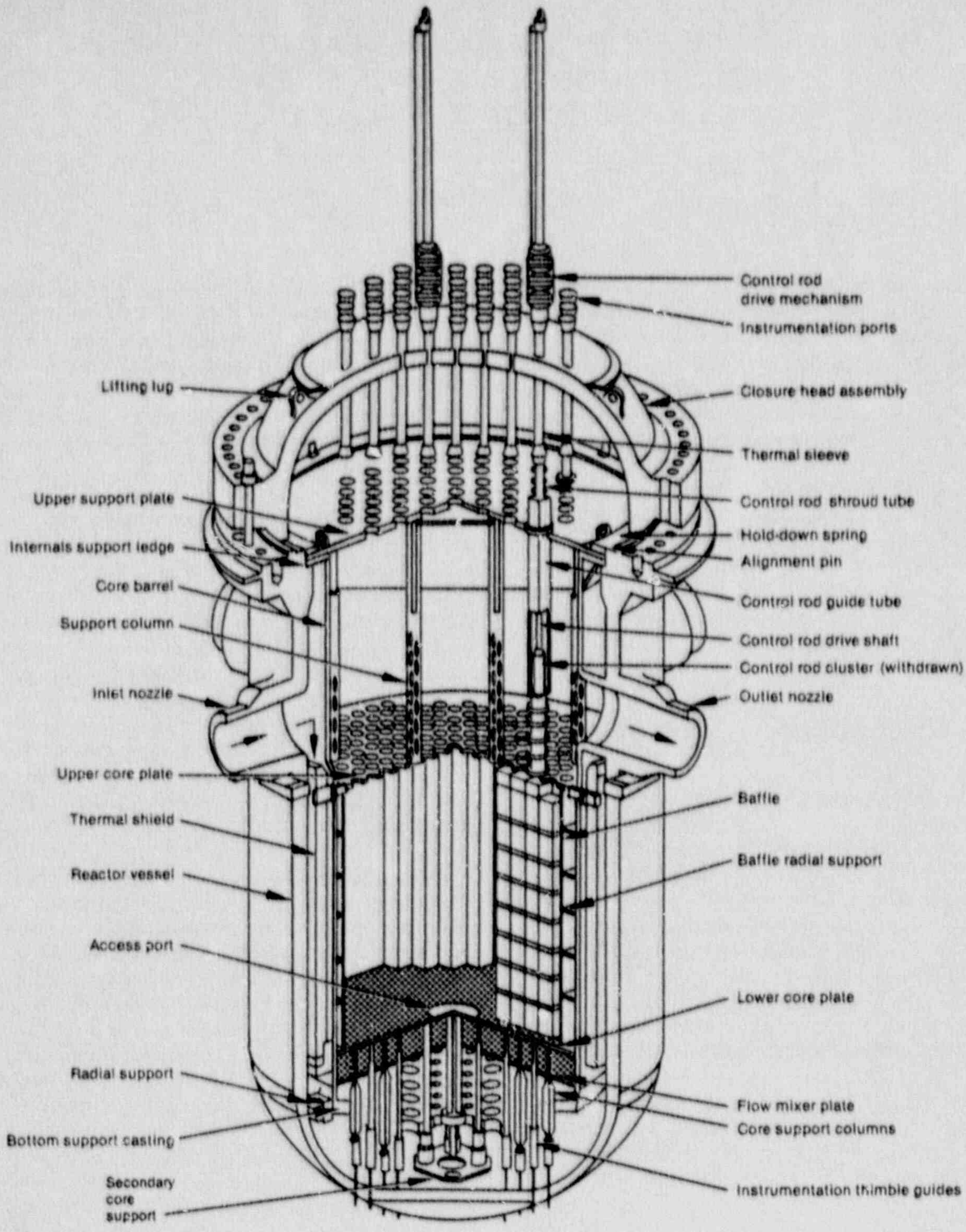


Figure 7.1. Arrangement of Westinghouse CRDM and reactor internals.

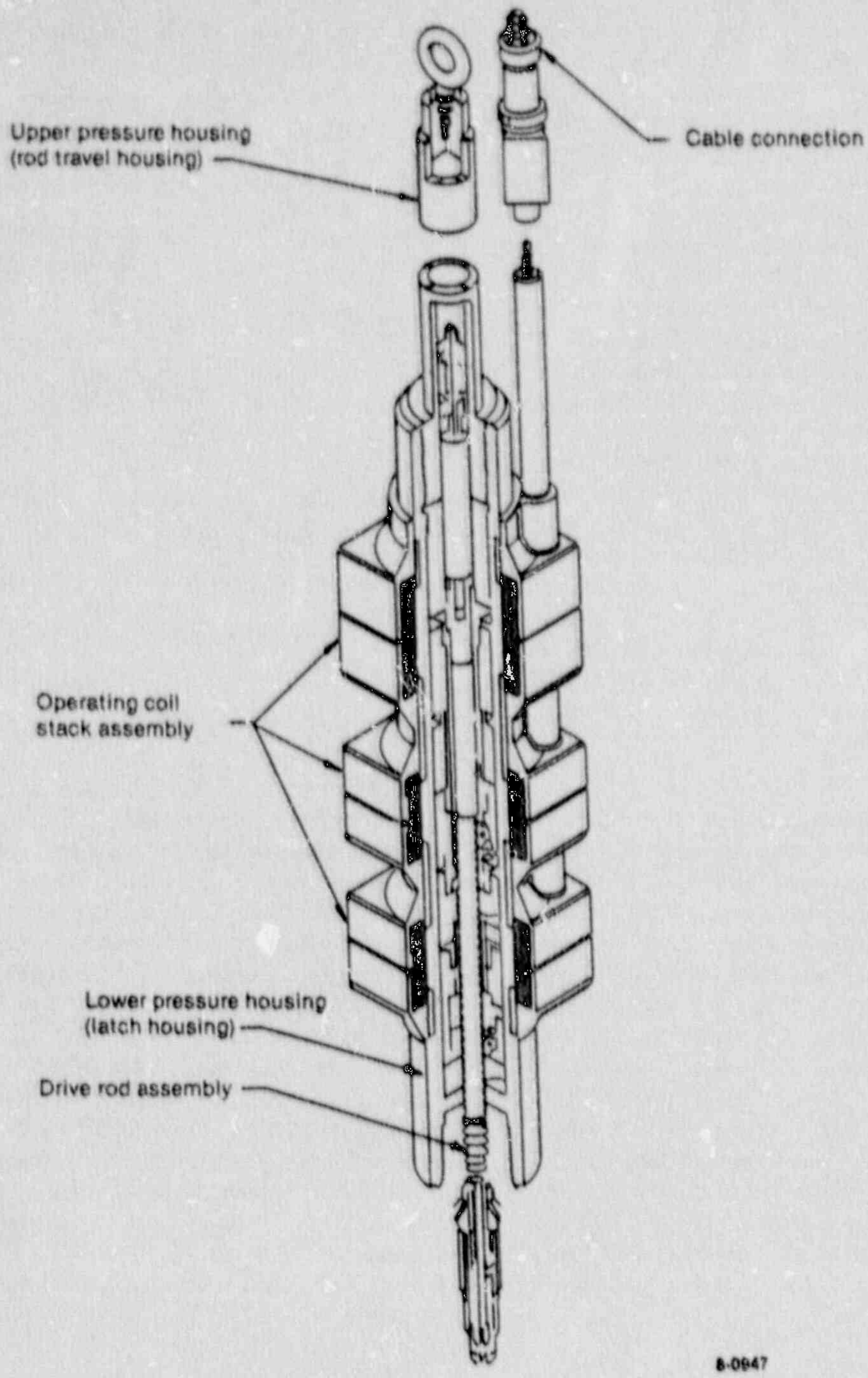


Figure 7.2. Westinghouse magnetic jack CRDM.

jack arrangement for the majority of the CRAs, called full-length rods. The CRDM consists of an internal latch mechanism, a pressure housing, an operating coil stack, a drive shaft assembly, and a rod position indicator coil stack. An overall diagram is shown in Figure 7.2. Each CRDM assembly is an independent unit that can be dismantled or assembled separately. The latch housing is the lower part of the pressure housing and contains the latch assembly. The rod travel housing is the upper portion of the housing and provides space for the drive rod during its upward movement as the control rods are withdrawn from the core. The latch housings are threaded onto adapters on top of the reactor pressure vessel and seal welded. The latch housing and rod travel housing are connected by a threaded, seal-welded maintenance joint.

The operating drive assembly is connected to the CRA by means of a grooved drive shaft. Reactor coolant water fills the pressure-containing part of the CRDM and immerses all moving components. Three magnetic coils, which form a removable electrical unit and surround the pressure housing, induce magnetic flux through the housing wall to operate the working components. They move two sets of latches that lift, lower, and hold the grooved drive shaft. The three magnets are turned on and off in a fixed sequence by solid-state switches. The sequencing of the magnets produces step motion in 16-mm (0.625-in.) increments over the 3.66 m (144 in.) of CRDM travel. The CRDM develops a lifting force approximately twice the static lifting load, providing extra capacity for overcoming mechanical friction. The CRDMs are designed to operate in water at 343°C (650°F) and 17.13 MPa (2485 psi). The electrical coils are air-cooled. The latch assembly minimum operating life without refurbishment or replacement is 2.5 million steps and 400 rod trips.[4] The design life of the drive rod assembly is 5000 full rod withdrawals and insertions, 400 rod trips, and 200 coupling/uncoupling cycles.[4]

All parts exposed to reactor coolant water (such as the pressure housing, latch assembly, and drive rod) are made of corrosion resistant materials: stainless steel, Alloy X-750, and cobalt-based alloys. Wherever magnetic flux is carried by parts exposed to coolant water, 400 series stainless steel is used. For instance, magnetic pole pieces are fabricated from Type 410 stainless steel, which can carry magnetic flux, whereas the nonmagnetic stainless steel parts are fabricated from Type 304 stainless steel, a material that does not carry magnetic flux.[2] Cobalt-based alloys are used for the pins, latch tips, and bearing surfaces. High nickel Alloy X-750 is used for the springs of both latch assemblies, and Type 304 stainless steel is used for all pressure-containing parts. Most pressure housings are wrought; however, some are cast.[5] Some of the materials used are listed in Table 7.1.

The magnetic jack CRDMs, shown in more detail in Figure 7.3, withdraw and insert their respective CRAs as electrical pulses are received by the operator coils. An on-and-off sequence, repeated by switches in the power programmer causes either withdrawal or insertion of the CRA. A typical lift step proceeds as follows. The movable gripper is energized, which lifts the movable gripper armature to the closed position shown in Figure 7.3. This forces the movable latch to engage the drive rod and compresses the movable armature return spring. Next, the stationary gripper coil is deenergized, the stationary armature return spring moves the stationary gripper armature downward, and the stationary latch opens. Next, the lift coil is energized, the lift armature along with the drive rod is moved up one step [which is 16 mm (0.625 in.)], and the lift return spring is compressed. The stationary gripper coil is then energized again, which lifts the stationary gripper armature, engages the stationary latch (shown open in Figure 7.3), and holds the drive rod immovable. Finally, the movable gripper and lift coils are deenergized and the springs return the movable gripper and lift armatures to their original (down) positions and the movable latch to the open position. The cycle can then start over or the stationary gripper coil can continue to hold the CRA at a given position. When power to the movable gripper coil is interrupted, the rod is scrammed, since the combined weight of the drive shaft and CRA is sufficient to move the latches out of the shaft groove, and the CRA falls by gravity into the core.

Table 7.1. Materials Used in Westinghouse CRDMs[2]

Location	Material
Magnetic pole pieces	Type 410 stainless steel
Pressure housing	Type 304 stainless steel or CF-8 stainless steel
Link pins; locking button	Haynes 25
Springs	Alloy X-750
Latch arm tips	Clad with Stellite 6
Bearing and wear surfaces	Stellite 6 and hard chrome plate
Cast coil housings	Zinc-plated ductile iron
Drive shaft assembly	Type 410 stainless steel
Other	Type 304 stainless steel

7.1.2 Westinghouse Roller Nut-Lead Screw Design.[3] Westinghouse also uses part-length CRAs, which are positioned by roller nut-lead screw CRDMs very similar to the Babcock & Wilcox CRDMs (described in more detail in Section 7.1.5). Five rotating roller nuts grip the lead screw, and as sequential pulses are applied to the armature the CRA is raised or lowered. The CRAs can be inserted into the core to control the axial power distribution, such as occurs during xenon-induced power oscillations. No scram by release and free fall of the CRA is provided for.

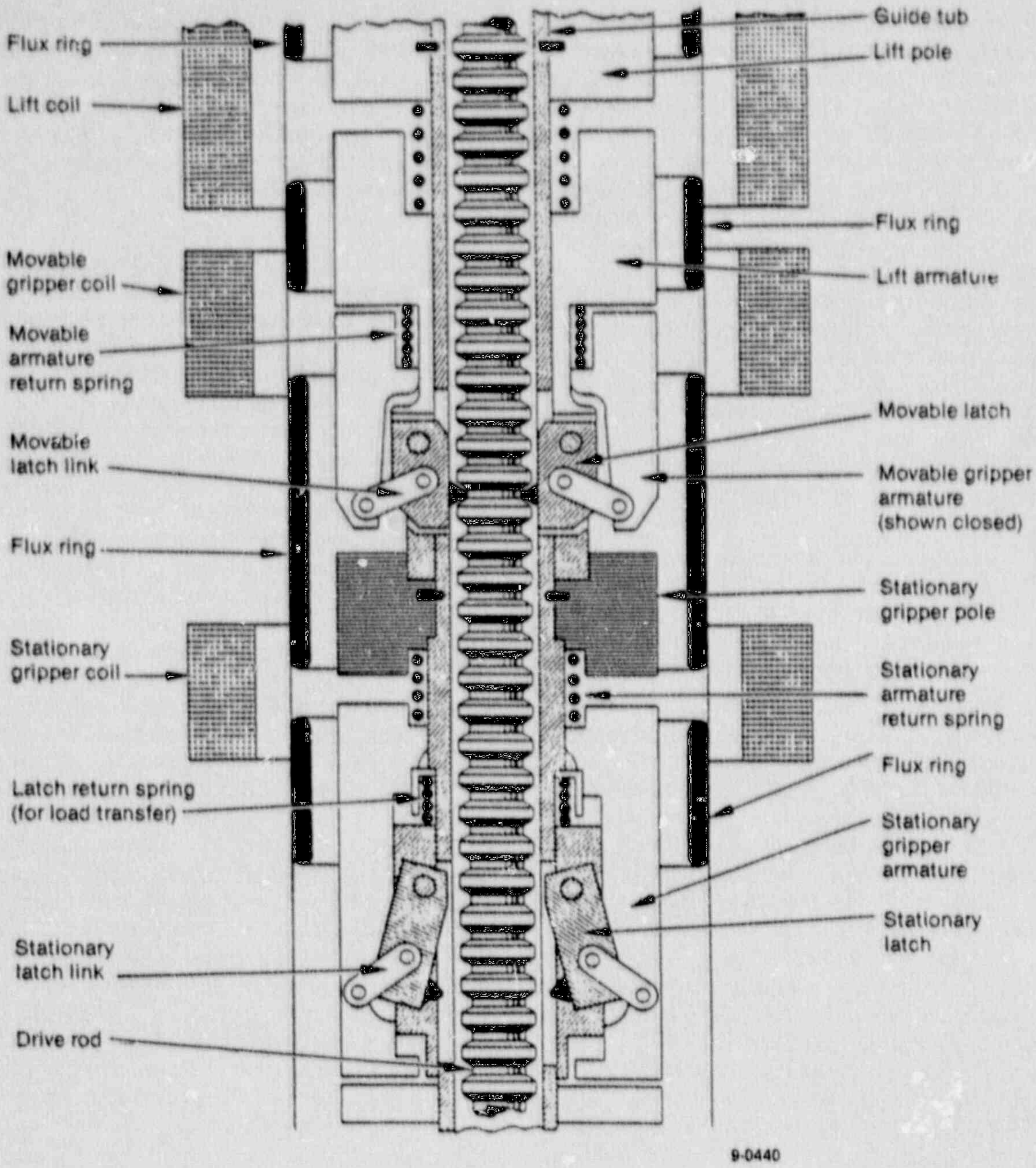


Figure 7.3. Details of Westinghouse magnetic jack CRDM.

It is possible to remove the cooling air shroud, the position indicating coils, and the motor stator for maintenance from the pressure housing without removing the pressure housing from the head adapter. This can be accomplished with the reactor head in position on the reactor.

7.1.3 Combustion Engineering Magnetic Jack CRDM Design.[6,7] A magnetic jack CRDM was used in the Maine Yankee design (as well as in all Combustion Engineering designs, with the exception of Fort Calhoun and Palisades, which have rack-and-pinion designs) and has also been adopted for the standard Combustion Engineering CESSAR design. Each CRDM is capable of withdrawing, inserting, holding, or tripping a CRA from any point within its full stroke. Some of the CRAs are not required to undergo scrams, however, and consequently their CRDMs are modified to prevent tripping upon loss of power. The CRDMs are mounted on flanged nozzles on top of the reactor vessel, which supports the CRDM's weight. The general design features of the CRDM are shown in Figure 7.4.

The pressure housing consists of the motor housing assembly and the upper pressure housing assembly. The motor housing assembly, shown in Figure 7.4, is attached to the reactor vessel head nozzle by means of a threaded joint, and is seal welded. Once the motor housing has been seal welded to the reactor vessel head nozzle, it need not be removed, since all servicing of the CRDM is performed from the top of the upper housing. This opening is closed by means of a threaded cap and an omega seal weld. The omega seal is shaped like the capital Greek letter Ω, and is relatively flexible, so that it can withstand a limited amount of differential movement. It does not resist mechanical loads or the pressure loads from the entire CRDM, but is designed to resist the local pressure load within the seal area. The omega seal, if undegraded, is a continuous solid metal pressure boundary having no leak path such as occurs with gaskets.

The housing design and fabrication conform to the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code)[8] for Class A vessels. It is designed for steady-state conditions, as well as all anticipated pressure and thermal transients.

The magnetic jack assembly is an integral unit that fits into the pressure housing through an opening in the top of the housing. The lifting operation consists of a series of magnetically operated step movements similar to the movements described above in the Westinghouse units. Two sets of mechanical latches engage a notched extension shaft. The magnetic force is obtained from large dc magnet coils mounted on the outside of the lower pressure housing. The CRDMs are forced-air cooled. A control programmer actuates the stepping cycle and obtains the CRA location by a forward or reverse stepping sequence. CRDM hold is obtained by energizing one coil at a reduced current while all other coils are deenergized. The scrammable CRAs are tripped upon interruption of electrical power to all coils. One set of latches is modified in the CRDMs that drive part-length CRAs to prevent lowering the rods without electromagnetic actuation. Eight of the 65 CRDMs in the Maine Yankee Plant are non-scrammable and are connected to part-length CRAs.[6]

The CRA is connected to the drive shaft extension with an internal collet-type coupling at its lower end. Coupling is performed before the reactor vessel head is installed. Whenever the upper guide structure is removed from the vessel, the drive shafts (uncoupled from the CRAs) are removed also.

7.1.4 Combustion Engineering Rack-and-Pinion CRDM Design.[9] This type of CRDM is used at the Fort Calhoun and Palisades plants. The CRDMs are mounted on flanged nozzles on top of the reactor vessel closure head, located directly over the CRAs in the reactor core. Each CRDM is connected to a CRA by a locked coupling. The weight of the CRDM is supported by the reactor vessel head. The electrical components are air-cooled.

The vertical rack-and-pinion CRDM has the drive shaft running parallel to the rack, and drives the pinion gear through a set of bevel gears. The basic design is shown in Figure 7.5. The rack is driven by an electric motor operating through a gear reducer and a magnetic clutch. The CRA drops into the reactor under the influence of gravity when the magnetic clutch is deenergized. The magnetic clutch incorporates an anti-reversing device that prevents upward CRA movement when the clutch is deenergized. For those CRAs that maintain their positions during a reactor trip (called part-length CRAs), the CRDMs are modified by replacing the magnetic clutch with a solid shaft assembly, which eliminates the trip function. Otherwise, this type of CRDM is the same as the others. The drive shaft penetration through the pressure housing is closed by means of a face-type rotating seal. The rack is connected to the CRA by means of a rack extension containing an external collet-type coupling that expands and locks into a mating shouldered bore on top of the CRA. The rack extension is connected to the rack through a tie bolt by means of a nut and locking device at the upper end of the rack. A small-diameter closure located at the top of the pressure housing provides tool access to this nut for releasing the CRA from the CRDM. The rack is guided at its upper end by a section having an enlarged diameter that operates in a tube extending the full length of the CRA travel. The final cushioning at the end of a CRA drop is provided by the dashpot action of the enlarged diameter of the rack entering a reduced diameter in the guide tube.

The pressure housing consists of a lower and an upper section joined near the top of the CRDM by means of a threaded autoclave-type closure. The lower housing is a stainless steel tubular section welded to an eccentric reducer and flange piece at the lower end. This flange piece fits the nozzle flange on the reactor vessel closure head and is seal welded to it by an omega- or canopy-type seal. Once seal welded and bolted into place, the lower pressure housing need not be removed, since all servicing of the CRDM is performed from the top of this housing. The upper part of the lower housing is machined to form the autoclave-type closure and is provided with a recessed gasket surface for a spirally wound gasket.

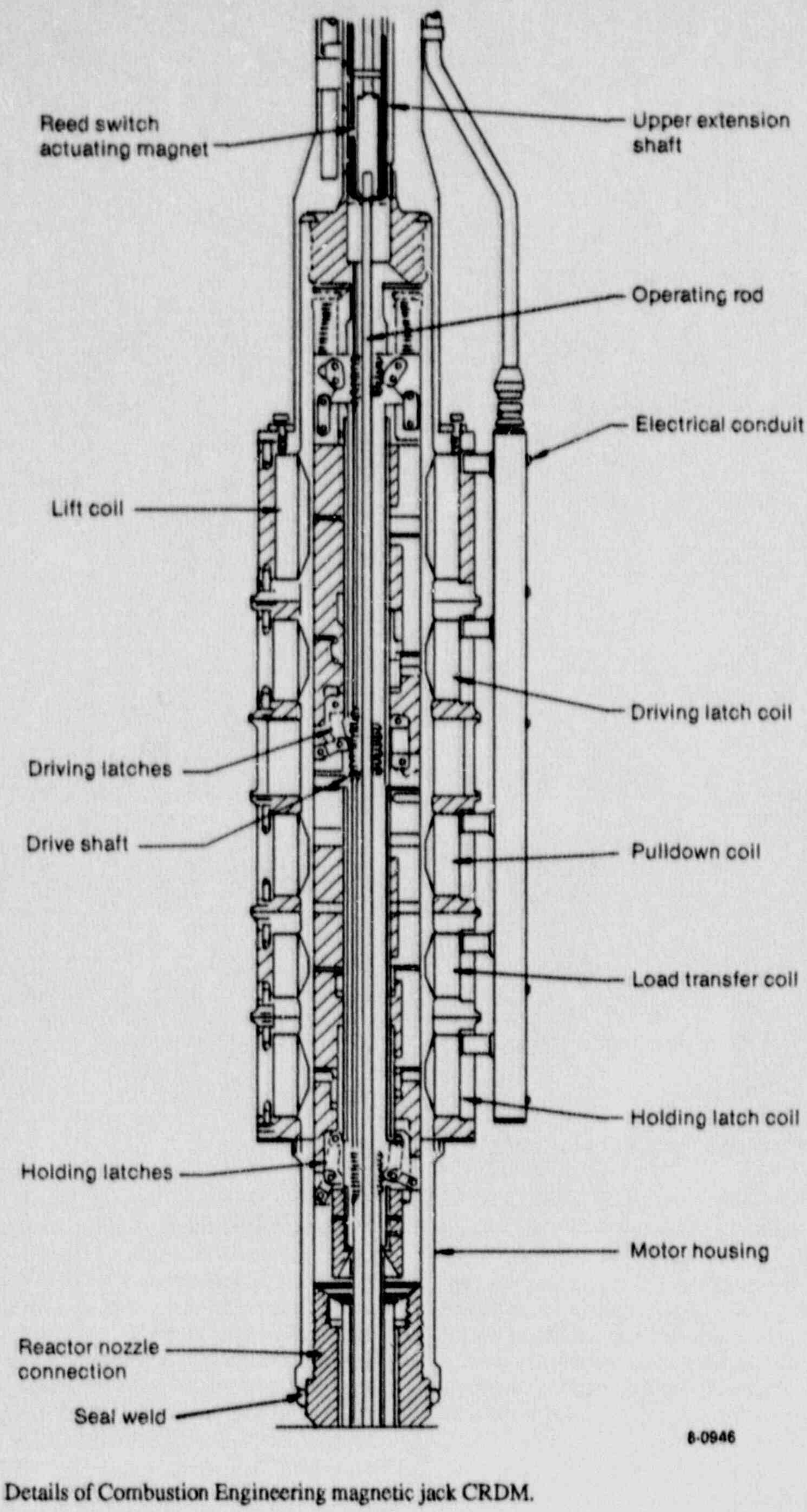


Figure 7.4. Details of Combustion Engineering magnetic jack CRDM.

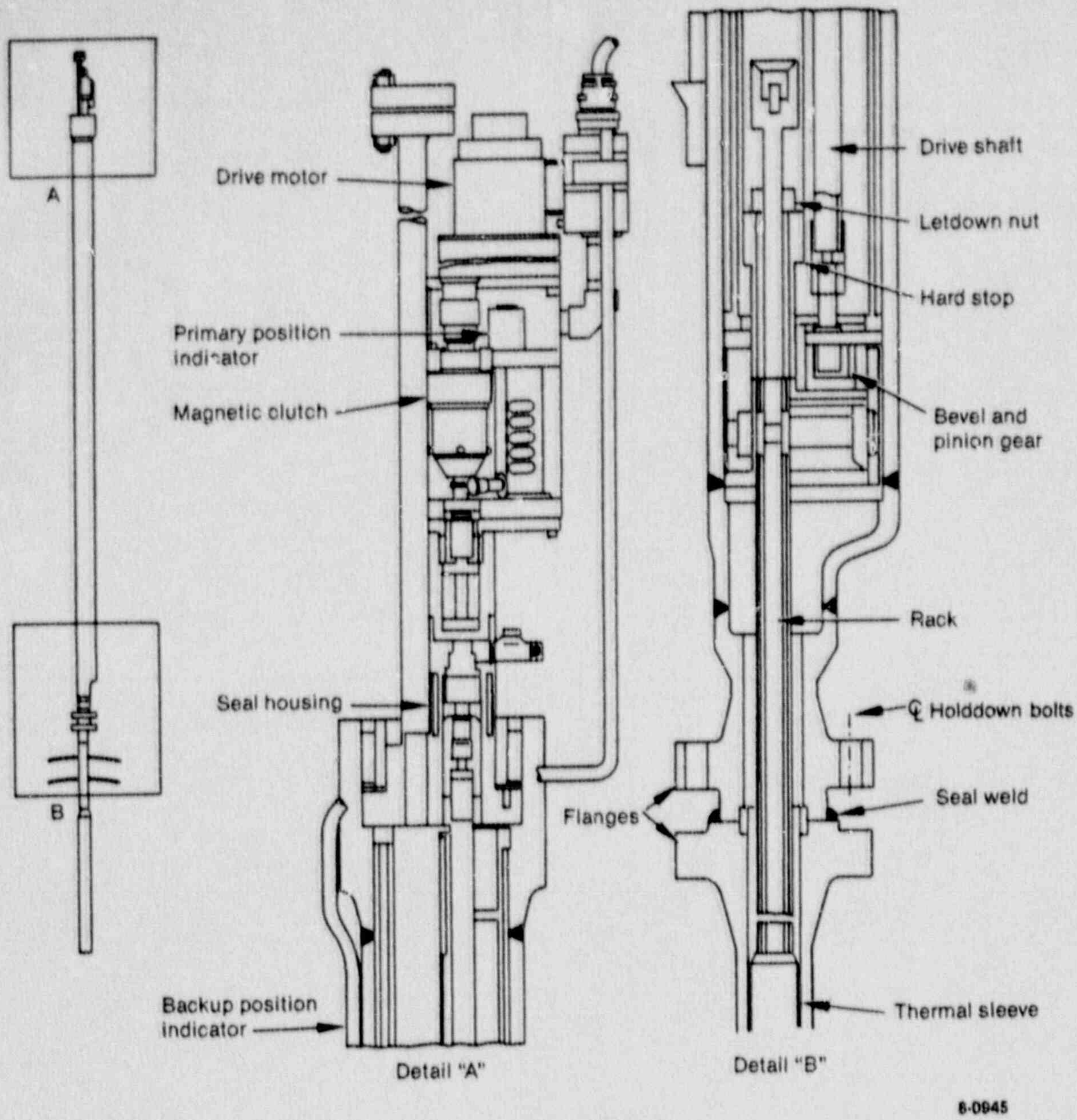


Figure 7.5. Details of Combustion Engineering rack–and–pinion CRDM.

The upper part of the pressure housing has a flange that mates with the lower housing autoclave–type closure, a cavity that contains the drive rotating seal, and a tubular housing extension with a small flange closure that provides access for attaching and detaching the CRA. A cooling jacket surrounds the seal area to maintain lower temperatures of the seal and system. It is under low pressure and is not connected to the reactor coolant system.

The rack–and–pinion assembly is an integrated unit that fits into the lower pressure housing and couples to the motor drive package through the upper pressure housing. This subcomponent carries the bevel gears that transmit torque from the vertical drive shaft to the pinion gear. The vertical drive shaft has splined couplings at both ends and may be lifted out when the upper pressure housing is removed. The bevel and pinion gears are supported by ball bearings. The gear assembly is attached t^ a stainless steel tube supported by the upper part of the pressure housing. The rack is a tube with gear teeth on one side of its outer surface and is flat on the opposite side, forming a contact surface for guide rollers. The upper end of the rack is fitted with an enlarged section that runs in the guide tube and provides lateral support for the upper end of the rack.

Power to operate the CRDM is supplied by a fractional horsepower, single-phase, 60-Hz motor. This entire drive package can be removed as a unit without disturbing other parts of the CRDM. The electrical connections are located at the top of the CRDM and are readily accessible.

The CRA is connected to the CRDM by means of an extension shaft with an internal collet-type coupling at its lower end. A tie rod connects the extension shaft to the rack. In order to disengage the CRA, the flange access closure at the top of the CRDM is removed.

7.1.5 Babcock & Wilcox CRDM Design.[10,11] All Babcock & Wilcox CRDMs are of the roller nut-lead screw design. The Babcock & Wilcox reactor also has two types of CRDMs, the shim safety drive mechanism and the axial power shaping rod drive. They are identical, with the exception that in the axial power shaping rod drive the roller nut assembly will not disengage from the lead screw on loss of power to the stator, and thus the axial power shaping rods do not have fast insertion capability. A differentiation between the two drives will not be made hereafter.

The Babock & Wilcox CRDM consists of a motor tube (the external pressure housing) that houses a lead screw and its rotor assembly, and a buffer. The top end of the motor tube is closed by a closure and vent assembly. An external motor stator surrounds the motor tube, and position indicator switches are arranged outside the motor tube extension.

The rotor assembly consists of a ball-bearing-supported rotor tube carrying a pair of scissor arms. When current is impressed on the stator, located outside the pressure boundary, the upper halves of the scissor arms are magnetically pulled radially outward toward the motor tube wall. The scissor arms are pivoted in the rotor tube, and as they are moved outward, four roller nuts on the lower part of the arms (two on each arm) are thereby forced radially inward to engage the centrally located lead screw. The ball-bearing-supported roller nut assemblies are skewed at the lead screw helix angle for engagement with the lead screw. When the three-phase rotating magnetic field is applied to the motor stator, the resulting magnetic force produces rotor assembly rotation. The roller nuts mounted on the scissor arms rotate around the lead screw, which is coupled to the CRA through a bayonet coupling. As the magnetic force rotates the rotor assembly, the non-rotating lead screw translates upward or downward (depending on the direction of rotor rotation).

Four springs mounted in the scissor arms keep the rollers disengaged when the power is removed from the stator coils. For rapid insertion (shim safety drive mechanisms), the nut halves separate to release the screw and the CRA, which drop into the core by gravity. A hydraulic buffer assembly within the upper housing decelerates the moving CRA to a low speed a short distance above the CRA full-in position. The final CRA deceleration energy is absorbed by the down-stop buffer spring.

The motor tube (pressure housing) is a three-piece welded assembly designed and manufactured in accordance with the requirements of the ASME Code[8] for a Class A nuclear pressure vessel (for the 1968 and previous Codes, the designation was Class A; for the 1971 and subsequent Codes, vessels were designated as Class 1). The motor tube forms the CRDM pressure boundary for the reactor coolant. Materials conform to ASTM or ASME Code, Section II, material specifications. The motor tube wall between the rotor assembly (inside the motor tube) and the stator (located outside the motor tube) is constructed of magnetic material (Type 403 stainless steel) to present a small air gap to the motor. The upper end of the motor tube functions only as a pressurized enclosure for the withdrawn lead screw. This section of the motor tube is made of Type 304 stainless steel, and is welded to the upper end of the Type 403 stainless steel motor section. The lower end is welded to a stainless steel machined forging that contacts the control rod nozzle by means of flanged faces. Double gaskets, separated by a ported test annulus, seal the flanged connection between the motor tube and the reactor vessel. The upper end of the motor tube is closed by a closure insert assembly containing a vapor bleed port and vent valve. The vent valve and insert closure have double seals.

The motor includes a slip-on stator that operates in a pulse-stepping mode, advancing 15 degrees per step. The stator has water cooling coils wound on the outside of its casing, and is encapsulated after winding to establish a sealed unit.

7.1.6 Reactor Internals. The discussion describing the reactor internals will be divided into three parts, covering the subcomponents above, surrounding, and below the core. Some subcomponents are joined by welding, whereas others are connected by stainless steel or Alloy X-750 bolts, screws, or pins. Overall views of the three vendors' (Westinghouse, Combustion Engineering, and Babcock & Wilcox) designs are shown in Figures 7.1, 7.6, and 7.7. Figure 7.8 shows how the various subcomponents fit together to form the Babcock & Wilcox reactor internals assembly. All major components are made of Type 304 stainless steel. The Westinghouse and Combustion Engineering reactor internals materials are listed in Table 7.2. The upper core support structure is located above the core, and for each of the three designs can be installed and removed during refueling as a unit. The reactor internals are generally designed and analyzed in accordance with the intent of Subsection NG of the ASME Code.[8] However, the majority of operating plants were designed before Subsection NG existed.

Upper Core Structure. The Westinghouse upper core support structure, shown in Figure 7.1, consists of the upper support plate and the upper core plate, between which are contained support columns and guide tube assemblies. In some Westinghouse plants, deep beam sections are located directly under the upper support plate. The outer edge of the upper support plate and core barrel rest on the internals support ledge of the reactor pressure vessel. The mechanical loads are transmitted between these subcomponents through bolt-like connections called fasteners, rather than through welds. The support columns establish the spacing between the upper support structure and the upper core plate. The columns are fastened at their tops and bottoms to the plates, and transmit mechanical loadings between the plates. The guide tube assemblies sheath and guide the CRDM shafts and CRAs. They are fastened to the upper support plate and are guided by support pins (also called split pins) in the upper core plate. The control rod shroud tube, which is fastened to the upper support plate and guide tube, provides additional guidance for the CRDM shafts.

The Combustion Engineering design is shown in Figure 7.6. The upper end of the assembly consists of a support plate welded to a grid array of deep beams and a deep cylinder that encloses and is welded to the ends of the beams. The grid aligns and supports the upper end of the CRA shrouds. The shrouds consist of centrifugally cast CF-8 stainless steel cylindrical upper sections welded to integral bottom sections, which are shaped to provide flow passages for the coolant while shrouding the CRAs from crossflow. The shrouds are bolted to the fuel assembly alignment plate. Single shrouds are connected to the plate by spanner nuts; dual-type shrouds are attached to the upper plate by welds.

The Babcock & Wilcox design is called the plenum assembly and is shown in Figure 7.7. It consists of a plenum cover, upper grid, CRA guide tubes, and a flanged plenum cylinder with openings for reactor coolant outlet flow. The plenum cover is constructed of a series of parallel flat plates intersecting to form square lattices; it has a perforated top plate, and an integral flange at its periphery. The cover assembly is attached to the plenum cylinder top flange. The CRA guide tubes are welded to the plenum cover top plate and bolted to the upper grid. Each guide tube assembly consists of an outer housing, a mounting flange, perforated slotted tubes, and four sets of tube segments oriented and attached to a series of castings. The plenum cylinder consists of a large cylindrical section with flanges on both ends to connect the cylinder to the plenum cover and the upper grid. Holes in the plenum cylinder provide a flow path for reactor coolant. The upper grid consists of a perforated plate bolted to the plenum cylinder lower flange.

Core Shroud/Core Barrel/Thermal Shield. The core is surrounded by a core shroud (also called formers and baffles) that is enclosed by a core barrel. Proceeding radially outward, the core barrel is in turn surrounded by a cylindrical thermal shield, with the entire assembly contained within the reactor vessel. Figure 7.9 shows the radial orientation of these components.

The former and baffle plates are attached to the core barrel wall and form the enclosure periphery of the assembled core. They limit the amount of coolant bypass flow. The 44.5- to 63.5-mm- (1.75- to 2.5-in.-) thick core barrel supports the fuel assemblies and the lower reactor internals. It is a flanged cylinder. In the Babcock & Wilcox design, the upper flange is bolted to the core support shield (which rests on a ledge of the reactor vessel inner wall), and the lower flange is bolted to the lower reactor internals. On the Westinghouse and Combustion Engineering designs, the core barrel rests directly on the ledge and is welded to the lower reactor internals.

The 51- to 76-mm- (2-to-3 in.-) thick thermal shield is fixed to the core barrel at the top with rigid, bolted connections (Westinghouse), and is positioned by pins (Combustion Engineering) or spacers (Babcock & Wilcox) to minimize flow-induced vibrations. The thermal shield has been removed from many of the Combustion Engineering-designed plants as a result of flow-induced vibration problems, and is, therefore, not shown in Figure 7.6. The bottom is connected to the core barrel by means of an axial flexure in the Westinghouse design, and to the lower grid support in the Babcock & Wilcox design. Its purpose is (a) to reduce the internal heat generation caused by incident gamma absorption in the reactor vessel wall, and

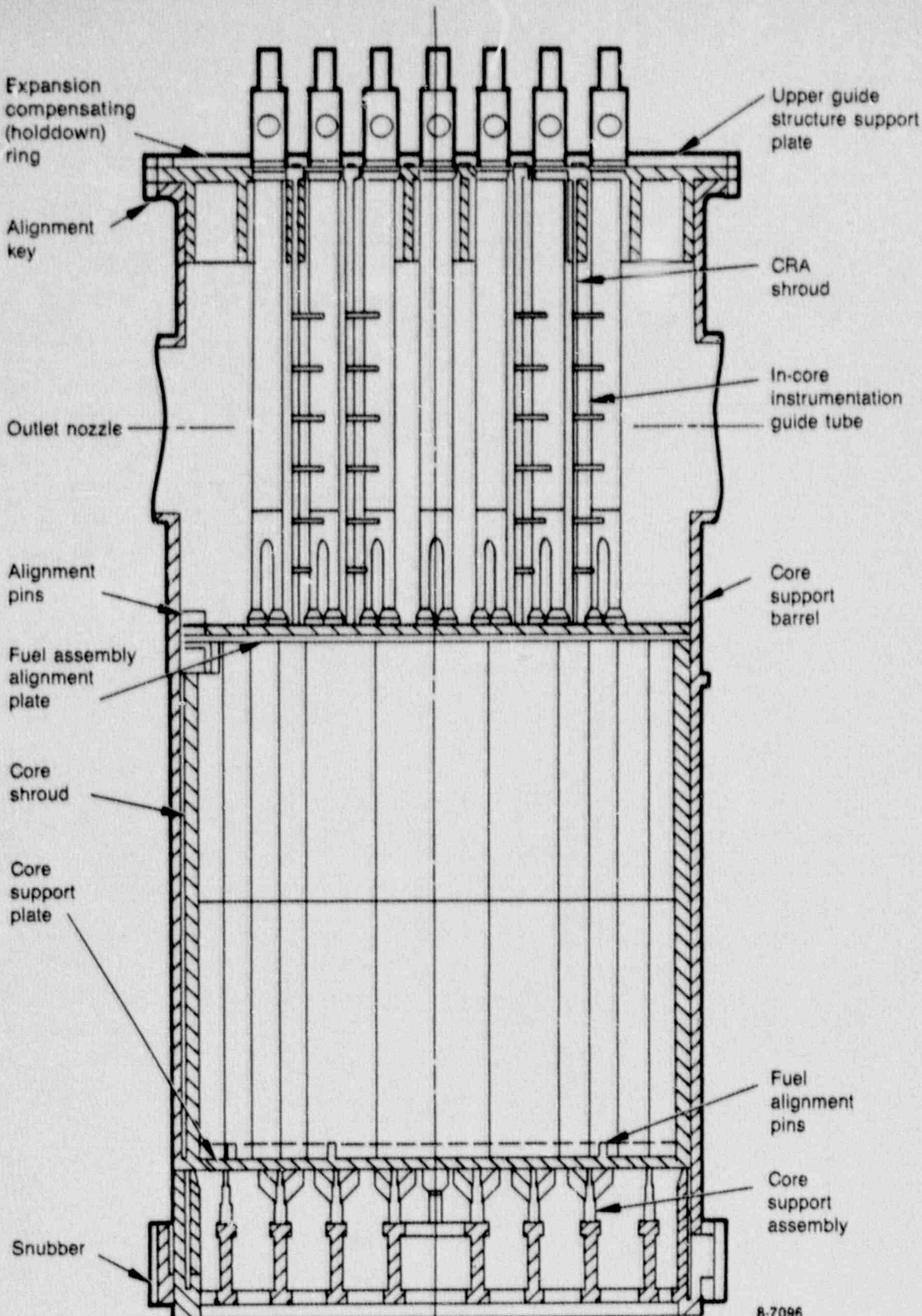


Figure 7.6. Combustion Engineering reactor internals.

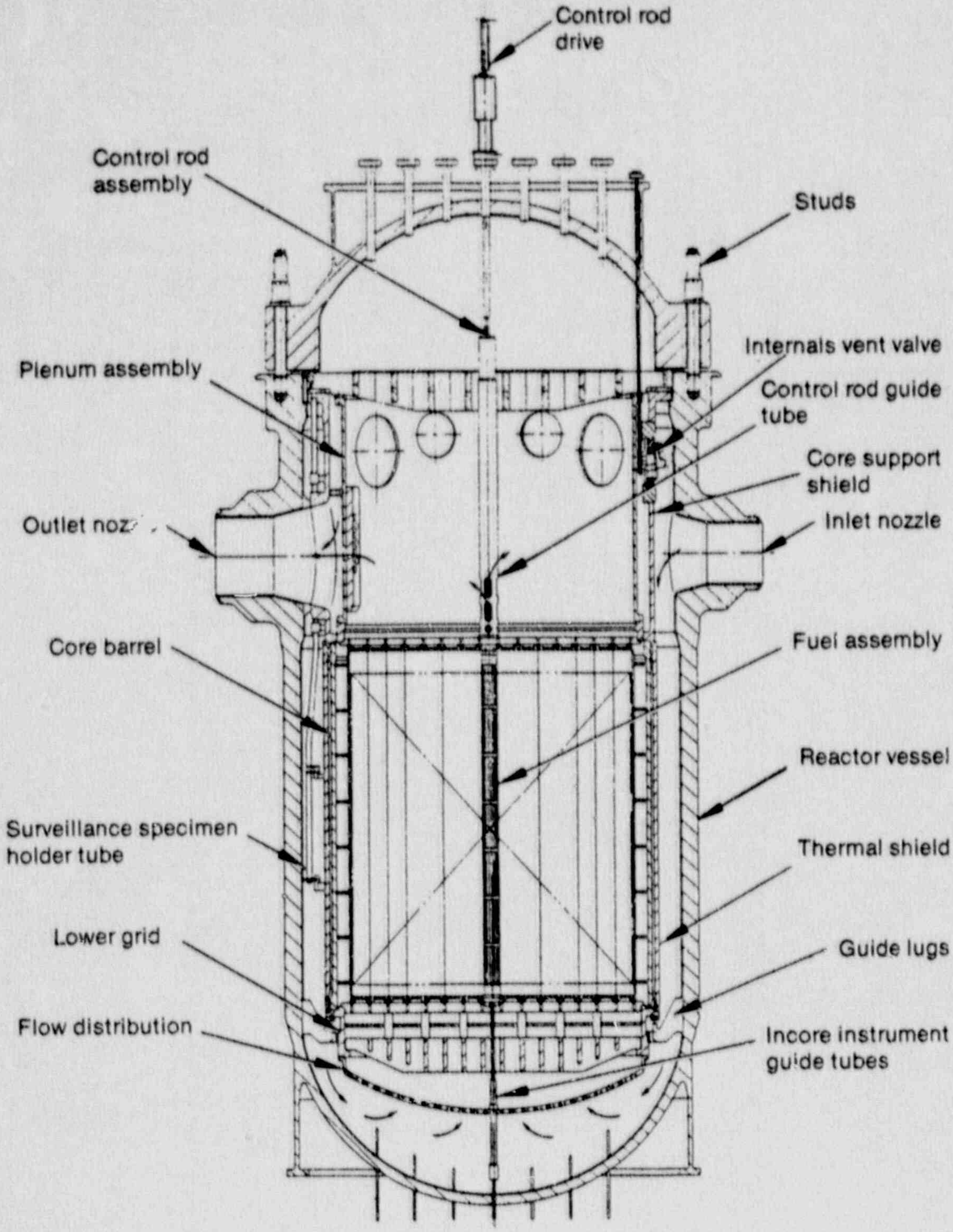


Figure 7.7. Babcock & Wilcox reactor internals.

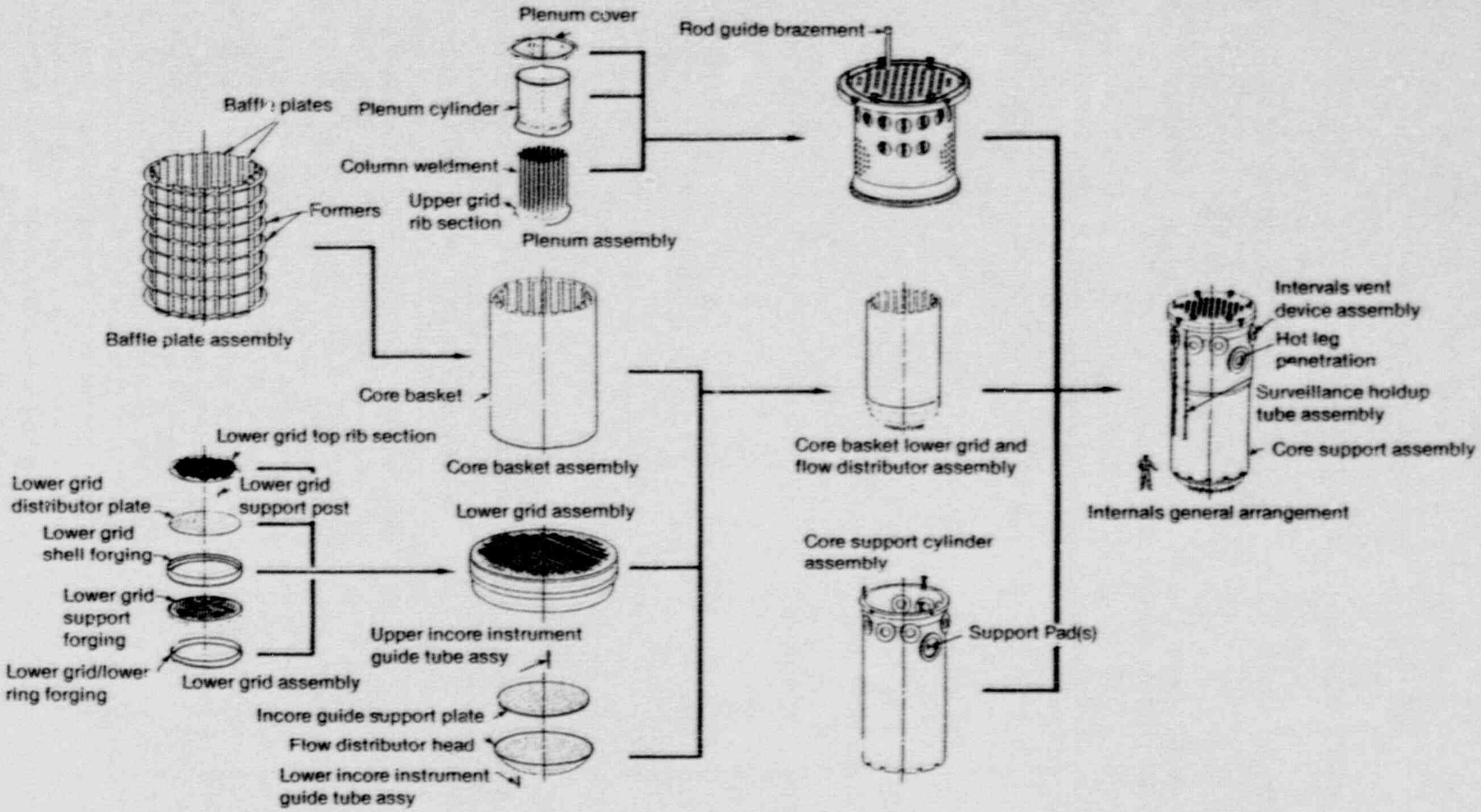


Figure 7.8. Arrangement of Babcock & Wilcox reactor internals.

Table 7.2. Materials used in Westinghouse and Combustion Engineering reactor internals

Westinghouse		Combustion Engineering	
Subcomponent	Material	Subcomponent	Material
Core barrel, thermal shield, shroud, formers and baffles	Type 304 stainless steel	Core barrel assembly	Type 304 stainless steel; Alloy A-286
Upper support structure	Type 304 stainless steel	Upper guide structure assembly	Type 304 stainless steel; Grade CF-8 cast stainless steel; Alloy A-286
Lower support structure	Type 304 stainless steel; Grade CF-8 cast stainless steel[a]	Core shroud assembly	Type 304 stainless steel
Flux thimbles	Type 304 cold-worked stainless steel	Holddown ring	Type 304 stainless steel
Split pins	Alloy X-750	Bolts and pins	Alloy A-286 and Type 316 stainless steel
Bolts and dowel pins	Type 316 stainless steel	Wear surfaces	Chrome plating; Stellite 25 hardfacing
Flow mixer	CF-8 stainless steel[a]	Flow skirt	Ni-Cr-Fe
Cruciform instrument guides	CF-8 stainless steel[a]		
Hold-down spring	Type 403 stainless steel		
Radial support key bolts	Alloy X-750		
Radial support clevis inserts	Alloy 600		

a. Some early designs.

thereby reduce thermal stresses, and (b) to reduce neutron impingement on and embrittlement of the vessel wall.

The core barrels and thermal shields are very long cylinders and, therefore, are subject to flow-induced oscillatory forces. The Combustion Engineering core barrels are 8.2-m (27-ft) long and supported only at their upper end, where they rest on a ledge on the inside of the reactor vessel. Therefore, amplitude limiting devices called snubbers are located near their lower end between the core barrel and the reactor vessel.

Troubles with the very early Westinghouse thermal shield designs led to the use of a one-piece thermal shield in most Westinghouse plants that is rigidly attached to the core barrel at one end and flexured at the other. The early designs that malfunctioned were multipieced thermal shields that rested on vessel lugs and were not rigidly attached at the top. Early core barrel designs that have malfunctioned in service employed tie rods joining the bottom support to the bottom of the core barrel, and a bolted connection that tied the lower core barrel to the upper core barrel. The malfunctions are believed to have been caused by the use (in a few early plants) of bolts with a thermal expansion coefficient less than the flange material and oscillations of the thermal shield, creating forces on the core barrel. Other forces were induced by unbalanced flow in the lower plenum of the reactor. Corrective modifications had been made by the time of the Zion Westinghouse design, and comparatively few problems have been experienced with the redesigned internals. The most recent Westinghouse plants use local neutron shield panels attached directly to the outside of the core barrel instead of thermal shields to limit the neutron fluence (see Figure 7.10).

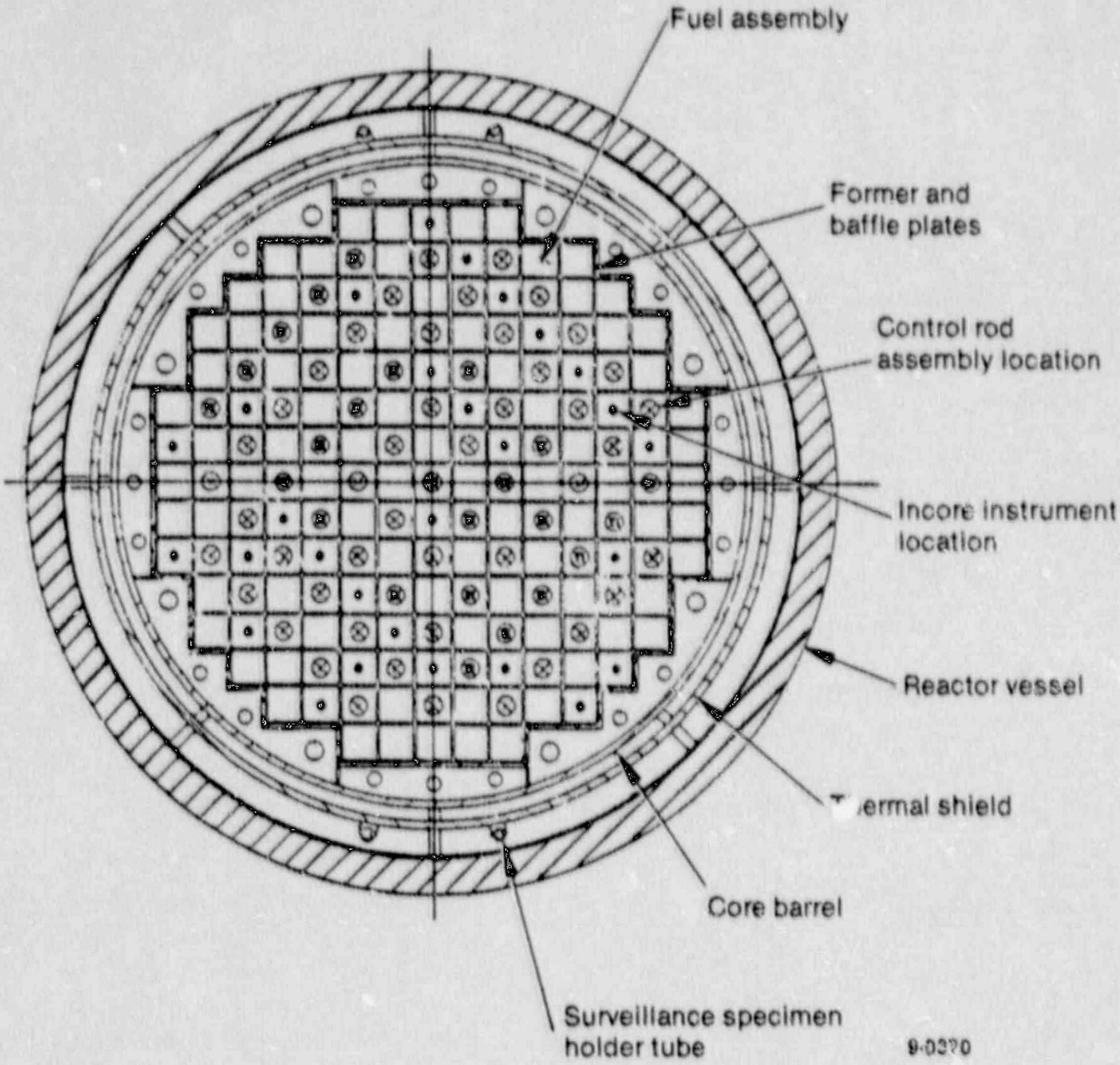


Figure 7.9. Radial orientation of Babcock & Wilcox reactor internals.

Lower Core Support Structure. The lower core support plate of the Westinghouse and Combustion Engineering designs is positioned at the bottom level of the core below the baffle plates, and provides support and orientation for the fuel assemblies. The plate is a 51-mm- (2-in.-) thick perforated member that distributes coolant flow to the individual fuel assemblies as required. The core load is transmitted through this plate to a thick bottom support plate. In some early Westinghouse designs, this dished plate was made of cast stainless steel (CF-8), as were some early flow mixer plates and cruiciform instrument guides. The plate is laterally supported by a cast, Alloy 600 radial support, which is welded to the reactor vessel. A secondary core support is located under the bottom support to limit the core drop in the event of a severe accident.

The lower support in the Babcock & Wilcox design (Figure 7.7) consists of two grid structures separated by short tubular columns, and surrounded by a forged flanged cylinder. The upper structure is a perforated plate, whereas the lower structure consists of a 254-mm- (10-in.-) thick machined forging. The top flange of the forged cylinder is bolted to the lower flange of the core barrel. A perforated 51-mm- (2-in.-) thick dished head (flow distributor) with an external flange is bolted to the bottom flange of the lower grid.

Other Internals. There are a number of other smaller reactor internals subcomponents included in each design. Some of these are surveillance specimen holder tubes, in-core instrument (such as flux thimbles and thermocouples) guide tubes and their supports,

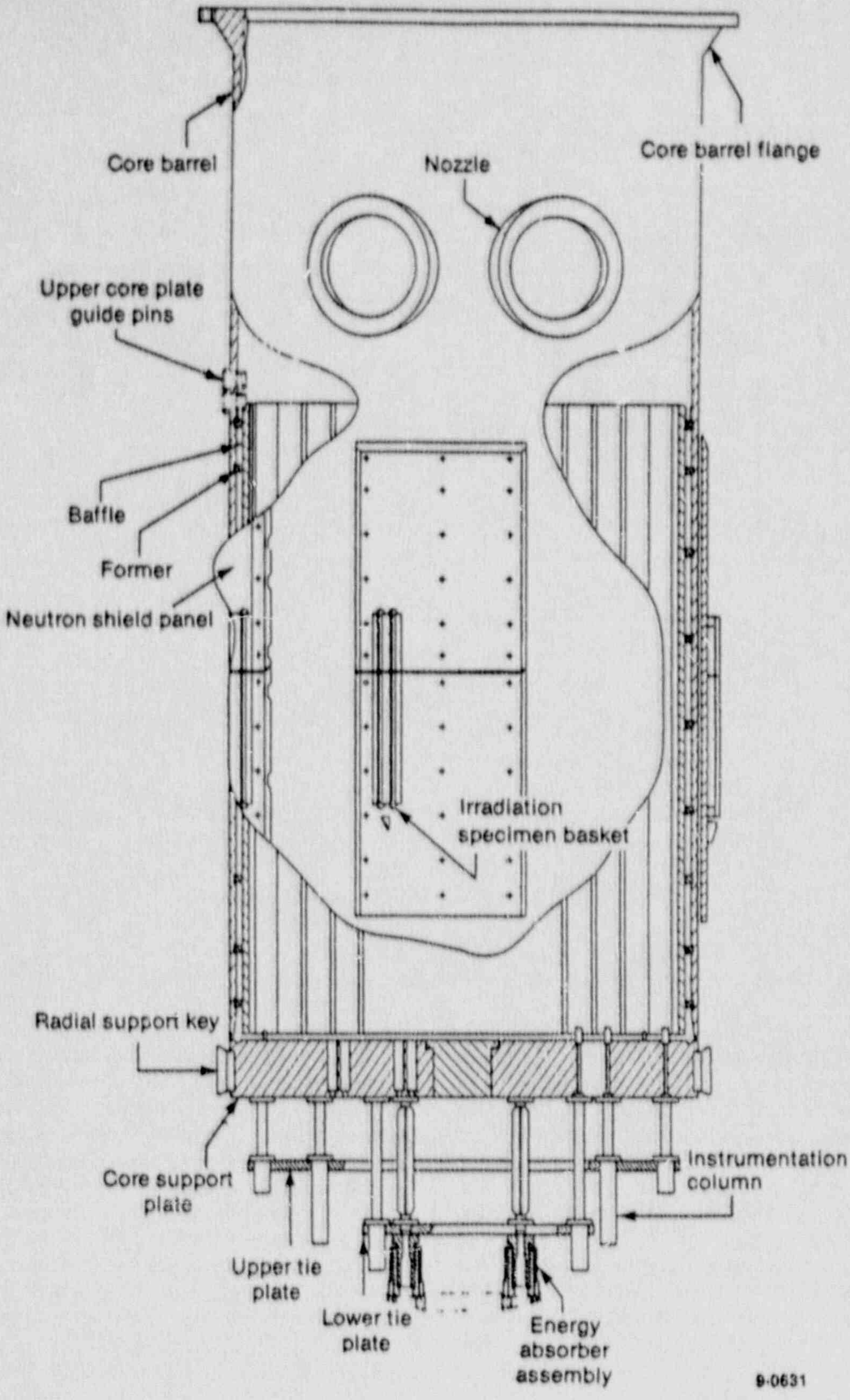


Figure 7.10. Westinghouse lower core support assembly showing position of neutron shield panel.

internals vent valves, and control rod guide thimbles. Some of these are particularly susceptible to degradation. For instance, in the Westinghouse reactors thin sealed stainless steel conduits that enter the reactor vessel through the upper head are used to route core thermocouples. There are also bottom port columns in the reactor vessel that carry retractable, cold worked stainless steel flux thimbles that are pushed upward into the reactor core. The thimbles are closed at the leading (reactor) ends and serve as the pressure barrier between the reactor pressurized water and the containment atmosphere. The thimbles are shielded from coolant flow by conduits along most of their lengths. During normal operation, the retractable thimbles are stationary and move only during refueling or for maintenance. Whereas the oldest plants had few or no bottom–mounted instrumentation tubes (Yankee Rowe and San Onofre 1 have none, Connecticut Yankee has 19), the majority of Westinghouse plants have 58 tubes.[12]

7.2 Stressors

The important CRDM stressors include the thermal transients that occur during plant heatups and cooldowns, the movements or stepping of the rods that occurs during normal operation, temperature and radiation (as they affect the electrical insulation), and the high–temperature corrosive environment inside the CRDMs. The heatups and cooldowns can cause fatigue damage, and have been discussed in Sections 3.2 and 5.2 of Volume 1 of this report. The latchings and unlatchings can cause metal fatigue and mechanical wear over time. All the electrical subcomponents are subject to insulation breakdown caused by temperature and radiation, and must be cooled to ensure adequate reliability. Prolonged exposure to corrosive environments and high temperatures can potentially lead to component degradation, such as the thermal embrittlement of cast stainless steel components discussed in Section 5.3.2 of Volume 1, or stress corrosion cracking discussed in Section 6.4.5 of Volume 1. However, PWR CRDMs have not experienced stress corrosion cracking problems to date, primarily because the water chemistry quality inhibits stress corrosion cracking, and the CRDM subcomponents are not highly stressed as are some of the reactor internals connectors that have experienced intergranular stress corrosion cracking (IGSCC).

The flow–induced loads, radiation, and the high–temperature corrosive environment are the major stressors acting on the reactor internals.[13] As described in Section 7.1.6, there are many small or thin subcomponents such as in–core flux instrumentation, that constitute portions of the reactor internals. PWR coolant flow velocities are high, and the flow changes direction as it passes through the core region, resulting in high–frequency oscillating loads. Differences in temperature in the various core regions and uneven gamma ray absorption resulting from component location with respect to the core (subcomponents closest to the core will be heated more than those further away) also cause regions of thermal stress. The metal is also degraded by prolonged exposure to the neutron flux. Gravity, differential pressure, and bolt preloads all act together to add further stresses to the reactor internals. This is particularly a problem for the bolt and pin connectors, because stainless steel is more susceptible to IGSCC when it is stressed by a high tensile loading. Control rod motion can cause wear on guide tubes. Although flow–induced vibration is the main source of wear, cleaning, and insertion and retraction during operation of the in–core flux instrumentation also causes wear on thimbles. As the cleaning tools and flux wires are inserted and retracted, they make contact with the walls of these thin stainless steel tubes.

7.3 Degradation Sites

The primary CRDM degradation sites subject to fatigue damage are the pressure housing, seal welds, and the coupling between the CRA and the CRDM. However, typical fatigue usage factors are low (less than 0.1 versus an allowable usage of 1.0) for CRDM components. Cast stainless steel housings are also susceptible to thermal embrittlement. It is not known how many of the pressure housings in U.S. pressurized water reactors are made of cast stainless steel, but 10 of the 45 housings at the Surry 1 plant are cast stainless steel.[5]

The internal CRDM components, such as latches, roller nuts, drive rods, springs, etc., are subject to mechanical wear, as are the bearings, which can experience spalling in their races over the reactor's lifetime. Insulation breakdown is the primary concern for electrical components.[5]

A study of CRDM failures at 31 Westinghouse operating plants was published by the Westinghouse Electric Corporation in 1985.[4] The information covered more than 1.5 million total CRDM hours of operation and 63 CRDM failure events. The failure locations are as follows:

Location	Number of Failures	Percent of Total Failures
Coil stack assembly: electrical	19	30
Pressure housing assembly	11	17.5
Coil stack assembly: other	6	9.5
Drive rod assembly	2	3
Latch assembly	1	1.6
Unknown	24	38

The category "unknown" reflects insufficient information in the event reports to assign a specific failure location. Although the Westinghouse report did not mention the consequences of the failures, a review of the overall CRDM failure data base in References 14 and 15 leads to the conclusion that most CRDM failures have resulted in a dropped control rod or a minor leak.

Some of the pressure housing failures resulted in small leaks in the vicinity of the CRDM seal welds. For example, several pinhole leaks were found in the CRDM canopy seal welds at the Robinson 2 (Westinghouse) plant in 1978, and a leak in the seal weld of the threaded connection between the CRDM housing and its adapter in the Beznau 1 reactor was detected in 1970.[16,17] Failed CRDM pressure housing seals at the Palisades plant also have resulted in reactor coolant system leaks.[18]

Closure studs on reactor coolant pumps, pressurizers, and steam generator subcomponents have experienced corrosion wastage from boric acid attack caused by coolant leakage.[19] The boric acid present in the leaking primary coolant has also caused corrosion damage to the reactor pressure vessel base metal.[20] Since the CRDM closures could also be subject to such attack, the NRC has required PWR licensees to monitor the CRDM flanges including the holddown bolts for this type of degradation (CRDMs with an omega seal design were excluded from this action).[21]

Numerous bolts and pins that attach or align the larger reactor internals components, such as the thermal shields and core barrels, have failed. Thermal shield bolts (Type 316 stainless steel) in the Westinghouse-designed Yankee Rowe plant failed in 1968 because of flow-induced vibration.[13] Cracks developed in the thermal shield and lateral support pins in the Combustion Engineering-designed Millstone 2 and St. Lucie 1 plants, leading to loose parts and damage to the core barrel at one of those plants. Degradation of the thermal shield bolts in the Maine Yankee reactor led to loosening of the thermal shield. In 1972, improper torque on the Type 304 stainless steel bolts on the holddown ring in the Palisades plant caused them to loosen under flow-induced vibrational loads, resulting in a broken bolt head migrating through the reactor coolant system to the steam generator inlet plenum.[13] The Westinghouse plants have also experienced several problems with control rod guide tube split pins.[22] Damaged bolts and dowel pins on support blocks between the Connecticut Yankee core support barrel and thermal shield were discovered during the 10-year inservice inspection of the reactor vessel in 1987. The bolts and pins had shifted and jammed, and were replaced.[23] The damage was attributed to wear of displacement limiters from the long-term effects of flow-induced vibration. More recently, 3 of the 30 bolts used to anchor the San Onofre 1 thermal shield were found during a routine inspection to be cracked.[24]

Smaller subcomponents, such as surveillance holder tubes and in-core instrumentation conduits, have experienced failures caused by flow-induced vibration and wear. For example, 21 of 54 in-core instrument nozzles in the Oconee 1 plant cracked or were broken in the weld region owing to flow-induced vibration early in plant life. In many cases, the problems were primarily design-related rather than aging-related; however, they illustrate the potential synergistic degradation that aging aggravated by flow-induced vibration can produce. Unisolatable leaks have occurred in instrumentation guide tubes and their associated fittings because of failures during operation.[25] High-strength Ni-Cr-Fe springs, such as fuel assembly fingers (Alloy X-750) and control component holddown springs (Alloy 718), have also failed during operation.[26] Flow-induced vibration caused beginning-of-plant-life burnable poison rods in the Crystal River 3 plant to break, and subsequently they were transported through the reactor coolant system to the steam generator inlet plenum. This resulted in considerable damage to the primary-side steam generator tube end welds (of which there are over 15,000 in each steam generator). A failure of the assembly latch appears to be the cause of the problem. Baffle jetting at the Trojan plant caused damage to fuel assemblies.

Problems caused by flow-induced-vibration are either (a) design-related and show up early in life, or (b) aging-related and occur only after some other degradation mechanisms, such as IGSCC or loss of bolt preload, have loosened the reactor internals. The Westinghouse life extension study of the Surry 1 reactor internals has identified 21 locations having a medium-to-high probability of potential aging problems.[5,27] These results were carefully studied, along with the discussions in this chapter, to arrive at the summary of potential degradation processes presented in Section 7.7.

7.4 Degradation Mechanisms

Individual degradation mechanisms are described separately in this section, but keep in mind that in some cases two or more aging degradation mechanisms will occur at the same time, for example, the Babcock & Wilcox thermal shield bolt failures were caused by both IGSCC and high-cycle fatigue.

Degradation mechanisms are discussed in their relative order of importance, with the reactor internals generally discussed first because they have been more prone to failures than the CRDMs. In some cases, we do not know the exact cause of the degradation mechanism. This is particularly true for CRDM housing leaks; an instance is the pinhole leaks in the H.B. Robinson 2 canopy seal welds mentioned in Section 7.3.[16] Faulty welding or contaminants in the weld may have been significant contributors.

7.4.1 High-Cycle Fatigue. Figures 7.11 and 7.12 show the ASME design fatigue curves for stainless steels plotted as the alternating stress intensity at a location versus the number of cycles to failure at this stress. Figure 7.13 shows the design curve for high-strength bolting. The curves are based on the results of uniaxially strained specimens tested in air. Strain values were converted to stress units by means of the elastic modulus (E). When the stress exceeds the proportional limit, the stress calculated is actually a fictitious stress. Thus, the stress amplitude is $(\Delta\varepsilon/2) \times E$, where $\Delta\varepsilon$ is the strain range. Least-squares curves were fitted through the data, and a reduction factor of 2 on stress and 20 on cycles, whichever was more conservative for a given point, was used to establish the design curves. The effect of maximum mean stress was included in the high-cycle regions of the design curves. The fatigue usage for the various transient combinations is determined by first calculating the peak alternating stress intensity for each combination and determining the allowable number of cycles (N) from a curve such as Figure 7.11. This number is divided into the design cycles (n) to determine the fatigue usage (U) for this group of cycles. The cumulative fatigue usage for all transients is the sum of the individual usages, that is,

$$\text{Cumulative usage} = \sum U = \sum \frac{n}{N} .$$

By Miner's rule, if the cumulative fatigue usage is less than 1.00, then the acceptance criterion is met.

For many metals, including steels, the fatigue curve flattens at a given number of cycles (10^6 to 10^8 cycles is generally considered typical for steels). The stress at this point is called the fatigue limit. If the alternating stress for a particular event does not exceed the fatigue limit, the member will not fail in high-cycle fatigue, that is, the number of allowable cycles at this stress is infinite. The ASME fatigue curve for stainless steel has been extended to 10^{11} cycles (Figure 7.12). However, for high-strength bolting and carbon steel the alternating stress at 10^6 cycles is still considered to be the fatigue limit. This concept is based on material tested in air, however, and the existence of a fatigue limit in the presence of corrosion-assisted fatigue has not been proven. In addition, small-amplitude cycles can be damaging if there are a few large-stress cycles in the earlier loading history that produced significant plastic deformation.[28] The effects of high-cycle fatigue were not generally included in the original design.

Although reactor components have been designed to minimize thermal gradients in the metal during operational transients, thus limiting low-cycle fatigue, several reactor internals locations still may experience relatively high fatigue usage from high-cycle flow-induced vibrations. Failures caused at least in part by high-cycle fatigue have occurred in some of the older Westinghouse plant thermal shield bolts; the Combustion Engineering Palisades reactor internals holddown ring (partially attributed to insufficient holddown spring force); and some of the Babcock & Wilcox surveillance specimen holder tubes, burnable poison rod assemblies, and fuel assembly hold-down springs (partially attributed to the use of Alloy X-750 material with coarse grain size). The cores of the Trojan and other plants have been damaged by baffle-jetting.[14,15,22] This resulted in loose fuel pellets in the reactor internals and was attributed to water-jetting-induced motion of the fuel rods adjacent to baffle plate joint locations with enlarged gaps. Fuel was also damaged in 1985 at the Point Beach 2 plant by baffle jetting.[22]

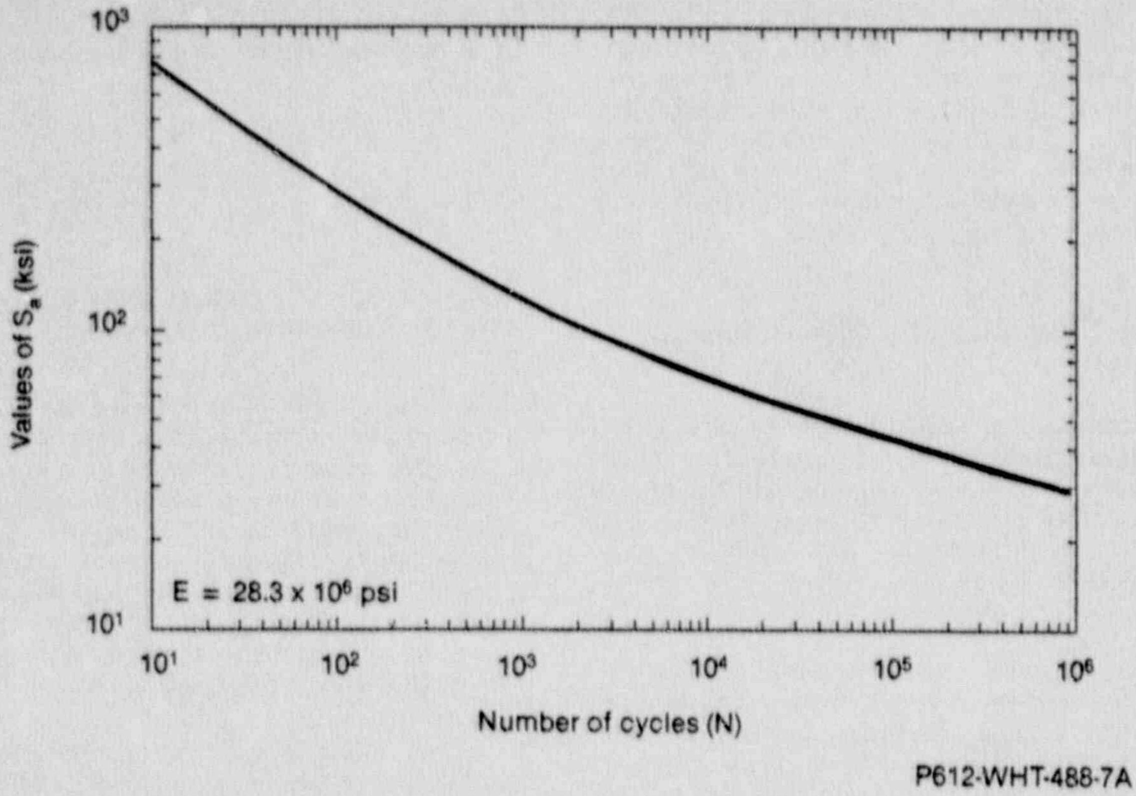


Figure 7.11. ASME Code low-cycle fatigue curve for stainless steel.

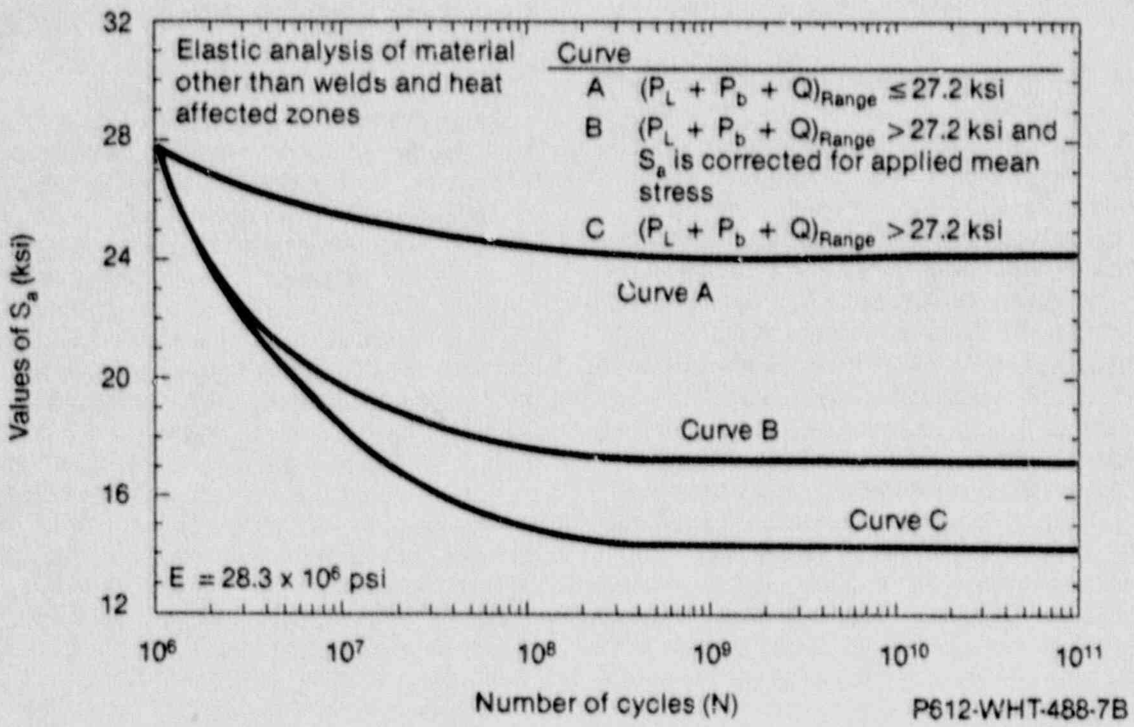


Figure 7.12. ASME Code high-cycle fatigue curves for stainless steel.[8]

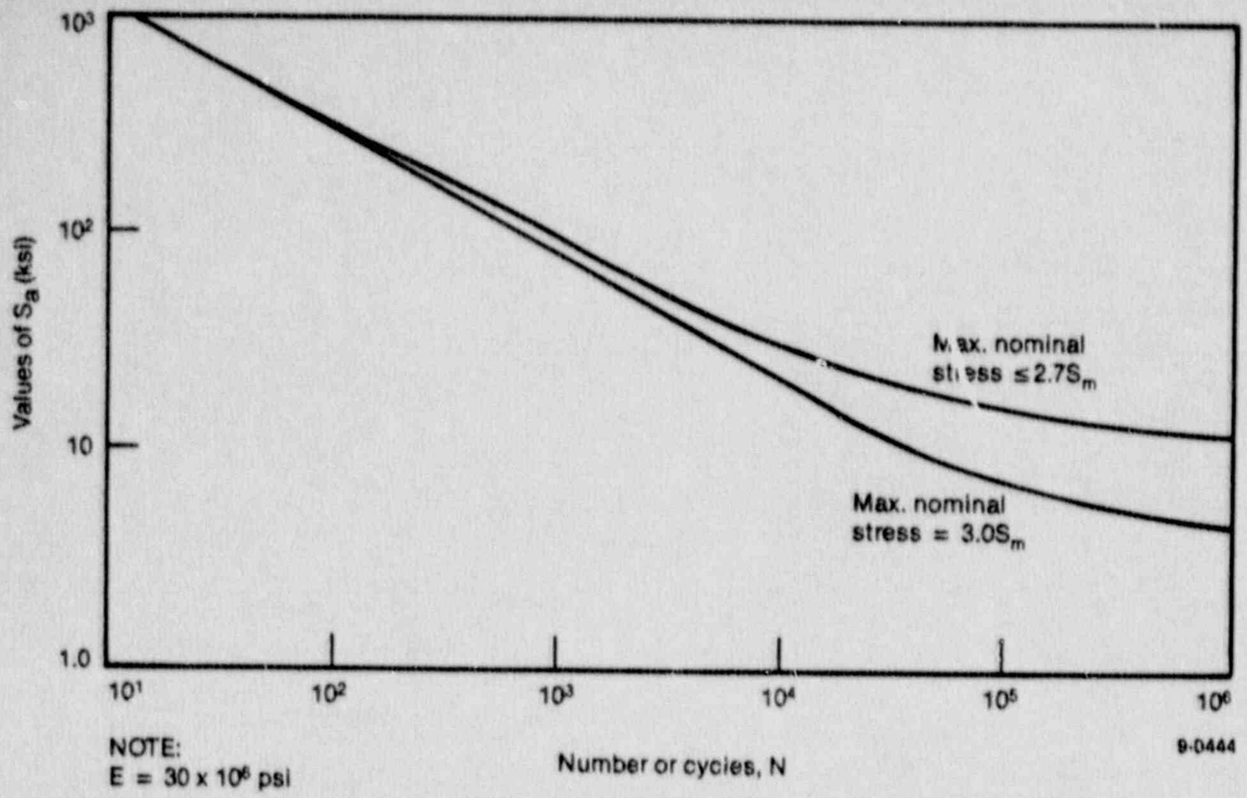


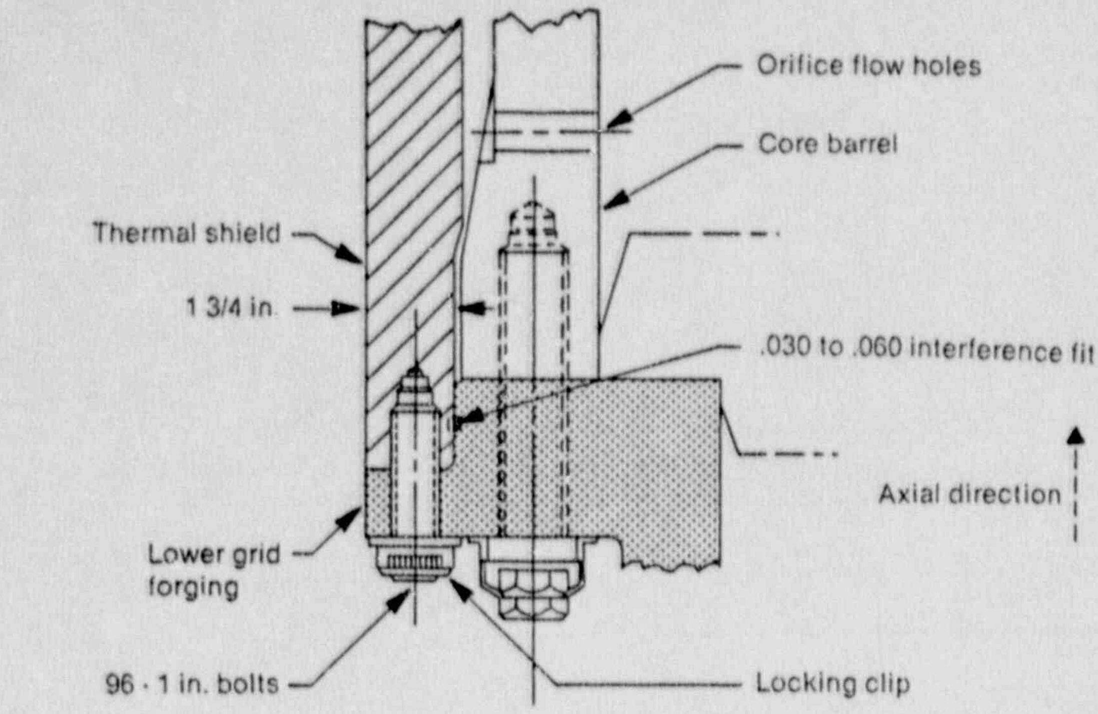
Figure 7.13. ASME Code design fatigue curve for high strength steel bolting.[8]

The thermal shield support systems on two Combustion Engineering plants have been damaged by hydraulically induced loadings, that is, coolant flow through and around the core and the reactor internals. During a refueling outage at St. Lucie 1 in 1983 (at age 7 years), two of nine thermal shield support pins were discovered to be missing, two of nine upper positioning pins were missing, and all pins showed some wear or damage. Also, lugs welded to the core barrel to support the thermal shield were damaged.[22]

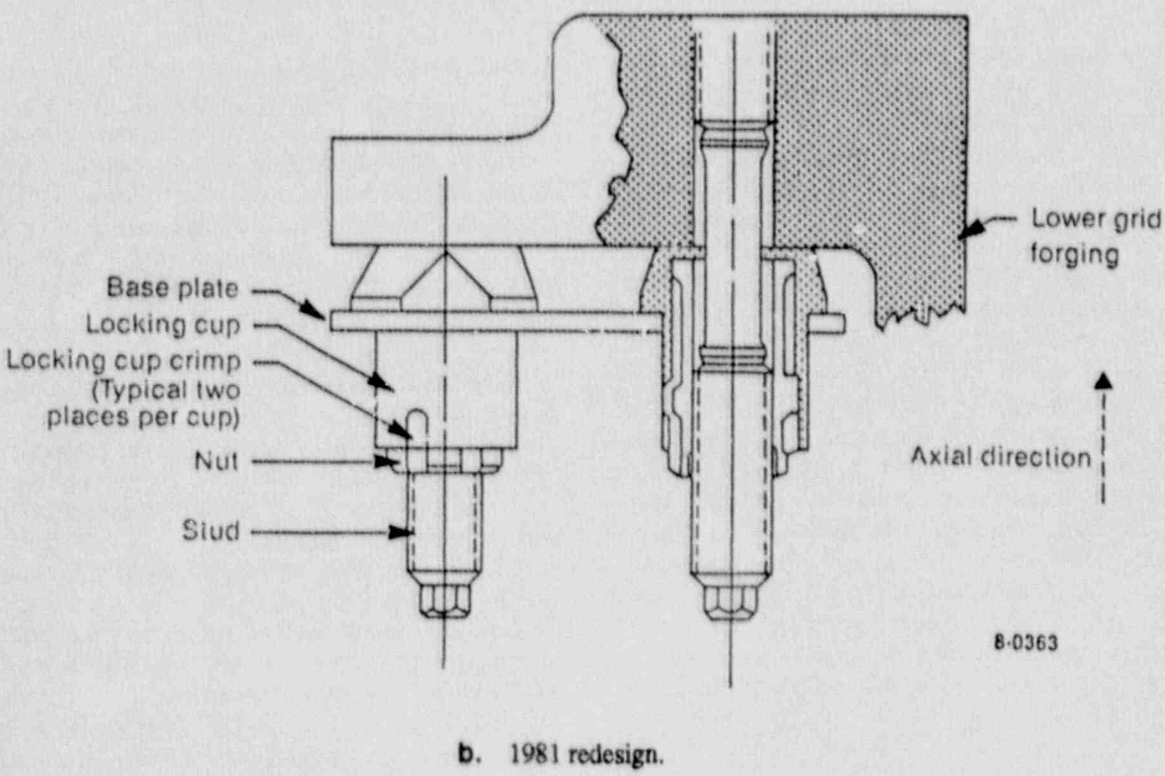
Similar damage was found at the Millstone 2 plant (at age 8 years) in 1983. Upon removal of the thermal shield, a through-wall crack in the core barrel was discovered. The core barrel crack was attributed to the fact that the deterioration in the thermal shield support system placed additional loading on the core barrel. No evidence of corrosion as a contributing factor was reported. A solution to the problem has been to drill a hole at each end of the core barrel cracks and to remove the thermal shield[22] (thus, the thermal shield is not shown in Figure 7.6).

High-cycle fatigue design problems are generally found early in core life. For instance, extensive damage to the tube ends and to the tube-to-tubesheet welds of one of the two steam generators was found in March 1972 following the first phase of the hot functional testing at the Oconee 1 plant.[29] The cause was loose parts from failed reactor internals, primarily 19-mm- (0.75-in.-) diameter in-core instruments that penetrate the bottom of the reactor vessel. Of the 52 nozzles, 21 had broken off and 14 others had cracks in the region of the weld because of flow-induced vibrations. In addition, four in-core instrument guide tube extensions were broken and four were cracked.

At the same time (about 1972), the retention welds on each of the eight dowels at the lower edge of the Oconee 1 thermal shield were found to be broken; one of the dowels had even backed out about 19 mm (0.75 in.).[30] This connection was redesigned to the configuration shown in Figure 7.14a. In 1981, four of the 96 bolts connecting the thermal shield to the lower grid flow distributor were found to be missing (discussed further in Section 7.4.2), and about 80% of the remaining bolts were backed out (loosened) from 2.5 to 13 mm (0.1 to 0.5 in.). This led to a further redesign shown in Figure 7.14b. The 96 individual bolts and locking clips were replaced with 48 Alloy X-750 stud and nut assemblies consisting of 2 studs connected by a Type 304 stainless steel baseplate. Each stud, nut, Type 304 stainless steel locking clip, and baseplate was first assembled, then installed in the existing threaded holes in the thermal shield. A stud tensioner



a. Pre–1981 design.



b. 1981 redesign.

Figure 7.14. Babcock & Wilcox thermal shield bolt design.[30]

then tensioned the studs and set the nuts. Finally, the locking clip, which was wired to the baseplate, was crimped onto the nut.

Although a fatigue lifetime for the various reactor internals of greater than 40 years was calculated in the original design analysis, the design curves used in confirming the 40-year original plant lifetime were based on the ASME fatigue curves shown in Figures 7.11 and 7.13, for undegraded material. The fatigue curve of Figure 7.12 was added later, so high-cycle fatigue damage caused by stress amplitudes less than the fatigue limit at one million cycles may not have been accounted for in the design of stainless steel components. There is presently no high-cycle fatigue curve for high-strength bolting.

Corrosion-assisted fatigue may occur at degraded sites under stresses less than predicted by the ASME fatigue curves.[14,15,18,22] Japanese data have shown that the fatigue strength of Types 304 and 316 stainless steel is reduced in the presence of high-temperature water, especially in the 10^4 to 10^5 cycle region.[31] Although these data are for a BWR environment, the effect of the PWR environment on the fatigue strength of stainless steels should also be investigated. High-strength, highly preloaded bolts and pins, and weld locations where crevices or stress concentrations, or both, are present are particularly susceptible. There have been a number of cases where stress corrosion has initiated cracks in reactor internals (discussed in Section 7.4.2), and high-cycle fatigue from flow-induced vibrations has propagated the crack to failure.[22,32,33] Some Babcock & Wilcox thermal shield bolt failures are attributed to corrosion-assisted fatigue. Design curves to account for high-cycle fatigue and the variation in fatigue strength based on environment are being investigated by ASME Code Committees, and guidance on long-term corrosion-assisted fatigue will hopefully be added to the ASME Code in time.

7.4.2 IGSCC The PWR water chemistry environment has proven to be very effective in preventing this phenomenon except in the reactor internals, although IGSCC has been a significant problem in BWR austenitic stainless steel (Types 304, 304L, 316 base metal, and 308 weld metal) recirculation piping and safe ends. Pins, bolts, and springs in PWR (as well as BWR) reactor internals are made of high-strength steel such as Alloy X-750 and Alloy A-286, and have been degraded by IGSCC.[13]

IGSCC of PWR reactor components requires a presence of a susceptible microstructure and a high level of tensile stresses, which are the result of the procedures used for heat treatment and assembly of components. The heat treatment of Alloy X-750 components included solution-annealing at typical temperatures ranging from 885 to 1150°C (1625 to 2100°F) followed by thermal aging at temperatures ranging from 620 to 840°C (1150 to 1550°F). Use of lower solution-annealing temperatures results in absence of chromium carbides at grain boundaries in Alloy X-750 and makes it susceptible to IGSCC, as is the case for the primary side of PWR steam generator Alloy-600 tubes. (See Section 8.2.2 for further discussion on primary side degradation of recirculating steam generator tubes.) Use of higher solution-annealing temperatures results in presence of chromium carbides at the grain boundaries and, therefore, improved IGSCC resistance. Higher solution annealing temperatures are now used for Alloy X-750 replacement components to mitigate IGSCC. High tensile stresses causing IGSCC damage, include the residual stresses resulting from welding and those from applied mechanical and thermal loadings. High preloads in the reactor internals pins and bolts, intensified by areas of stress concentrations at threads and bolt-to-head transitions, are an example of such loadings.[5,26,34] High-strength pins and bolts in the reactor internals whose failure has been at least partly attributable to stress corrosion cracking include the core baffle bolts, guide tube support pins, core barrel bolts, and thermal shield bolts.

The Babcock & Wilcox thermal shield support bolts have had particular problems. Several thermal shield-to-lower grid assembly bolts in the Oconee 1 plant were found to be broken during a 10-year inservice inspection in 1981. Subsequent ultrasonic tests of the remaining bolts showed that 94 of 96 bolts had crack indications. The failures are attributed to the borated water environment, high preload, IGSCC, and high-cycle fatigue. The lower thermal shield was redesigned and the Alloy A-286 bolts were replaced with Alloy X-750 material. Upon examination of the Oconee 2 thermal shield bolts during a 1982 outage, 3 were found to be broken and 24 cracked. Afterward, the Babcock & Wilcox Owners' Group instituted a program of bolt inspection and repair. This program was later responsible for the March 1983 discovery of similar failures of bolts in the upper core barrel-to-core support shield joint at the Rancho Seco plant. In April of 1983, ultrasonic testing of the Crystal River 3 reactor internals showed abnormal indications in four lower core barrel bolts and in a number of upper core barrel bolts. The results from the Oconee 1 and 2 and Rancho Seco examinations indicate that IGSCC in the bolt head-to-shank regions (see Figure 7.15) was at least partially responsible for the degradations.[35]

The fractures in the Babcock & Wilcox Alloy A-286 bolts were located near fillets and showed little

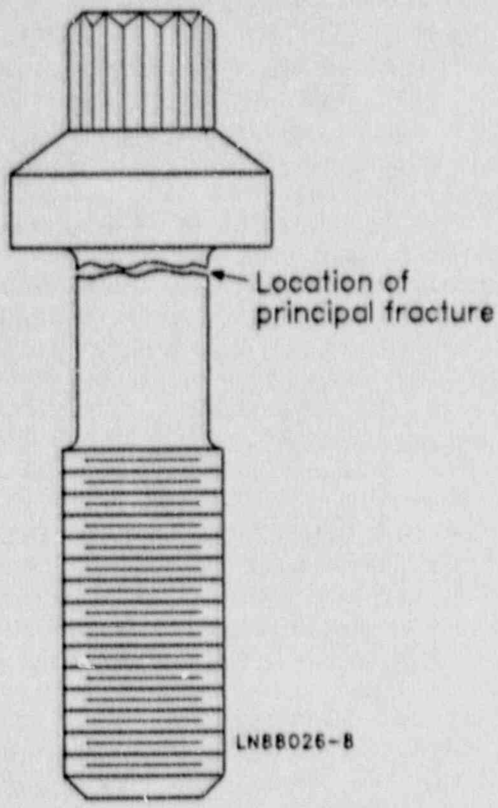


Figure 7.15. Failure location of Babcock & Wilcox bolts.[35]

ductility. There was intergranular cracking with indications of grain boundary corrosive attack and fretting (thermal shield bolts only), and mechanical fatigue. The bolt failures were attributed to environmentally-assisted intergranular cracking or corrosion fatigue, or both. No failures were found in bolts with moderate to low stresses.[35] Laboratory tests show that materials processed by cold working prior to heat treatment (cold reduction of 40 to 50%) or by hot heading (or both) during bolt fabrication are more susceptible to IGSCC.[36] Heavy cold-working of a solution-treated material can create high dislocation densities near grain boundaries. These high-energy sites promote preferential precipitation at the grain boundaries during subsequent thermal treatments. Another possible cause of IGSCC susceptibility is increased concentration of environmentally sensitive grain-boundary segregants, such as phosphorous and sulphur produced during material processing. The hot-heading procedure produced a heat-affected zone in the area of the failure.

Stress corrosion cracking has also been a problem in five Kraftwerk Union plants completed between 1974 and 1979.[33] Material damage to Alloy X-750 screws, each measuring 120 by 160 mm, has been detected during routine ultrasonic tests of reactor internals. High stresses may have resulted from the then-standard procedure of screwing the core guide plates to the core barrel and spot welding over the screws. The welds may have produced locally high stresses in the screws. The weld procedure is no longer used, and the Alloy X-750 screw material is being replaced by austenitic material.[33]

Stress corrosion cracking has caused failure of support pins (commonly referred to as split pins), that are bolted to the bottom of each control rod guide tube in Westinghouse-type plants. The majority of these failures occurred in the pin shank early in life (<5 refuelings). Figure 7.16 shows the failure location in the split pin.[37,38] The first failure of a split pin in a domestic PWR plant occurred at North Anna 1 in May 1982.[22,39] Parts of the failed split pin caused damage to 75% of the tube ends in the North Anna 1 steam generators. The pins were made of Alloy X-750, solution-heat-treated at temperatures less than 982°C (<1800°F) for short times, age-hardened, and highly stressed (60,000 psi nominal stress on the shank and 130,000 psi on the leaf spring section of the pin). The failures occurred in the region of high stress, caused by over-torquing of the nut. Westinghouse now recommends that the pins be solution heat-treated at temperatures equal to 1093°C (2000°F), and age-hardened at 764°C (1300°F) for 20 h to minimize the stress-corrosion cracking problem. To reduce the high stresses, Westinghouse recommends that the torque on the lock nut be reduced from 285 N · m (210 ft-lb) to 191 N · m (140 ft-lb), and the use of redesigned replacement pins. The modified design includes a larger size pin and peening of the nut. Prior to the North Anna 1 failure, split pins also had failed at Japan's Mihama 3 and France's Fessenheim 1 plants. Several United States plants have replaced their split pins since the North Anna 1 failure. Most were replaced as a precautionary measure; however, three units (Trojan, Point Beach 1, and Farley 1) have had to replace broken split pins.

Although there have been no reported problems with the redesign outside France, Electricite de France (EDF) replacement split pins installed between 1982 and 1985 have experienced cracking. The EDF Gravelines 1 reactor's acoustic monitor detected evidence of a loose part in a steam generator in February 1988 that turned out to be a split pin. Subsequent ultrasonic inspections indicated that about half the prongs on the unit's split pins are suffering from stress corrosion cracking. A second pin was found in one of the steam generator water boxes in May 1988.[40] In 1987, 25% of the split pins in EDF's Tricastin 4 were found

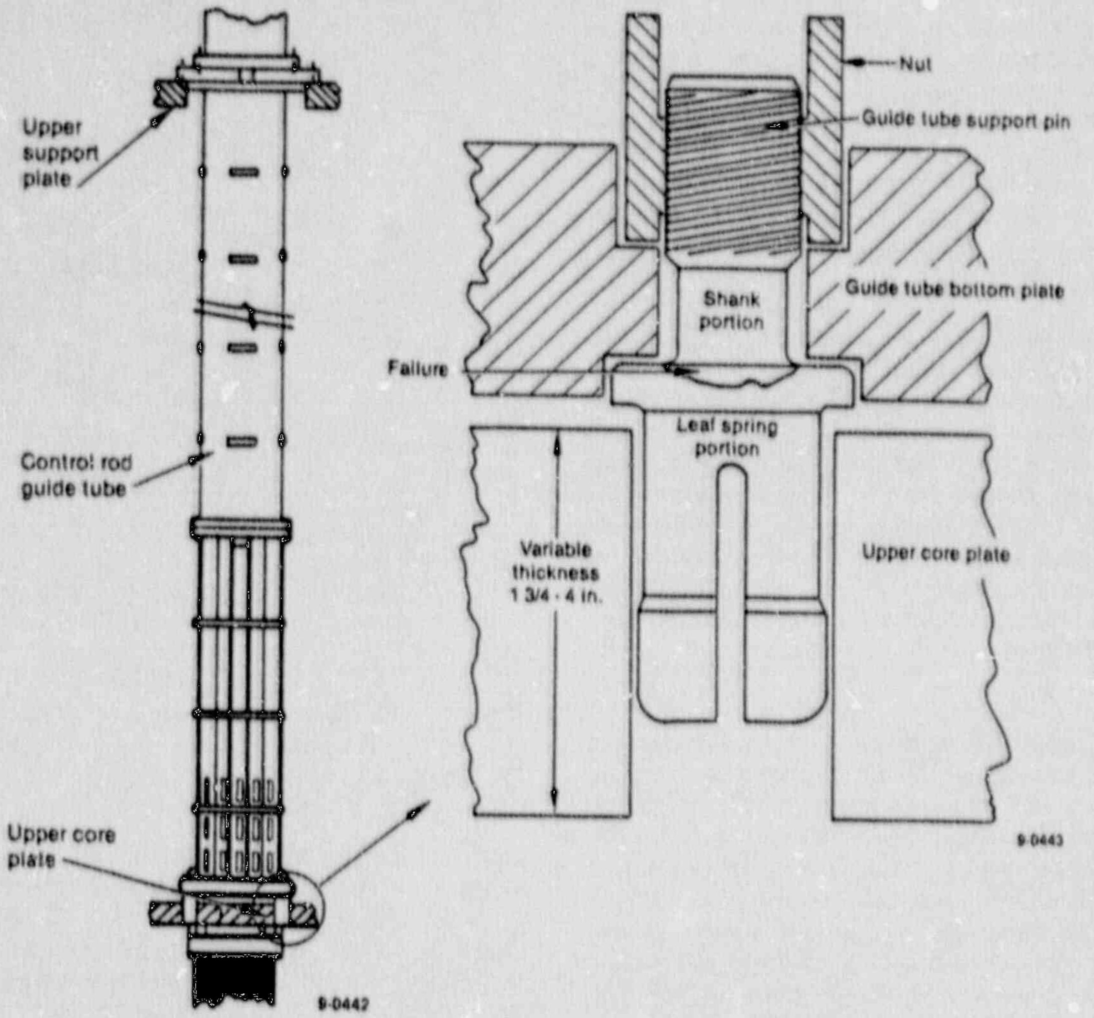


Figure 7.16. Failure location of Westinghouse split pins.[37,38]

to have cracks. Since split pins are not routinely inspected, it is not known whether the pins in other reactors have cracked or not, since no split pin loose parts have migrated into primary circuits.[41] Nor is there any definite conclusion as to why the Westinghouse replacement pins are apparently surviving better than the EDF replacements pins.[42]

The Alloy A-286 bolting material has also been shown to be susceptible to IGSCC in Sweden and Finland.[26] Numerous studies have identified that high-temperature annealing [1060 to 1150°C (1940 to 2100°F)] plus single aging at about 700°C (1290°F) improves the stress corrosion cracking resistance of Alloy X-750. Alloy 718 has not experienced IGSCC in reactor internals, but its fatigue properties are weak and, thus, it has not been widely used.[26]

Further discussions on IGSCC may be found in Sections 5.3.3 and 10.4 of Volume 1 of this report.

7.4.3 Wear. All mating subcomponents in the CRDM will experience mechanical wear to varying degrees. Consequently, vendors have performed life tests on the mechanisms to determine the allowable number of cycles for design lives. Although these tests have not been allowed in all cases to progress to the point of absolute failure of the CRDM to function, they have, nevertheless, been used to justify functionality during a 40-year life.[4] Metal wear may take the form of spalling, as in the raceways of bearings, or the slow rubbing away of material on gears, latches, or other mating parts. In long-term life tests conducted by Westinghouse, the subcomponent showing the most wear were the latch teeth.[a] If the wear were allowed to progress, the tooth would eventually develop a knife edge and the CRDM would misstep. However, this has not occurred in plant operation because the number of steps has not approached the number required for significant wear in the life tests.

The Palisades plant has accounted for the majority of all the lost equivalent full-power hours caused by CRDM problems in Combustion Engineering plants. Palisades and Fort Calhoun have rack-and-pinion CRDMs that require a pressure boundary seal against the rotating control element drive shaft. Although the CRDMs have performed acceptably at Fort Calhoun, seal leakage has been a continuing problem at Palisades. Problems with the rack-and-pinion design clutch brake assembly have also occurred at the Palisades plant.

Movement of the neutron in-core flux monitors (see Figure 7.1) can cause wear in their guides. Also, thimble tube thinning can be caused by flow-induced vibration. The thimble tubes in the Westinghouse-designed plants constitute part of the primary pressure boundary. These tubes are supported by guide tubes within the lower vessel region and the fuel assemblies, and by high-pressure conduits between the reactor vessel and the seal table. However, a small portion of the thimble tube is directly exposed to the RCS flow (see Figure 7.17). This exposed portion is between the top of the lower core plate and the bottom of the fuel assembly. Many plants have detected thimble wear and several instances of leaks. Wall thinning was identified in 23 out of 50 thimble tubes in the North Anna 1 plant; one tube thinned as much as 49%.[1] Thinning has also been detected in the thimble tubes at the Farley 1 and Salem 1 plants. In addition, in-core thimble tube thinning and leakage has been detected in facilities in France and Belgium. Nineteen of the 58 thimble tubes in the D. C. Cook 2 plant were found to have more than 60% wall thinning. Westinghouse sets 60% thinning as a replacement criterion.[43] The South Texas 1 plant has experienced thimble tube wear in its first year of operation. More than 70% of the tubes showed wear after 32 weeks of full-flow operation. One exhibited wear of 60% of the wall thickness.[44]

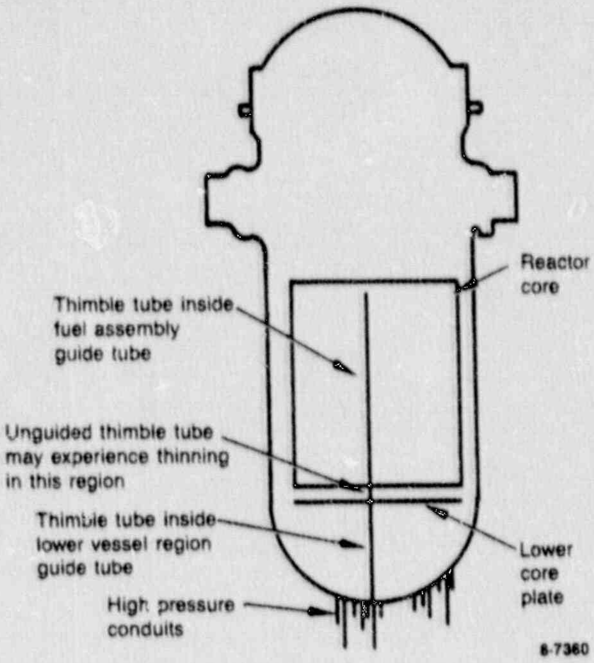


Figure 7.17. Westinghouse incore instrument guides.

Initially, the utility installed flow-limiting devices in an attempt to shield the tubes from cross-flow. When the problem continued, the utility removed the previously installed flow-limiting devices, installed thicker-walled tubes, and installed both a manual isolation valve and a magnetic ball check valve on each tube.[45]

Although Combustion Engineering and Babcock & Wilcox plants also contain in-core flux monitoring instrumentation, the support and sealing designs are different from the Westinghouse design, and no problems have been reported.

Reactor internals keys and pins may also experience wear over plant lifetime. The core barrel at the Palisades plant was loosened by wear caused by flow-induced vibration.[46] The wear occurred where the core barrel was clamped between the pressure vessel and vessel head (see Figure 7.18).

Movement of the CRAs causes wear of their guide tubes.

7.4.4 Thermal Embrittlement. The CRDM pressure housings fabricated from cast stainless steel will experience some (unknown) thermal embrittlement, as will all cast stainless steel primary coolant

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a. D. Bird, private communication, Westinghouse Cheswick Division, March 30, 1989.

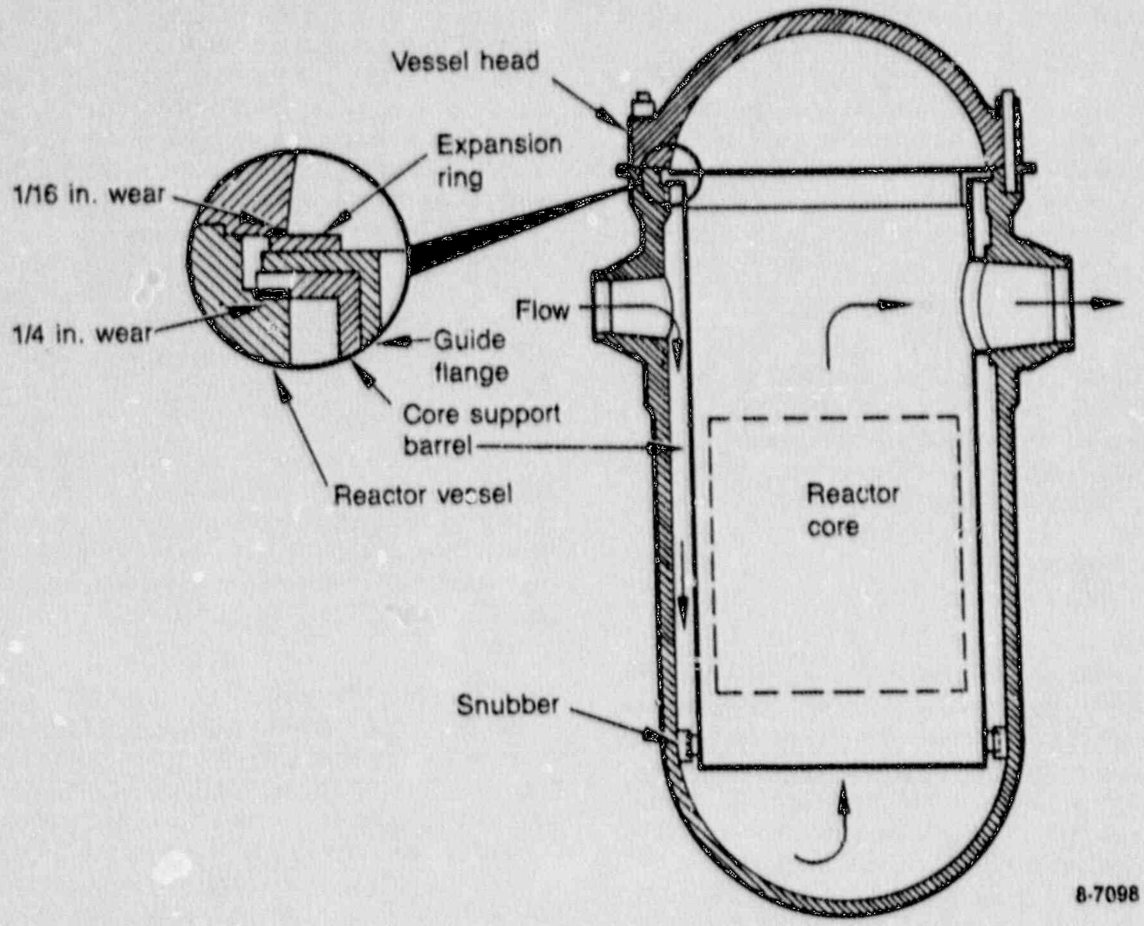

Figure 7.18. Wear location from Palisades core barrel motion.[1]

components. Ten CRDM housings at Surry 1 are made of cast stainless steel, whereas the remaining 35 housings are made of wrought stainless steel.[5,26] It is not known what percent of CRDM housings in other plants are made of cast stainless steel.

Although most of the reactor internals subcomponents are made of stainless steel, a small portion are cast. For instance, parts of the Combustion Engineering upper guide structure assembly and the CRA shrouds are made of cast Grade CF–8 stainless steel and could be susceptible to thermal embrittlement. Some early Westinghouse plant flow mixers, lower support structures, and cruciform instrumentation guides are made of cast stainless steel.

Thermal embrittlement of stainless steel castings is caused by changes in the ferrite phase in the ferrite/austenite microstructure of these alloys. The austenite phase is ductile and remains so after thermal exposure; thus, when the fraction of ferrite is small, the degree of overall embrittlement of the casting is low, but when the fraction of ferrite is somewhat larger and the ferrite is interconnected, the entire casting may become embrittled. If the components used in internals are subjected to high levels of irradiation, the austenite phase could become embrittled as well. The overall structural integrity of the casting could be in question when both the austenite and ferrite phases are embrittled.

As part of any license renewal process, those components made of cast stainless steel should be clearly identified and the potential degree of thermal embrittlement estimated. Components susceptible to thermal embrittlement should be inspected for any cracks. Thermal embrittlement of cast stainless steels has not been fully investigated, and is currently being examined by the Westinghouse Electric Corporation Owners' Group,[5] EPRI,[47–50] and the USNRC.[51] Thermal aging is discussed in more detail in Sections 5.3.3 and 10.4 of Volume 1 of this report.

7.4.5 Irradiation Embrittlement.[52] Tensile properties of Type 304 stainless steel and Alloy 600 change at fluences exceeding 5 x 10^{20} nvt (>1 MeV). Uniform elongation of Type 304 stainless steel decreases to <1% at fluences exceeding 1×10^{21} nvt (>1 MeV). A typical fluence at the end of 32 full-power years is about 10^{22} n/cm^2 at the baffle plate and about 10^{20} n/cm^2 at the core barrel.[53] Depending on the fluences at different core locations, the reactor internals could be susceptible to embrittlement, stress relaxation, and loss of strength. One-half the subcomponents assessed in the Westinghouse study of the Surry 1 plant, were considered susceptible to some form of embrittlement (thermal or radiation).

Stainless steel components in BWR environments are susceptible to irradiation-assisted stress corrosion cracking and they are discussed in Chapter 11. However, the chemistry of the PWR coolant is significantly different than that of the BWR coolant, and, therefore, the stainless steel reactor internal components in PWRs have not shown susceptibility to irradiation-assisted stress corrosion cracking.

7.4.6 Boric Acid Corrosion. Leakage of primary coolant may cause boric acid corrosion of several exposed CRDM components. The primary coolant contains boric acid and some lithium hydroxide in solution, and its pH varies over the range of 4.2 to 10.5. The boric acid in the leaking primary coolant may cause wastage or general dissolution corrosion of carbon steel and low-alloy steel components. The corrosion rate appears to depend upon the pH of the solution, the solution temperature, and the boric acid concentration in the solution. Some studies have shown that the corrosion rates of steel at pH values of 8 to 9.5 are six times those at pH values of 10.5 to 11.5.[54] As temperatures increase to the boiling point of water, the water evaporates, the solution concentrates, and the corrosion rate increases at much faster rates. Concentrated boric acid is highly corrosive at ~200°F.

Field experience and test results indicate that the corrosion rates for carbon steels and low-alloy steels exposed to primary coolant leakage are greater than previously estimated and could be unacceptably high. In one incident, the leakage ran down one side of the Salem 2 reactor vessel head insulation and much of it leaked under the insulation to the bare reactor vessel head. Three reactor vessel head bolts were severely corroded and had to be replaced.[55] In addition, nine corrosion pits of 25 to 76-mm (1 to 3-in.) diameter and 9 to 10-mm (0.36 to 0.4-in.) deep were found in the reactor vessel head.[20] Turkey Point 4 personnel discovered more than 227 kg (500 lb) of boric acid crystals on the reactor vessel head in 1987. The cause was a leak from a lower instrument tube seal (conoseal) of one of the in-core instrument tubes.[56] About one cubic foot of boric acid crystals had been removed from the same area in 1986. Vapors containing water-soluble boric acid had been borne into the upper CRDM area, and into the CRDM cooling coils and ducts. The CRDM cooling shroud support was severely corroded and required replacement. The rod position indicators contained boric acid residue. The instrumentation port column assembly experienced corrosion on the external surface and erosion on the internal surface of the clamp ring. There also was damage to the vent shroud support, the pressure vessel studs and nuts, and the head flange ligament area (see Figure 7.19).[57]

The observed boric acid corrosion rates are relatively high. Therefore, it is important to ensure that adequate monitoring procedures are in place to detect boric acid leakage before it results in significant degradation of the reactor coolant pressure boundary, such as wastage of CRDM holddown bolts.

7.4.7 Stress Relaxation. Many of the bolts in the reactor internals are stressed to a high initial cold preload. When subjected to higher temperatures over time, these bolts can loosen and the preload can be lost. Radiation can also cause stress relaxation in highly stressed members such as bolts. An initial cold preload of 138 MPa (20 ksi) will decrease to approximately 69 MPa (10 ksi) at 6×10^{19} nvt (>1 MeV).[52]

7.4.8 Transgranular SCC. In 1988, leaks were found on the canopy seal welds between the Diablo Canyon 1 reactor vessel head nozzle and CRDM plugs at several spare locations.[58] The leaks were attributed to transgranular stress corrosion cracking resulting from concentrations of chlorides and sulfates in the stagnant liquid in the canopy annulus, and in the crevices formed by the lack of weld penetration. The presence of chlorides and sulfates was verified from water obtained from water samples from the annulus. A further contributor could be the higher oxygen concentration in the annulus of the spares, because they are the high points in the system. The canopy seals were replaced by plugs with full penetration welds.

An isolated case of transgranular stress corrosion cracking was found in the CRDM motor tubes in the Palisades plant.[59] This appears to have been a problem with a particular lot of stainless steel, not a generic problem. However, this instance does serve to point out that given the right combination of material and environment, stress corrosion cracking is possible in a PWR.

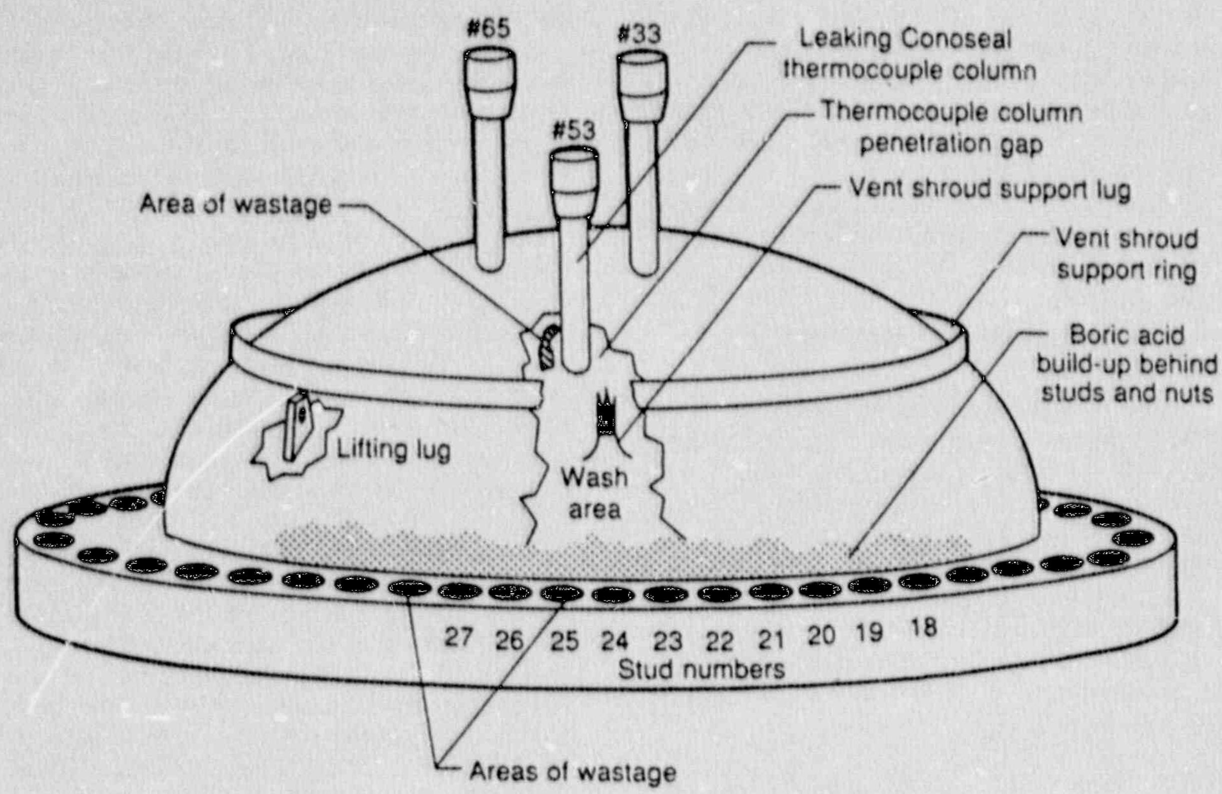

Figure 7.19. Areas on the reactor vessel head of Turkey Point 4 affected by boric acid.

7.4.9 Low-Cycle Fatigue. Thermal fatigue of the CRDM pressure housing should be considered. Metal fatigue is discussed in Section 3.4.1. However, in contrast to other heavily stressed components, the pressure housing is not subjected to particularly high temperatures, nor is it highly stressed. Consequently, a relatively low fatigue usage is predicted.[34,60] Also, reactor operating transients tend to be far less severe than the design transients used for the original fatigue calculations. Thus, it has been estimated that CRDM reactor coolant boundary lifetimes can be extended considerably past 40 years without exceeding the ASME Code fatigue limits.[5,34] Calculations for the H.B. Robinson 2 (Westinghouse) plant show the fatigue usage for the control rod housing as 0.034 and for the bottom instrumentation as 0.119. Both are far less than the allowable value of 1.00.

For the reactor internals, low-cycle fatigue may pose aging-related problems for the lower support plates and columns, the upper support plate, various bolts and pins, and guide tube welds. The various smaller components (such as irradiation specimen holders), the thermal shield and its bolts, and the upper support columns and bolts are considered to be more susceptible to high-cycle fatigue, caused primarily by flow-induced vibrations, as discussed above.

7.4.10 Electrical Malfunctions. This mechanism is, of course, applicable to CRDMs but not reactor internals. The primary concern in the electrical equipment is insulation breakdown in the stator or lift coils. Other areas of concern are aging of the trip breakers resulting in an inadvertent rod insertion caused by undervoltage. A number of outages in Babcock & Wilcox units have been caused by electrical shorts in the stator winding endturns. Babcock & Wilcox has identified four contributors to these failures: epoxy breakdown caused by incompatibility with the wire, moisture, bifilar design (side-by-side phasing), and manufacturing defects.[22] One such failure was caused by a CRDM vent leak that shorted out the stator (but was too small to pose a safety problem). Most frequently, these failures result in a dropped rod.

The Combustion Engineering Arkansas Nuclear 2 power plant experienced two lengthy outages caused by CRDM gripper coil failures.[14,15,22] Excess current applied to the coil caused the failures, which is primarily an operational problem. Most of the Combustion Engineering magnetic jack units have experienced failure with the 15-V dc power supply to the rod stepping logic, resulting in dropped rods. Two CRDMs at the Surry 1 nuclear plant have been instrumented at seven locations with thermocouples.[61] One use of the information they yield will be to determine the effect of temperature on coil over- temperature breakdown. Another use is to determine whether heat contributes to degradation of the rod position indicator cable connector.

7.5 Potential Failure Modes

The three CRDM failures of safety concern are CRDM pressure boundary rupture, pressure boundary leakage, and failure to insert control rods. In the worst-case scenario (pressure boundary rupture) a small-break loss-of-coolant accident could occur. However, the more likely failure results in a small leak of primary coolant, which is difficult to detect. The failure of the lower instrument tube seal on an in-core instrument tube would also cause a similar small leak of primary coolant. Coolant leakage can also result in boric acid corrosion.

Mechanical binding may prevent rod insertion. A failure of a single CRDM will reduce the safety margins that are built into the plant design but will not cause a major accident. PWR CRDMs are each completely independent. Therefore, it is very unlikely that a significant number of rods would become inoperable at the same time. The most common CRDM failure mode is a dropped rod. This is a recoverable event and is not a safety concern.

Westinghouse conducted a study of reactor trip rates (caused by various types of CRDM failures) versus the operating year in which the failures occurred.[4] The data base included information from 31 plants; however, only a few of the plants (<10) operated for more than ten years. The data appear to show that CRDM failures caused by problems with the pressure housings and electrical coil stack assemblies are generally random (not increasing with time). However, the CRDM failures caused by latch assembly problems, other than electrical coil stack assembly failures, and by drive rod assembly failures increased somewhat with time.

The failure mode for the reactor internals is generally a broken or dislocated part. These can have serious consequences on other reactor components. For example, loose bolts or other small subcomponents can become lodged in one or more CRAs or CRDMs and prevent rod insertion, resulting in reduced safety margins or reactivity accidents. Loose parts can cause binding, such as a loose breech guide screw in a Westinghouse unit that caused a stuck control rod in a foreign plant.[62] Small subcomponents can also be carried out of the reactor until finally they are stopped by the small openings in the steam generator tubes. For example, broken reactor internals caused considerable damage to the Crystal River 3 primary tube-to-tubesheet welds.

Loose reactor internals can cause flow diversions in the core, possibly leading to overtemperature conditions, and baffle jetting that may damage or dislocate fuel (such as the damaged fuel elements at the Trojan plant). Broken instrument housings in the bottom of the reactor vessel can cause serious unisolatable leaks. For instance, a January 1984 stainless steel thimble tube failure in the Zion Unit 1 Station, while the reactor was in a hot shutdown condition, led to a 0.001-m^3/s (18-gpm) leak to the containment.[25] A stainless steel thimble tube broke loose during a brush-cleaning operation at the Sequoyah Unit 1 plant in April 1984 while it was operating at 30% power, ejecting the entire thimble tube and cleaning equipment from the core. A leak rate of 0.002 m^3/s (30 gpm) continued for approximately 11 hours until the reactor could be cooled and the water level reduced below the break. By this time, approximately 60.6 m^3 (16,000 gallons) of reactor coolant had leaked into the containment.[25] Although makeup water can be supplied at this leak rate with no difficulty and no serious operational transients occurred as a result of the Sequoyah leak, expensive radioactive cleanup was required. The safety concerns associated with broken split pins are (a) misalignment of the control rod guide tubes, which can prevent rod insertions, and (b) loose parts, which can affect movement of a control rod or damage steam generator tube ends. Westinghouse has analyzed these two possibilities and has concluded that the potential for misalignment is not a safety concern, and that damage from loose parts is extremely remote.[63] However, a broken leaf spring that lodged in a CRDM caused a lengthy outage at the Davis-Besse 1 plant.[14, 22]

7.6 Inservice Inspection and Surveillance Requirements

The ASME formal guidelines for inspection of the CRDM housing welds are listed in Table IWB-2500-1, Item B14.10, of Reference 64. This standard calls for volumetric or surface inspection of 10% of the peripheral CRDM housings during each inspection period. Interior CRDM housing welds are generally inaccessible for inspection. Seal welds are not required to be inspected, though a check for leakage is made during hydrostatic tests. Visual inspection of CRDM bolts, studs, and nuts is also required. However, there are no formal guidelines for inservice inspection of the internal CRDM components, though inspections may be required by individual plant technical specifications. For example, the Combustion Engineering rack-and-pinion CRDMs are inspected for wear at specified intervals, but the Combustion Engineering magnetic jack CRDMs have no such requirement.

Electrical checks can be performed to determine stator current and insulation resistance. The torque or power required per step or rotation can give an indication of internal binding in the mechanism. To give a better indication of the state of the internal mechanism components, the drive rod assemblies can be pulled periodically from the core and inspected for wear. After inspections, the individual CRDMs can be rotated to different locations to allow for even wear. This could assist in establishing even wear over all CRDMs. The CRDMs are grouped in banks (for example, control or shutdown) that are arranged in a certain pattern based on core physics considerations. The CRDM wear in the banks differ, depending on the frequency of rod movement required for each bank.

There are several methods of monitoring for broken reactor internals during operation. One is the Loose Part Monitoring Systems (LPMSs) that have been required on reactors licensed since 1975.[65] These are acoustic systems, which detect the increased noise associated with a loose part rattling. Not only do they give an indication that there is a loose part, but generally point out the locations of increased noise. However, the location of the initial failure is not necessarily known until the reactor is shut down and inspected, because a broken part may travel to a new location such as a steam generator and cause increased noise (and additional damage) there. A second method of monitoring for broken reactor internals is evaluation of changes in the neutron flux monitor signals caused by reduced stiffness of the reactor internals.[31,32,66] These instruments are located both inside and outside the core and can detect changes in reactor internals structural frequencies. This technique requires a considerable amount of expertise, however, since other factors can also change the neutron noise signals. An effective method to separate the various influences is required. It is also desirable to use a structural model of the reactor internals in conjunction with this technique. A specific use of this technique for monitoring core barrel motion has been included in an ASME standard.[67] A third continuous monitoring scheme is to place accelerometers at strategic locations on the reactor internals and review the signals for significant changes. This method could be expensive and the results may be suspect, since these devices are degraded by radiation, and the signals could be distorted by unwanted vibration sources some distance away.

Table IWB-2500-1, Item B13.40, of Reference 64 requires visual inspection of accessible, removable core support structure surfaces. The structure must be removed from the RPV for examination at each inspection interval. Visual inspection of accessible welds of integrally welded core support structures and accessible surfaces are also required to determine degraded areas and the nature of the deterioration. These give a good overall view, which can pinpoint locations for more detailed examinations. However, in many cases, visual examination of exposed surfaces cannot predict locations of impending failures. Inspection of the reactor internals is especially difficult because of the high radiation fields in this area.

There are two categories of visual inspection: VT-1 and VT-3. VT-1 determines the specific condition of a part, component, or surface for such conditions as cracks, wear, corrosion, erosion, or physical damage. For proper examination there must be sufficient access to allow the eye to be within 610 mm (24 inches) of the surface and at an angle not less than 30° to the surface.[68] Mirrors can be used to improve the angle of vision. Lighting must be sufficient to resolve a 0.79-mm (1/32-in.) line on an 18% neutral gray card. Section XI of the ASME Code also allows remote VT-1 examinations, but the remote systems must have a resolution capability as good as obtainable by direct visual inspection.

A VT-3 examination can determine the general mechanical and structural conditions of components and their supports, verifying clearances and settings, identifying loose or missing parts, debris, corrosion, wear, and erosion.

Typically, VT-1 and VT-3 inservice inspections have been performed using underwater cameras suspended from the refueling deck, as much as 22.7 m (75 ft) above the reactor internals. A remotely operated vehicle equipped with cameras and lights has also been developed.[68]

Ultrasonic testing (UT) is mostly used for volumetric inspections to detect subsurface cracks, local thinning, or other anomalies internal to the subcomponent. Other methods, such as dye penetrant inspections, radiographic techniques, magnetic particle testing, and eddy current testing, can sometimes also be used on selected components. One difficulty in detecting bolt degradation, which is probably the most common reactor internals degradation, is that the bolts are, for the most part, surrounded by the metal components that they join, and, therefore, mainly inaccessible. Also, the critical crack size in a bolt (the minimum length where the crack can propagate rapidly through the entire cross-section) is often very small, only 1 to 2 mm in length in small bolts.[69] EDF has developed an UT method called REBUS to inspect split pins.[41]

NRC Bulletin 88-09 requires that each Westinghouse plant licensee with bottom-mounted instrumentation establish a program to monitor thimble tube performance, including criteria for acceptable wear, inspection frequency, and inspection methods.[70] In response to Bulletin 88-09, Virginia Power stated that the Surry design is a unique double-walled configuration (see Figure 7.20) that provides an added level of protection against leakage.[71] An inspection methodology and criteria for the double-walled configuration are being developed. In Reference 72, Duke Power stated that McGuire 1 thimble tubes showed little degradation, with only two indicating any detectable wall loss. The maximum detected loss was 30% of one tube at the top of the lower core plate (see Figure 7.17). The other wear indication was 17% wall loss at the vessel penetration. Westinghouse has developed a program to perform eddy-current inspection of flux thimble tubes to confirm their integrity. The inspection is performed after refueling and while the reactor coolant system is depressurized.[73]

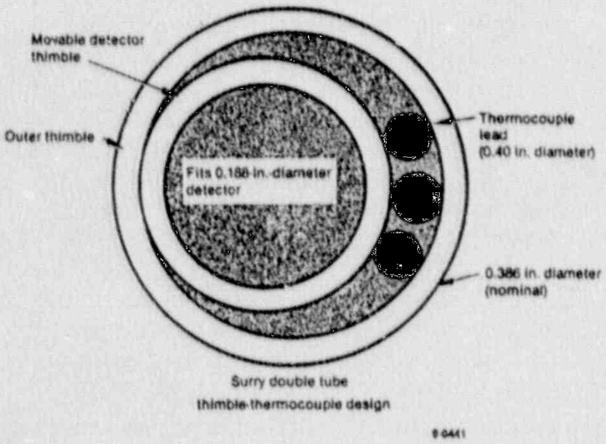

Figure 7.20. Surry double tube design.

The Electric Power Research Institute (EPRI) is sponsoring the development of advanced UT methods for bolt inspections.[69] As a result of EPRI Project 2179-2, Southwest Research Institute (SwRI) has developed the cylindrically guided wave technique (CGWT).[74] The SwRI program evaluated the CGWT on a wide variety of stud bolts (lengths and diameters) to determine the minimum detectable crack size, evaluated signature analysis techniques for increasing the sensitivity of the CGWT, trained field inspection personnel, developed an inspection procedure, and assisted in the initial field use of the CGWT. However, there needs to be extensive field verification of the technique to determine whether it is practical to use the CGWT to detect bolt degradation in the high-radiation areas of difficult-to-access bolts in the reactor internals.

7.7 Summary, Conclusions, and Recommendations

Many of the factors relating to lifetime predictions of CRDMs are unknown. While fatigue usage of pressure housings can be calculated, there are still many subcomponents for which no suitable lifetime prediction information is available. These include the insulation breakdown of the electrical components and wear of the latching mechanisms. We know CRDMs have generally operated successfully for a number of years (over 20 years at some Westinghouse-designed plants and over 15 years at some Combustion Engineering plants), but there is not enough information at present to predict the overall lifetime. Lifetime tests show that Combustion Engineering CRDMs can probably operate for a minimum of 30,480 m (100,000 ft) of travel,[a] and Westinghouse reports a lifetime in excess of 2.5 million steps, but we do not have the statistical data base from CRDM fragility tests to satisfactorily compute the probabilities needed to predict the expected life. Both Combustion Engineering and Westinghouse attribute the operating problems experienced to date to random malfunctions and not to aging factors, although some types of CRDM failures have been increasing with time. Combustion Engineering expects the motor assembly and drive shaft to experience the greatest wear or fatigue.

Based on the information available to date, the critical locations with respect to plant aging are listed in Table 7.3. The potential failure locations that can result in primary coolant leakage are ranked highest.

There are several activities that should be conducted to extend our knowledge of CRDM aging related issues. These include the following:

1. Ten percent of the peripheral CRDM housing welds are inspected during each inservice

a. C. W. Ruoss, private communication, Combustion Engineering, February 3, 1987.

Table 7.3. Summary of degradation processes for PWR CRDMS

Rank	Degradation Sites	Stressors	Degradation Mechanisms	Potential Failure Modes	ISI Methods
1	Pressure housing	Thermal stress, high-temperature water	Thermal embrittlement, low-cycle fatigue	Crack leading to leak	Volumetric or surface[a]
2	Latch assembly	Loose parts, impacting, metal-to-metal contact	Fretting, wear, spalling	Binding, stuck rods	None
3	Coil stack	Moisture, temperature, radiation	Insulation breakdown, electrical shorting	Dropped rods	None
4	Drive rod	Rubbing, impacting	Wear, low cycle fatigue	Uncoupling of CRA	None
5	External components	Boric acid (if leak is present)	Boric acid corrosion	Leaks	None

a. 10% of peripheral CRDMs per inspection interval.

inspection interval, but the welds of the interior CRDMs are generally inaccessible and not inspected. Techniques should be developed to ascertain the integrity of the welds that are inaccessible for inspection.

2. Adequate monitoring techniques are needed to detect boric acid leakage before it causes significant corrosion of the primary coolant pressure boundary. Leaking borated coolant from a CRDM or instrument housing can cause corrosion of the external CRDM components and the vessel carbon steel base metal.

3. Evaluation of the thermal embrittlement of cast stainless steel CRDM pressure housings is needed.

4. The electrical parameters (for example, the current required) which indicate the degree of wear, friction, or binding in CRDM should be measured periodically.

5. Techniques for measuring the cumulative length of lead screw travel or counting the number of latch steps should be developed. This information should be recorded and could then be compared to the CRDM life test results to determine the need for CRDM replacement.

6. The CRDMs should be periodically pulled and inspected for excessive wear. After inspection they could be rotated to different rod banks to allow for more even wear. Careful measurements of the wear would facilitate better residual life estimates.

7. Life tests for the latch assemblies (roller nut, rack-and-pinion, and magnetic jack) and the electrical insulation are needed. If the lifetimes are found to be insufficient, alternate materials with extended lifetimes could be considered. Vendor tests have shown that CRDMs are suitable for the estimated travel required for 40 years, but have not established absolute lifetimes in feet of travel for all designs.

One major advantage to CRDM life extension is that many of the subcomponents can be replaced relatively easily. This is especially true of the electrical components, which are located outside of the pressure housing. The technology for CRDM replacement is available, as full changeouts have been made.

The critical locations with respect to reactor internals aging in order of importance are listed in Table 7.4. These generally are concerned with bolts and other smaller parts loosening or breaking, and larger components cracking or undergoing excessive vibration. Some recommendations with respect to the reactor internals are as follows:

1. Monitor the wear of the in-core instrument housings (including the thimble tubes) and CRDM guide tubes.

2. Develop advanced inservice inspection procedures that can predict incipient failures. Such a technique for bolts is particularly needed.

Table 7.4. Summary of degradation process for PWR reactor internals

Rank	Degradation Sites	Stressors	Degradation Mechanisms	Potential Failure Modes	ISI Methods
1	Instrument tubes (Thimble tubes)	Flow-induced vibration, high-temperature water	Fretting, high-cycle fatigue, wear	Leaks, cracks, loose parts	Eddy-current
2	Thermal shield and bolts	Flow-induced vibration, high-temperature water, bolt preload stress, radiation	High-cycle fatigue, IGSCC, stress relaxation	Broken bolts, cracks, loose parts	Visual[a]
3	Core barrel and bolts	Flow-induced vibration, high-temperature water, bolt preload stress, radiation	High-cycle fatigue, IGSCC, stress relaxation	Broken bolts, cracks, loose parts	Visual[a]
4	Upper and lower core support structures	Flow-induced vibration, high-temperature water, bolt preload stress, radiation	High-cycle fatigue, IGSCC, stress relaxation, irradiation and thermal embrittlement	Broken bolts, cracks, loose parts	Visual[a]

a. Accessible surfaces of removable components and welds of integrally welded components.

3. Develop high-cycle fatigue curves for high-strength steel bolting materials.

4. Establish research programs to determine the combined effect of radiation and temperature, causing embrittlement of austenite and ferrite phases, respectively, in the cast stainless steel components.

5. Establish research programs to determine the effect of radiation and cumulative fluence on the mechanical properties of reactor internal materials. Tests of actual core specimens would be helpful.

6. Perform an alternate material study to develop bolts and pins with extended lifetimes. This would include different heat treatments of Alloy X-750, Alloy 718, and Alloy A-286.

7. Establish vibration monitoring programs using the ex-core and/or in-core neutron noise detectors in conjunction with other monitoring instruments and structural finite element models.

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8. COUNTERMEASURES FOR TUBE FAILURES IN PRESSURIZED WATER REACTOR STEAM GENERATORS

A. S. Amar

8.1 Introduction

The pressurized water reactor (PWR) steam generator tubes form well over one-half of the primary system pressure boundary and have experienced significant aging degradation at some plants.[1] Tube failures have allowed the primary coolant a means of contaminating the secondary coolant and have caused radiological releases to the environment when the atmospheric relief valves were actuated. Degraded steam generator tubes may fail during a severe accident and allow radioactive material to bypass the containment. The simultaneous rupture of several tubes may lead to a major plant temperature and pressure transient with a potential impact on the structural integrity of various components in the system. Tube leakages result in unscheduled plant outages when the leakage rate exceeds the acceptable limits. It is estimated that about 25% of unscheduled plant outages in PWRs are caused by steam generator problems.[2] Numerous plant shutdowns cause an increased number of fatigue loading cycles on various plant components. Finally, the repair and replacement activities associated with steam generators have accounted for much of the personnel radiation exposure (manrems) at PWR plants. Figure 8.1 shows that the steam generator repair problems accounted for a significant portion of the loss of availability and personnel radiation exposure at one PWR plant.[3]

The useful life of many PWR steam generators may end much sooner than the end of the plant license period because of tube degradation. Consequently, life extension issues for steam generators may arise sooner than the end of the forty-year plant license period.

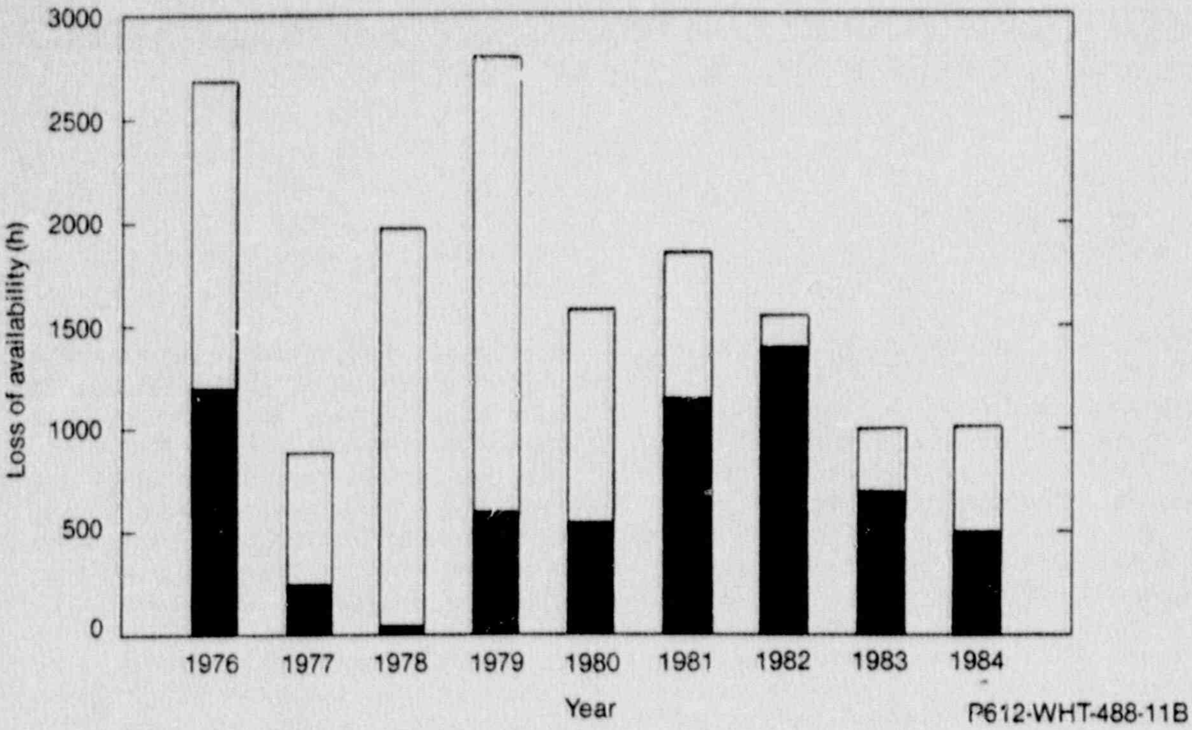
The safety concerns related to the tube degradation problem are as follows: (a) ensuring primary boundary integrity by maintaining margins against tube failures [using conservative acceptance standards for the nondestructive examination (NDE) indications], (b) developing criteria for qualifying the repair/replacement processes and procedures that will ensure *long-term* effectiveness, (c) licensing the design and material modifications needed for mitigating steam generator tube degradation, and (d) minimizing the radiation exposure resulting from the inspection and mitigation activities.

The industry has developed various steam generator tube failure countermeasures. These include (a) plant operation and maintenance techniques for preventing or reducing further degradation of the existing tubing, (b) plugging and sleeving of failed tubing, and (c) technology for in situ retubing, replacing the lower assemblies of a steam generator, or replacing the entire steam generator when the failed tubes are too numerous to economically justify plugging or sleeving. This chapter describes the current industry approaches for coping with PWR steam generator tube failures and evaluates their effectiveness. (A life assessment procedure for steam generator tubes is presented in another NPAR project report. This procedure quantifies the damage resulting from the different degradation mechanisms and accounts for the mitigating effects of the countermeasures.)

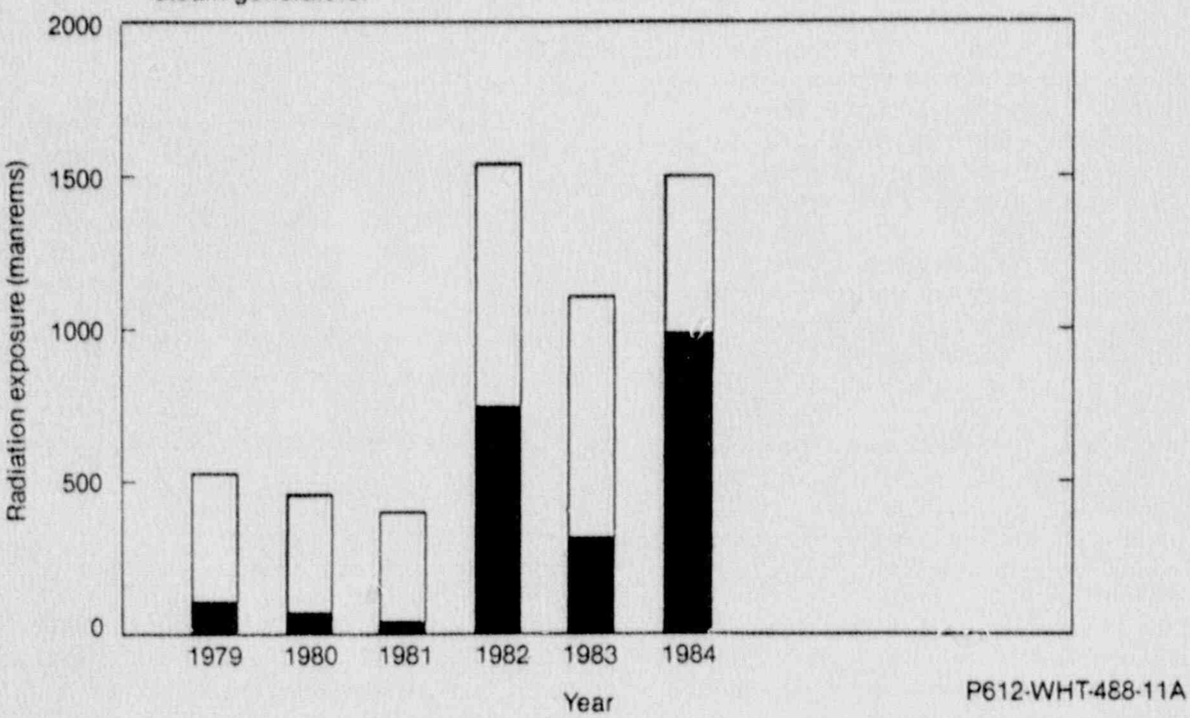
This chapter is organized as follows: steam generator tube degradation mechanisms are identified, the laboratory studies and field observations that have led to the current understanding of the role of water chemistry and the metallurgical condition of the tubing are discussed, the mitigation techniques and repair and replacement approaches developed by the industry are evaluated, and a summary with conclusions and recommendations is presented.

8.2 History of Steam Generator Tube Degradation

There are two types of PWR steam generators: the recirculating type using U-bend tubing with one tubesheet (Westinghouse and Combustion Engineering), and the once-through steam generators (OTSGs) using straight tubes with two tubesheets (B&W). CANDU-pressurized heavy water reactors (Canada) also use recirculating type steam generators.[2] A detailed discussion of the mechanisms and degradation in various designs of steam generators is given in Volume 1 of this report.[5] The description in this section is brief because it is intended to provide only background information for the discussion of countermeasures in later sections.



(a) Total loss of availability per year. The shadowed portion is due to steam generators.



(b) Total radiation exposure of personnel per year. The shadowed portion is due to steam generators.

Figure 6.1. Problems associated with steam generator failures.[3]

8.2.1 Secondary Side Degradation in U-Tubes. The secondary-side degradation mechanisms that affect the Alloy 600 tubing in the recirculating type steam generators are listed below:

- *Intergranular Stress Corrosion Cracking (IGSCC)* results in cracks oriented normal to the maximum principal stress. It is caused by the combined action of the environment, stress, and material susceptibility.

- *Intergranular Attack (IGA)* is a corrosion process resulting in a localized loss of metal along the grain boundaries. Unlike IGSCC, it does not require stress, and the geometry of the attack is not stress-oriented.

- *Pitting* is a local corrosive attack. The metal loss may eventually lead to a small-diameter hole in the tube. It can occur as a single pit or as a cluster of pits in a band.

- *Wastage* is tube thinning resulting from the loss of metal by general corrosion. The extent of thinning may or may not be uniform on the tube surface, but it is not localized like pitting.

- *Denting* is a constriction in the tube caused by plastic deformation. Denting is caused by the volumetric expansion involved in the oxidation of the tube-support material that closes the clearance between the tube and the tube-support plate.

- *Fretting* is a loss of tube metal (wear) as flow-induced vibrations cause excessive rubbing of tubes against their support structures. It makes the tubes susceptible to fatigue-crack initiation at stresses well below the fatigue limit.

- *High-Cycle Fatigue* is caused by high-amplitude, flow-induced vibrations. High-Cycle fatigue was responsible for the rapid, circumferential tube break in Virginia Power's North Anna 1 unit.[a]

- *Low-Cycle Fatigue* affects the dented tubes during thermal transients, including heatups and cooldowns.

Until the late seventies, PWR secondary water chemistry was based on coordinated phosphate additions to provide a buffering system. A buffered solution can accommodate the addition of moderate amounts of acid or base without a marked change in its hydrogen-ion concentration. Acid- or caustic-producing impurities present in small quantities react with the buffering agent (the phosphate) and the resulting precipitates are supposed to be removed via a blowdown.[6] The buffered solutions automatically maintain their pH value. However, phosphate chemistry can provide buffering only against the ingress of small quantities of impurities. Phosphate chemistry is ineffective when large quantities of impurities are introduced during events such as a condenser in-leakage. Also, phosphate chemistry results in a concentration of chemicals in a sludge pile on the tubing outside surfaces, which in turn causes general corrosion of the tubing. The resulting wastage requires plugging of the tubes when the wall thicknesses are reduced by 40 to 60% of the original values. After several laboratory studies and field observations, almost all PWRs have now been switched from phosphate chemistry to an all volatile treatment (AVT) to mitigate the steam generator tube wastage problem.

An AVT uses low molecular weight amines, for example, hydrazine or ammonium hydroxide, which thermally decompose under normal steam generator conditions to produce ammonia, nitrogen, and hydrogen. The ammonia elevates the pH to minimize carbon steel corrosion and because of its volatility leaves the steam generator with the steam going to the turbine without leaving any residues or deposits on the tubes. Hence, continuous additions of hydrazine or ammonium hydroxide, or both, are required to maintain the pH. Because an AVT does not buffer the system, the water chemistry needs to be constantly monitored and corrected. The water chemistry control guidelines developed by the Steam Generator Owners' Group require the constant monitoring of cation conductivity, chloride, sodium, pH, ammonia, dissolved oxygen, hydrazine, copper, iron, and silica.[7,8] The Steam Generator Owners' Group guidelines also establish very low levels of acceptability for impurities because the water chemistry at an AVT plant is more sensitive to small quantities of impurities than is the water chemistry at a plant using phosphate.

It is difficult to control the water chemistry in an AVT system in the event of faulted conditions. Some common faulted conditions are (a) in-leakage of brackish or sea water from the condenser, (b) impurities in the feedwater, (c) impurities released from the condensate polishers in normal operation, and (d) resins released by the condensate polishers because of

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a. North Anna Unit 1 Steam Generator Tube Rupture, July 15, 1987, ACRS Meeting, December 15, 1987.

misoperation or mechanical damage.[6] The condensate demineralization system is used in some plants to remove both ionic and organic acid impurities.[9] If the system is operated close to or past the point of resin exhaustion, some soluble species may be released from the resin and the impurities returned to the steam generator. This is called slippage. High flow rates through the resin also ca[illegible] slippage.[6] Some of the ionic impurities fou[illegible] secondary water at various plants are Na^+, [illegible]SO_4^-, CO_3^-, Fe^{++}, Cu^{++}, and Ni^{++}.[a] In addition, the following organic acid impurities were detected in a survey of 14 different utilities: acetic acid, formic acid, lactic acid, propionic acid, and butyric acid.[10]

With the switch from phosphate chemistry to an AVT, the phosphate wastage problem has been controlled, but transient AVT chemistry conditions sometimes result in various other degradation mechanisms. (Wastage in the cold-leg side of the U-tube from sulphate corrosion is not mitigated by this change.[a]) The first problem that appeared after the change was denting.[1] Acid chlorides concentrate in the tube support annuli during transient AVT conditions, and enhance the oxidation of the carbon steel support structures.[11] Magnetite (the product of oxidation) fills the clearance between the tube and tube-support plate and causes denting. Magnetite formed in the presence of acid chlorides is porous and, therefore, does not retard further oxidation. This contributes to further denting. Laboratory studies indicate that prior operation using a coordinated phosphate treatment is not a precursor to denting.[6] In fact, the residual phosphates, if present in the tube support annuli, could provide buffering and neutralize the acidic chlorides that enhance the support plate oxidation. There is a strong direct relationship between the chloride content and the denting rate.[6,12] Also, copper and copper oxides are transported to the annuli and they enhance the formation of magnetite.

Pitting of Alloy 600 steam generator tubing is also attributed to the presence of chlorides, oxygen, and copper. However, only shallow pitting has been reported in most plants[5] except Indian Point 3 and Millstone 2. But the uncertainties in NDE may result in an underestimation of the extent of pitting. The presence of copper containing sludge introduces noise in eddy current signals, and many pits may remain undetected because of this noise. For example, reinspection indicated more pits at Millstone 2 after chemical cleaning of the residual sludge on the tube surfaces.[b]

Fewer numbers of steam-generator-tube failures attributed to denting and pitting are now being reported (see Reference 1). This is the result of the various corrective actions taken by the utilities, such as preventing condenser in-leakage, maintaining acid chlorides below 20 ppb during blowdown,[8,11] eliminating copper alloys from the feed train, sludge lancing, using boric acid, reducing the oxygen in the condensate storage tank, and using deep-bed polishers. These measures were taken while precluding the problems from resin ingress (discussed in Section 8.2.2).

The steam generator-tube-degradation mechanisms of current concern, IGA and IGSCC, usually occur close to each other, the IGA being more extensive. IGA/IGSCC on the secondary side tube surfaces has been reported in the region of the tubesheet crevices and tube-support annuli. Failure analysis of tubes removed from various plants indicates the presence of sodium, potassium, calcium, phosphorus, sulfur, aluminum, and chlorides near the failed (IGA) regions.[13] Failure analysis of tubes from the St. Lucie Unit 1 plant also indicated the presence of iron, copper, lead, zinc, magnesium, and silicon on corroded grain boundaries.[14] However, this does not indicate a mechanistic relationship between these elements and the failures. Laboratory studies indicate that IGA/IGSCC does not occur unless the coolant is very caustic (a pH above ten).[15] The overall water chemistry never reaches such severe caustic levels, even during highly transient conditions. The only plausible explanation for the field failures is that the caustic impurities concentrate in the crevices during plant operation and increase the local pH. It is not fully established whether local pH values less than 10 will preclude IGA/IGSCC under all field conditions. Acidic sulphates also produce IGSCC/IGA. However, it is clear that the remedies lie in eliminating the crevices, minimizing the crevice acidic impurities, flushing the crevices, and neutralizing the crevice alkalinity. These remedies are discussed in Section 8.3.

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a. John F. Hall and W. R. Gahwiller, private communication, Combustion Engineering, 1987.

b. M. F. Ahern, private communication, Northeast Utilities Service Company, 1987.

Certain Westinghouse and Combustion Engineering PWR steam generator designs are susceptible to the type of high-cycle fatigue damage that resulted in the tube rupture at the North Anna Unit 1 plant. These designs have a high recirculation flow factor, and, therefore, the tubes in the U-bend region above the top support plate are exposed to strong cross flows and flow-induced vibrations. The flow-induced vibrations can be sufficient to cause tube failure shortly after a crack appears if the tube is dented.[16,17] The failed tube at the North Anna Unit 1 plant was dented and not supported by the antivibration bar. The denting resulted in reduced damping of the tube vibrations and in a high mean stress, significantly reducing the fatigue strength.[18,a] The combination of high vibration amplitude (caused by fluid-elastic instability) and low fatigue strength led to the fatigue failure. Tube rupture high up in the steam generator results in a leak location that can easily become uncovered by secondary water. This can allow escape of the fission products from the primary coolant without partitioning in the secondary water and is, therefore, a safety concern. The North Anna Unit 1 crack apparently propagated to a double-ended guillotine break in about 12 to 48 hours. Such rapid failures are not detectable by eddy current testing. One possible way to prevent such failures is to reduce the local fluid forces, and flow resistance plates have been installed in the North Anna downcomer to reduce the fluid forces.

Fretting damage from flow-induced vibrations can be (and has been) eliminated by changing the design of the antivibration bars to provide a broader region of contact with the tube (rather than the previous point contact design).

8.2.2 Primary Side Degradation of U-Tubes. Pure-water (or primary-water) stress corrosion cracking (PWSCC) is the only degradation mechanism active on the inside surface of PWR steam generator tubes. The IGSCC/IGA of the secondary side and the PWSCC together account for 70% of the tubes plugged in the years 1983 to 1984.[1] Mechanical damage from loose parts impinging on the bottom of the tubesheet also required tube repairs in some plants.

There are no crevices, no concentrations of impurities, and no caustic environments on the primary side; therefore, there is no IGSCC/IGA on the tube inside surfaces. PWSCC has occurred in the high-stressed tube regions, namely, (a) the rolled tubesheet joint, (b) the U-bend locations with a sharp radius, and (c) dented regions, suggesting that a tensile residual stress is a necessary condition for PWSCC. The residual stresses at the tubesheet and the U-bends depend on the geometry of the transition between the plastically deformed regions and the undeformed tube, and also on the deformation processes used. Laboratory studies indicate that the residual stresses are usually close to the yield strength of the tube material. There is no nondestructive field inspection technique that can be used to quantify the residual stresses in these regions.

The residual stresses also depend on the yield strength of the material. A high-yield-strength material requires larger forces for deformation and, therefore, is left with larger residual stresses, perhaps above the threshold for PWSCC at the plant temperatures.[19] It has been suggested that PWSCC-prone material has a yield strength above about 380 MPa (55 ksi), a fine grain size (ASTM 9-11), intragranular carbides (no carbides on the grain boundaries), and little or no solid-solution carbon.[20] This postulation is based on failure analysis characterizations and laboratory studies on simulated Alloy 600 microstructures.

A material with a yield strength below 380 MPa (55 ksi) and with grain boundary carbides precipitated after a sufficiently high final anneal temperature is postulated to have high PWSCC resistance. ASME Code Specification SB-163 for Alloy 600 steam generator tubing requires a minimum yield strength, but sets no maximum limit. The Combustion Engineering steam generators were fabricated with tubing with a maximum yield strength of about 380 MPa (55 ksi). Because such a specification can be met only if the final anneal is at a sufficiently high temperature, the carbides will be dissolved and reprecipitated on the grain boundaries, which provides the PWSCC resistant microstructure postulated in Reference 20. However, such microstructures are susceptible to secondary side IGA/IGSCC because the grain boundaries become chromium depleted (sensitized) during the high temperature anneal and that has occurred in some Combustion Engineering steam generators (no PWSCC has yet occurred in any of the Combustion Engineering plants.[19,20] Thermally treated Alloy 600 also has grain boundary carbides in its microstructure, except that it will be resistant to both the primary and secondary side IGSCC because there is no chromium-depleted regions (sensitization). Thermally treated Alloy 600 also has a yield strength below the

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a. North Anna Unit 1 Steam Generator Tube Rupture, July 15, 1987, ACRS Meeting, December 15, 1987.

postulated 380 MPa (55 ksi) limit.[a] Thermally treated Alloy 690 with its higher chromium content than Alloy 600 appears to be, by consensus, the current choice for future steam generator tubing because of its superior resistance to PWSCC, as well as secondary side IGA/IGSCC.[21] Chemical compositions of Alloys 600 and 690 are given in Table 8.1. The average grain size of Alloy 600 is in the range of 7.8 to 10.0 μm and the Alloy 690 grain size is in the range of 17 to 41 μm. The yield strengths of these alloys are inversely proportional to their grain sizes.[22]

8.2.3 Degradation in Once-Through Steam Generators. Once-through steam generators (OTSGs) use the same Alloy 600 tubing materials as recirculating steam generators, yet the OTSGs have experienced significantly fewer tube failures. The lower failure rate is attributed to the differences in the steam generator design, manufacturing processes, and operation. Many of the chemical concentration processes do not operate in OTSGs, as they do in recirculating steam generators.[b] The OTSGs are stress-relieved as a unit. Therefore, any residual stresses that cause PWSCC are removed. Phosphate chemistry has never been used in most OTSGs, so phosphate wastage has never been a problem. All OSTGs use AVT water chemistry. However, the once-through design is susceptible to sludge buildup around the lower support plate flow holes that restrict the feedwater flow. Such flow restriction has forced some Babcock & Wilcox plants to derate by as much as 30% at times.[23] The sludge can be removed by a mechanical process called waterslap, which is discussed in Section 8.3.3.

In addition, erosion-corrosion has reduced wall thicknesses by more than 40% in the tubes around the fourteenth support plate in some OTSGs. Because the damage can be self accelerating, plugging is recommended if this mechanism is known to be operative. Environmental fatigue caused by dry out of impinging water droplets on the tubes around the open lane has also caused cracking and leakage in several tubes.[6] The OTSG tubes also experience corrosion fatigue attributed to vibrational stresses and differences in the thermal expansion of the tubing and shells. Because the principal stresses in OSTG tube are axial, circumferential cracks are found in OTSGs (unlike the axial cracks caused by the hoop stresses in the recirculating type steam generators).[24]

8.2.4 Degradation Mechanisms. The PWR steam generator tube-degradation sites, stressors, and degradation mechanisms are summarized in Table 8.2. Several laboratory studies have been performed to

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a. The thermally treated tubes have been heated in a vacuum to 1300°F for about 12 hours.

b. A. P. L. Turner, private communication (V. N. Shah), Dominion Engineering Company, 1988.

Table 8.1 Chemical composition of the PWR steam generator tube materials[22]

	Chemical Composition, wt%	
	Alloy 600	Alloy 690
Carbon	0.10 maximum	0.05 maximum
Manganese	0.10–1.0	0.5 maximum
Iron	6.0–10.0	7.0–11.0
Chromium	14.0–17.0	28.0–31.0
Aluminum	0.05–0.35	0.05–0.40
Titanium	0.10–0.50	0.10–0.50
Cobalt	0.1 maximum	0.1 maximum
Nickel	Essentially balance (72.9 min)	Essentially balance (58.0 min)

Table 8.2. Summary of degradation processes for steam generator tubes

Rank[a]	Degradation Site	Stressors	Degradation Mechanisms	Potential Failure Modes	ISI Method
1	Inside surface of U–bends, roll–transition, and dented tube regions	Tube rolling and U–bend stresses, primary coolant, and residual stresses introduced by denting	Pure water stress corrosion cracking	Cracking, leakage	Eddy–current testing
2	Outside surface of hot–leg tubes in the tube–to–tubesheet crevice region	Alkaline environment, presence of SO_4 and CO_3 anions	Intergranular stress corrosion cracking, intergranular attack	May eventually result in cracking	Eddy–current testing
3	Cold–leg side in sludge pile or where scale containing copper deposits is found	Brackish water, chlorides, oxygen, and copper	Pitting	Local attack and tube thinning may eventually lead to a hole	Eddy–current testing, optical scanner system, sonic leak detector system
4	Outside surface of tubing above tubesheet	Phosphate chemistry, chloride concentration, resin leakage from condensate polisher bed	Wastage (thinning)	Uniform attack, tube thinning may eventually wear out the material	Eddy–current testing
5	Tubes in the tube–support regions	Oxygen, copper oxide, chloride, temperature, pH, crevice conditions	Denting	Flow blockage in tubes caused by plastic deformation	Helium leak and sonic leak testing, optical probes, hydrogen evaluation monitoring, pulse–echo ultrasound method
6	Contact points between tube and antivibration bar	Flow–induced vibrations	Fretting	Wearing out of material caused by rubbing and/or fatigue	Eddy–current testing

Table 8.2. (continued)

Rank[a]	Degradation Site	Stressors	Degradation Mechanisms	Potential Failure Modes	ISI Method
7	Inadequately supported tube near upper support plate	Residual stresses and reduced damping caused by denting, flow–induced vibrations	High–cycle fatigue	Tube rupture (double–ended guillotine break)	Eddy–current testing
8	Tubes where denting has occurred	Thermal transients	Low–cycle fatigue	Primary–to–secondary leaks	Eddy–current testing
9[b]	Once–through steam generator tubes	Velocities, sizes, shapes, impact angle, and hardness of particles, thermal transients	Erosion–corrosion from impingement of particles, low–cycle fatigue	Wearing out of material, primary–to–secondary leaks	Eddy–current testing
10[b]	Once–through steam generator tubes in the upper (tubesheet) region	Chemicals (localized corrosion), vibrations	Fatigue	Primary–to–secondary leaks	Eddy–current testing

a. Based on operating experience for steam generator defects.

b. Denotes once–through steam generator (items 7 and 8 do not reflect rank order). First 6 items are for recirculating steam generators.

understand these degradation mechanisms. However, long initiation times (several years) and peculiarities of field conditions (such as the transportation and concentration of chemical impurities in certain regions of the steam generators) make it difficult to extrapolate laboratory results to field conditions. Similarly, the differences in plant configurations, designs, and materials, as well as the variations in the the makeup water impurities at the various plants (depending upon the ecology of the plant site), make it difficult to generalize conclusions from field observations. Therefore, research continues on understanding the degradation mechanisms.

The tubes are in fact exposed to the following environments in the steam generators: (a) primary water; (b) secondary water with AVT chemistry; (c) chemical impurities in the sludge pile, tubesheet crevices, and tube supports; and (d) various types of secondary water chemistry transient conditions.

The secondary-side failure mechanisms (denting, pitting, IGA, and IGSCC) are generally attributed to concentrations of impurities and faulted conditions. Therefore, efforts in controlling secondary side water impurities, preventing transient chemistry conditions, and removing chemical impurities are given high priority at PWR plants.

Alloy 600 is prone to stress corrosion cracking when highly stressed in high-purity nuclear reactor water (sometimes called Coriou cracking).[25] It does not require the presence of impurities in the water but may be enhanced by them. Apart from PWSCC, Alloy 600 is also prone to caustic- and sulfur-species-induced IGSCC.

Alloy 600 is also prone to sensitization and then secondary side IGSCC caused by certain faulted-water chemistry conditions. Significant grain boundary chromium depletion (GBCD) will cause sensitization of Alloy 600. However, the presence of carbides on the grain boundaries by itself may not indicate sensitization. Depending on the chromium and carbon contents, the heat treatment, and several other variables, it is possible to have grain boundary carbides without significant GBCD. Thermally treated Inconel 600 with grain boundary carbides and without GBCD is resistant to IGSCC on both the primary and secondary sides. Even if GBCD has actually occurred in a particular tube material, the GBCD regions can be replenished with chromium if conditions for diffusion of chromium are allowed during the heat treatment. Therefore, sensitization (GBCD) cannot be ascertained by metallographic or electron microscopic examination. A Huey test (modified ASTM standard A-262) is currently being used to detect and quantify sensitization (GBCD). However, the limitations of this technique do not always permit reliable assessment of the GBCD.[14, 20]

The PWR steam generator tube-degradation mechanisms of fretting, erosion-corrosion, and high-cycle fatigue (North Anna type) are getting more attention lately because of recent failures. However, these degradation mechanisms are prevalent in only certain designs of steam generators and can be mitigated by design modifications.

8.3. Mitigation Techniques

Based on our current understanding of PWR steam generator tube-degradation mechanisms, certain measures will prevent or limit further tube degradation: (a) secondary-side chemical impurity control, (b) chemical additives that will inhibit corrosion, (c) periodic cleaning of the secondary side of the steam generator, (d) shot or rotopeening the inside surface of the tubes, (e) thermal treating, such as relieving stress in critical regions of the tubes, and (f) reducing the hot-leg-side temperature. The benefits of increased primary coolant pH to mitigate PWSCC via higher lithium or use of enriched boron are being evaluated.[26] Other measures, such as use of improved tube materials and modification of the tube supports, cannot be used in existing steam generators but can be incorporated into new designs. These measures are discussed in Section 8.5, Replacement of Steam Generators.

8.3.1 Secondary-Side Chemical Impurity Control. In-leakage of raw water through the condenser tubes is an important cause of the faulted chemistry conditions that result in denting, pitting, IGA, IGSCC, and excessive sludge formation. Several plants have replaced their admiralty brass condenser tubing with either titanium (seawater as well as freshwater sites), or stainless steel tubing (freshwater sites only) to prevent condenser leakage. Considering the somewhat poorer thermal conductivity, higher strength, and higher costs of titanium tubing compared to the previous brass tubing, a smaller wall thickness for the replacement titanium tubing is appropriate. But the lower titanium elastic stiffness may result in increased condenser-tube vibration problems. A number of titanium tube leaks in condensers have occurred. The possible degradation mechanisms for titanium tubing are high-cycle mechanical fatigue caused by flow-induced vibrations, damage from loose parts such as broken turbine blade pieces, and hydriding.[27] Additional design modifications may be needed to reduce the flow-induced vibrations. Use of titanium condenser tubing is a standard feature in the more recent plants.

Careful makeup water chemistry control is also needed to control the chloride content in the secondary water (in addition to controlling the in-leakage of raw water through the condenser). Organic impurities in the makeup water decompose at steam generator temperatures and produce additional chlorides (decomposition products). More chlorides may be introduced into the steam generator than indicated by an ordinary chemical analysis of the makeup water, unless the water sample is subjected to high temperatures and pressures before the analysis. One of the approaches to reducing the chloride and impurity input through the makeup water is to reduce the quantity of makeup water used. A blowdown recovery system will purify and recycle blowdown water that is cleaner in terms of chlorides and organic impurities than the usual supply of makeup water.

The various organic acid and ionic impurities mentioned in Section 8.2 can be minimized by ultrafiltration of the feedwater. The condensate in several plants is purified by flowing it through condensate polishers. Installation of ultrafiltration systems and full-flow condensate polishers, and the routing of the makeup water through the condensers and condensate polishers (rather than direct feeding to the steam generator) are some of the plant modifications that will improve the quality of the secondary water. Slippage of the ionic impurities can be controlled by adequate polisher flow capacity. However, accidental ingress of resins from these systems caused damaging chemical environments in some plants. In such events, immediate corrective actions are needed to remove the damaging chemicals from the secondary coolant. This may include shutting down of the reactor followed by numerous flushes to prevent damaging concentrations of soluble products in the crevices. Acidic conditions predominate when resins are released to a steam generator, because resins decompose at elevated temperatures.[6]

There are two opinions in the industry regarding the use of condensate polishers. One opinion is that they are unnecessary (if leak-tight condensers and ultrapure makeup water ensure water purity) and are also undesirable because large-scale damage can occur from resin ingress and slippage if polishers are not properly operated.[a,b] Therefore, several utilities do not use them. The other opinion is held by the several utilities who installed condensate polishers because of their benefits when they are properly operated (no resin ingress and slippage). Condensate polishers offer the only protection from large-scale damage to the steam generators caused by water chemistry transients (such as condenser leakage, fluoride contamination from repair welds, accidental ingress of chemicals, etc.). Some utilities are also installing filters between the polishers and the steam generators to trap any resins released from the polishers. This provides additional safety.

Copper is transported to the steam generators because of corrosion of components with copper-bearing alloys in the balance of the plant. The copper-bearing alloys (70/30 Cu Ni, 90/10 Cu Ni, brass, etc.) should generally be removed from the feedwater train to minimize the copper and copper oxide content in the secondary water. These components may be replaced with carbon or stainless steel (Types 347, 304, or 316) components. This replacement will reduce the rate of denting and pitting damage, because copper promotes these mechanisms. Controlling the dissolved oxygen and eliminating the ingress of air is also important in mitigating these mechanisms.

Constant monitoring of the water chemistry and immediate corrective actions are very important in maintaining the quality of the secondary water. Plant modifications that ensure the quality of the secondary water contribute to mitigating all the degradation mechanisms on the secondary side. They also minimize the formation of sludge. Reference 8 provides some generic guidelines for water chemistry controls.

8.3.2 Chemical Additives That Inhibit Corrosion. Because an AVT chemistry involves volatile compounds, constant on-line monitoring and addition of chemicals are needed to make up for the evaporation of the volatile species. Some plants are also either using or considering additional corrosion inhibitors such as boric acid and morpholine.

Laboratory studies indicate that the addition of boric acid will prevent denting and IGA and IGSCC initiation in environments that would otherwise cause damage.[15] Further findings indicate that adding boric acid after crack initiation in alkaline environments reduces the rate of crack propagation by a factor of 8 to 10. Boric acid can be added during normal plant operation and also during tubesheet crevice flushing operations performed during shutdown. A Japanese utility has reported that use of boric acid as a

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a. J. F. Hall and W. R. Gahwiller, private communication, Combustion Engineering, 1987.

b. A. P. L. Turner, private communication (V. N. Shah), Dominion Engineering Company, 1988.

neutralizing agent in two plants with full-flow condensate polishers retarded corrosion without degrading polisher performance.[15] Boric acid additions have also been effective in reducing the carbon steel corrosion and denting at ANO 2, Maine Yankee, and Fort Calhoun.

Morpholine has been used in several plants to inhibit corrosion. But only a dozen PWRs in the United States and a few in other countries continued its use after changing from a phosphate to an AVT chemistry. The data compiled from all the PWRs using morpholine indicate that its use as a supplement or substitute for ammonia prevents the grooving of brass condenser tubes, reduces balance-of-plant corrosion, and mitigates erosion-corrosion in steam lines and moisture separators.[28] However, the effects of morpholine additives on the transport of corrosion products and sludge buildup in the steam generators have not been fully determined. An increased amount of suspended solids in the blowdown stream has been observed at the plants using morpholine. Any chemical additive that reduces corrosion products and sludge transport in the feedwater could significantly reduce corrosion-related tube failures in the steam generators. Further studies on the impact of morpholine additives are in progress at Beaver Valley 1 and 2 and Prairie Island 1 and 2.

Additives that block the porosity in the magnetite layer may reduce the further oxidation of the metal underneath.[29] However, such additives have not yet been developed.

8.3.3 Steam Generator Secondary-Side Cleaning. The objectives of secondary-side cleaning are to remove (a) any residual phosphates remaining from the phosphate chemistry used prior to the switch to an AVT, (b) the sludge and the various chemical impurities and corrosion products located under the sludge, and (c) or neutralize the chemicals concentrated in the tube/tubesheet crevices and also in the tube/tube support annuli.

Lancing is a mechanical cleaning process using high-pressure water jets. The lancing methods offered by the various vendors differ, and their effectiveness also varies. Some lancing processes may leave considerable residue. The Steam Generator Owners' Group has developed a chemical process to remove the residue after lancing. When this process was tried in the first scale-up demonstration test in the laboratory, a layer of copper particles impeded the iron sludge dissolution.[30] The process was modified and successfully used at Millstone[31] and Maine Yankee.[a] The modified process uses ethylenediaminetetraacetic acid as a solvent and tends to produce a large volume of low-level radioactive waste, especially if there is a history of primary-to-secondary leakages at a given plant.

The other mechanical cleaning processes, pressure pulse and water slap, periodically release pressurized nitrogen at the bottom of the tube bundle.[32] The nitrogen produces upward movement of the water mass in the steam generator, thereby dislodging deposits from the tube surfaces and from the tubesheet and tube-support plate regions. The pressure pulse and water slap processes have been proven somewhat effective in removing corrosion products in recirculating and once-through steam generators, respectively. However, in contrast to chemical cleaning, the use of these processes has only resulted in short-term improvements.

A new mechanical cleaning process, a teleoperated robot, has been developed for removing steam generator sludge more safely and thoroughly than can now be done using conventional cleaning techniques. The teleoperated robot, called CECIL for Consolidated Edison Combined Inspection and Lancing system, is equipped with multidirectional, pressurized water jets with a pressure of 2500 psi. CECIL can remove sludge from all sides of the tubes, and a video camera allows the operator to inspect tube bundle conditions as the work progresses. The first field demonstration of CECIL provided encouraging results, and further refinements in its design are under way.[33,34]

The plant cooldown procedure at some plants is designed to achieve some cleaning of the secondary side. A typical practice is to hold (hot-soak) the steam generator at about 90 to 150°C (200 to 300°F) so as to place the trapped species back in solution. A combination of hot blowdowns and subsequent flushes with demineralized water are then used to reduce the inventory of soluble species. However, laboratory simulation studies with crevices filled with magnetite, sodium chloride, and/or sodium hydroxide solutions indicate that hot soaking alone will eject only about 8% of the impurities.[35]

The most common tubesheet crevice flushing technique is pressure cycling at about 150°C (300°F). Depressurization promotes boiling in the crevices,

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a. J. F. Hall and W. R. Gahwiller, private communication, Combustion Engineering, 1987.

which expels many of the impurities; repressurization then collapses the crevice voids and refills the crevices with water. A variation of this technique is to cycle the temperature to achieve boiling/refilling of the crevice fluids. Both the pressure and temperature cycling methods are equally effective. However, pressure cycling at about 90°C (200°F) has yielded about a 20 to 50% improvement over that at about 150°C (300°F) in laboratory tests.[35]

The creation of a large differential pressure between the crevice liquid and the bulk water is believed to be the most effective technique to boil the crevice fluids and expel the impurities. This can be achieved when the temperature of the tubesheet is maintained above the saturation temperature of the water. One method for achieving a higher tubesheet temperature is to shut the reactor coolant pump off during the hot-soak period so that the circulating primary system coolant does not cool the tubesheet.[36] With only natural circulation on the primary side, the secondary-side crevice-water temperature can be maintained above the secondary-side bulk water temperature that creates a greater pressure differential between the crevice and the bulk fluids on the secondary side.

8.3.4 Shot Peening and Rotopeening the Tubing. The highly stressed inside surfaces of Alloy 600 steam generator tube/tubesheet-rolled joint can be shot peened (or rotopeened) to reduce the susceptibility of the material to PWSCC. The peening is done in most tubes only in the transition region between the deformed and nondeformed portions of the tubing using the primary side access to the tubing; some tubes are peened over the full length of the tubesheet.

Both the shot and rotopeening processes use the impact of a high-velocity small-diameter mass on the inside surface to produce a layer of cold worked material a few tens of microns deep. This process introduces compressive residual stresses that tend to preclude PWSCC. Shot peening uses high-velocity metallic, ceramic, or glass particles. Rotopeening uses the impact of shots bonded to fabric in a flapper wheel and requires remote tooling in a radioactive plant. The rotopeening process was developed because of concerns about the spread of contamination and the abrasive particles associated with shot peening.[37] However, the shot peening process is now preferred because the concerns for the spread of contamination have been adequately addressed. The effectiveness of the peening depends entirely on the process controls, because there is no postprocess nondestructive field inspection technique that can quantify the benefit. This is a preventive technique, not a repair method for an already cracked tube.

8.3.5 Stress Relieving or Annealing the U-Bends. Stress relieving or annealing will also reduce the susceptibility of Alloy 600 to PWSCC, particularly at the U-bends. However, this is a difficult process to perform under field conditions. Also, stress relieving of Alloy 600 tubes in the 650 to 760°C (1200 to 1400°F) range may cause sensitization (formation of chromium depleted regions near grain boundaries) and susceptibility to secondary-side IGA/IGSCC. However, this may not be a concern for Alloy 600 material with intragranular carbides and low solid-solution carbon content. Thermally treated Inconel 600 and 690 may also be stress-relieved without causing sensitization. Other potential problems associated with stress-relieving the tubesheet region of a steam generator include possible microstructural and property changes in the tubesheet material, and possible opening of the crevices. Processes have been developed to preclude these problems.[38]

In situ stress relieving of the critical tube bends has been performed at Sequoyah 1. U-bend annealing has also been performed at a limited number of new plants.[39] Field performance data are not yet available, and these processes may not be useful for tubing that has already cracked. Laboratory studies indicate that the use of in situ stress relief techniques would result in at least a factor of 10 increase in the time of PWSCC initiation.[40] Guidelines for in situ stress relieving are provided in Reference 38.

8.3.6 Reducing the Hot-Leg-Side Temperature. Reducing the temperature of the tubing on the hot-leg side by about 10°C (20°F) or more is believed to slow down, though not preclude, various damage mechanisms on the secondary side.[41] This is a temporary mitigation technique that can increase the time between the steam generator outages required for inspection. Plant availability is increased, but this benefit is offset by reduced power during operation.[41]

8.4. Repair

When a PWR steam generator tube defect is detected, the following options are available: (a) decide that the flaw is acceptable (small enough) and continue to use the degraded tube, (b) plug the tube, and (c) sleeve the defected region of the tube.

8.4.1 Flaw-Acceptance Criteria for Tube Integrity. Various nondestructive examination (NDE) techniques can locate and size relatively large PWR steam generator tube flaws (axial and circumferential dimensions and depth of flaws). However, the utilities cannot conclusively identify the various failure mechanisms using NDE. A cluster of closely spaced pits and IGA/IGSCC defects may give similar signals. Removal of a representative tube with a defect and a subsequent destructive examination are often needed to identify the mechanism.

Guidance for acceptable flaw sizes is given in USNRC Regulatory Guide 1.121. PWR steam generator tubes with NDE flaw indications less than 40% of the wall thickness can continue to operate. Fifty percent through-wall depth indications are permitted in some plants with tubing with larger wall thicknesses (for example, Conneticut Yankee). A tube with a fully circumferential flaw of a permissible depth should be a factor of three or more from burst, assuming full primary-side pressure and no secondary-side pressure. The same factor of three or more applies to collapse, assuming no primary-side pressure and full secondary-side pressure. Since the flaw acceptance criterion is the same for all damage mechanisms, namely wastage, pitting, IGA, IGSCC, and PWSCC, the fact that the utility cannot identify the exact mechanism using NDE is not a regulatory problem. However, the mechanism should be identified to (a) determine whether the flaw will grow rapidly during continued plant operation and (b) develop mitigation strategies.

The flaw acceptance criterion is designed to accommodate possible errors in NDE flaw sizing, and also possible growth of the flaw during continued operation. The growth of the defect can be monitored by reinspection of those tubes with significant indications that were permitted to continue operation after the previous inspection. A fully circumferential flaw, a flaw that covers only part of the tube circumference, and a pit are conservatively governed by the same maximum permissible depth, that is, the one for the fully circumferential flaw.

The ASME Code Section XI does not specifically provide flaw-acceptance criteria for steam generator tubing. However, the factor of three on the pressure load specified in Regulatory Guide 1.121 is generally consistent with ASME Code philosophy. A flaw-acceptance criterion for austenitic piping (Article IWB-3640) has recently been added to the Code and is primarily being used for BWR piping. Although it is intended for all austenitic materials, including Alloys 600 and 690, the industry has not evaluated its use for PWR steam-generator tubing. Tube-pit depths of as much as 75% of the wall thickness (end-of-life projected dimension considering possible growth during the remaining life) may be permissible under this article of the Code.

Apart from the pressure loads discussed above, the tubes may also experience significant bending loads during some unanticipated events such as a loss-of-coolant accident. The bending loads arise when the pressure of the primary coolant drops at one end of the tubes during a transient. However, a recent study demonstrated that tubes with flaws of 40 to 50% of the wall depth do not fail during such events.[42]

8.4.2 Plugging. Plugging was the only countermeasure available for PWR steam generator tubes with unacceptable flaws, until a few years ago. Denting has caused several hundreds of tubes to be plugged in some plants. Even now, plugging is commonly done for unacceptable degradation above the tubesheet region, because most of the current sleeving techniques extend only a few inches above the tubesheet and the sludge-pile region. Commonly used techniques to plug a tube include welding, explosive forming, and mechanical installation. Plugs installed with explosive forming have leaked in at least three plants because of large plastic strains and unfavorable residual stresses at plug corners. Mechanical plugs are installed without welding or explosive forming and may be removed later.[37]

A plugged tube may continue to be susceptible to corrosion, fatigue, and fretting damage, and finally sever. However, the temperature of a plugged tube is about 40°C (70°F) less than an unplugged tube on the hot-leg side. This will greatly reduce the corrosion rates. A severed tube may experience large amplitude vibrations because of fluid-elastic instability and then damage neighboring tubes. To prevent this, plugged tubes may be stiffened by inserting stabilizers, for example, solid rod segments that can be threaded to each other and to the plug.[43]

Alloy 600 plug materials not heated to sufficiently high temperatures during the mill annealing process are susceptible to PWSCC.[44] PWSCC may cause leakage of primary coolant through such a faulty plug or cause its failure. A plugged tube within the retired Surry 2 steam generator was found to be filled with pressurized primary coolant, an indication of a leaking plug. Also, PWSCC may cause a plug to fail, rather than just leak, and release fragments of the plug into the tube. Such a failure of a tube plug recently took place in Virginia Power's North Anna 1 unit. The 2.5-in.-long, 0.75-in.-diameter Inconel 600 plug was subjected to low mill-annealing temperatures during manufacturing. The severed-off portion of the plug shot up the tube, punctured the tube near its apex, and damaged one adjacent tube.[45] Alloy 600 plugs susceptible to IGSCC have been installed in about 7000 tubes in approximately 20 United States PWR plants.

Despite the plugging of a relatively large number of tubes, a steam generator may still generate the rated capacity of electricity because it normally starts operation with a significant margin of available capacity. However, continued plugging after the margin is exhausted can significantly reduce plant capacity, as shown in Figure 8.2.[41] Also, the plugging of a very large number of tubes can impact the thermohydraulics of a steam generator and result in safety problems. Before this occurs, the potential economic consequences (cost of anticipated repairs and cost of lost capacity from plugged tubes) should necessitate extensive sleeving or steam generator replacement. Steam generators lose their capacity margin when about 20% of the tubes are plugged.

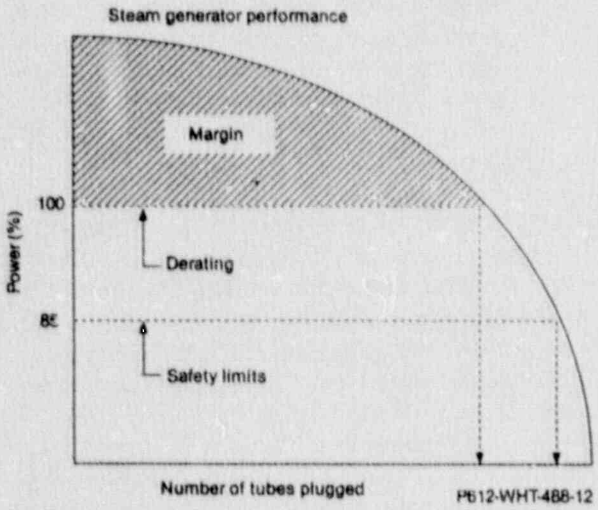

Figure 8.2. Plant power capacity drops rapidly with increasing number of plugged tubes.[41]

8.4.3 Sleeving. Most of the currently available sleeving techniques are designed to cover the inside surfaces of PWR steam generator tubes in the region from the bottom of the tubesheet to slightly above the sludge piles. This is adequate for most tube defects in recirculating type steam generators because the majority of the tube defects on both the primary and secondary sides occur within the tubesheet and sludge pile. The available head room is smaller for the tubes in the outer rows. Therefore, shorter sleeves must be installed in such tubes to address the access problem illustrated in Figure 8.3. The fatigue and erosion-corrosion degradation mechanisms in once-through steam generators are operative mostly near the top tubesheet, so sleeving is done from the upper tubesheet down to the first tube-support plate.

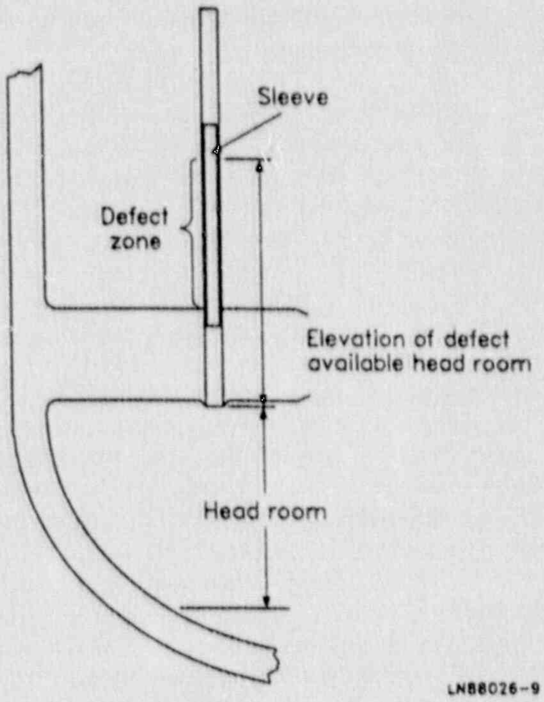

Figure 8.3. A sleeve that meets the head-room limitation is positioned to span the defect zone.[46]

A sleeving operation involves a combination of two or more of the following processes: (a) rolling, (b) hydraulic expansion, (c) tungsten inert gas welding, (d) explosive welding, and (e) brazing. Some typical sleeving methods are discussed in the following paragraphs.

Despite the plugging of a relatively large number of tubes, a steam generator may still generate the rated capacity of electricity because it normally starts operation with a significant margin of available capacity. However, continued plugging after the margin is exhausted can significantly reduce plant capacity, as shown in Figure 8.2.[41] Also, the plugging of a very large number of tubes can impact the thermohydraulics of a steam generator and result in safety problems. Before this occurs, the potential economic consequences (cost of anticipated repairs and cost of lost capacity from plugged tubes) should necessitate extensive sleeving or steam generator replacement. Steam generators lose their capacity margin when about 20% of the tubes are plugged.

The sleeving initially installed at Ginna by B&W (Figure 8.4) used tubes that covered the region from the bottom of the tubesheet to about 150 to 300 mm (6 to 12 in.) above the tubesheet top surface. It involved hydraulic expansion at both the top and bottom joints, brazing at the top joint, and explosive welding at the bottom joint. The sleeve material was thermally treated Alloy 690 with nickel bonded on the outside surface for increased resistance to IGA. The hydraulic expansion and explosive welding processes are likely to produce less residual stresses than the hard rolling process used during B&W's process development studies.[46] However, this design resulted in leaks, and an all-welded sleeve design (described later) is now being used in sleeving at this plant.[a]

a. J. F. Hall and W. R. Gahwiller, private communication, Combustion Engineering, 1987.

The leak-tight expansion shown in Figure 8.5 can be used for tubes having PWSCC defects in the roll transition region between the deformed and undeformed portions of the tube without any additional sleeving material. Even if the crack in the defect region propagates farther, it is no longer a concern because the leak-tight expansion provides a new tube/tubesheet joint well above the old joint.

Another approach to the repair of roll transition region PWSCC defects is the design used on an experimental basis at the Doel plant (illustrated in Figure 8.6). This approach uses a thin Alloy 690 minisleeve about 40-mm (1.5-in.) long, explosively welded over the cracked tube. A portion of the tube that was not previously expanded is now expanded against the tubesheet, thereby providing the load carrying capability. In other words, the transition region between the deformed and nondeformed portions of the tube is now in a new defect-free location, with probably less residual stresses than the original hard-rolled joint. The sleeve is so thin that the inside

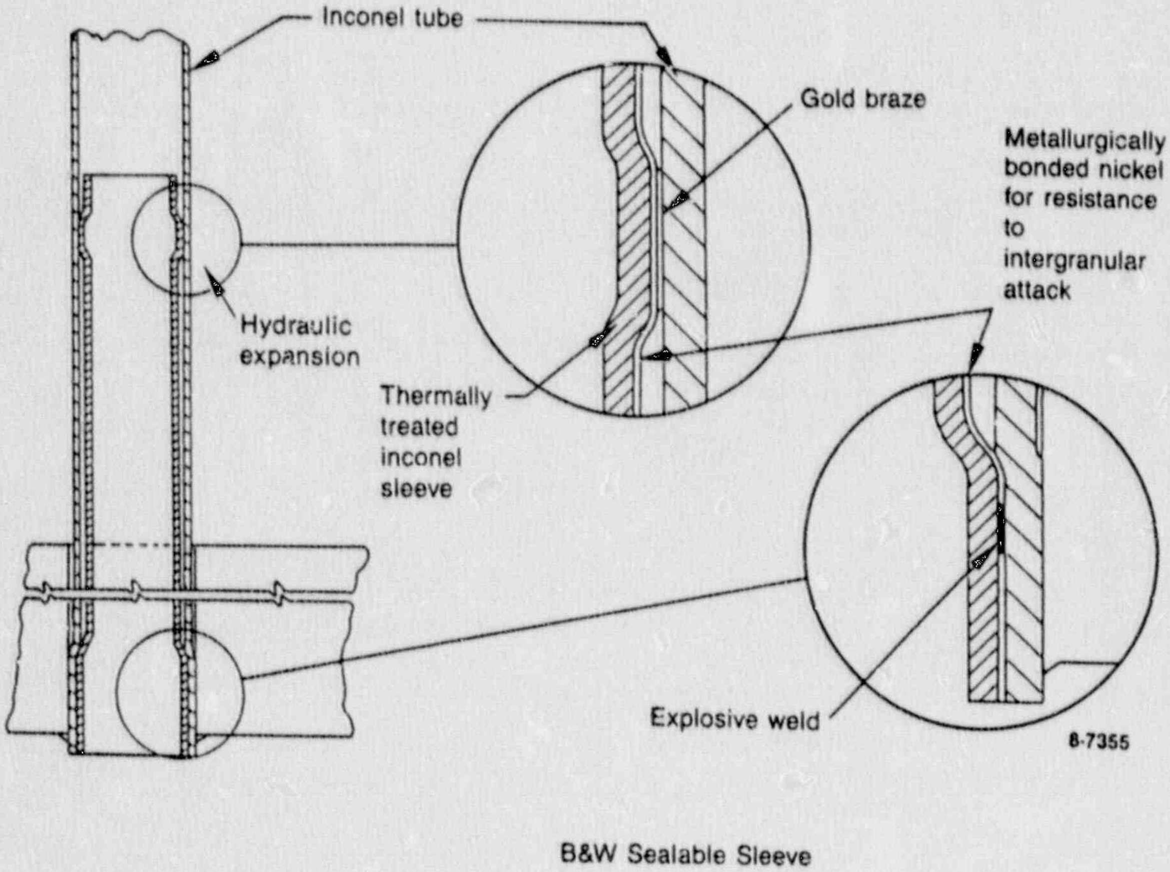

Figure 8.4. Sealable sleeve design from Babcock & Wilcox.[46]

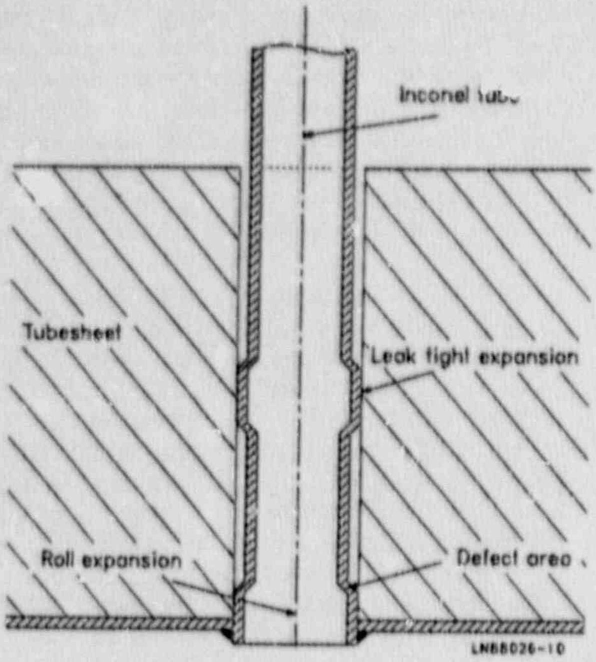

Figure 8.5. Leak–tight expansion–joint design (Babcock & Wilcox) for PWSCC at tubesheet roll joint.[46]

dimension of the tube is practically not altered, allowing full flow of reactor coolant. This design does not preclude the future use of a longer sleeve with other designs and processes if new defects are found later. It is one of the quickest sleeving techniques and minimizes personnel radiation exposure.[46] However, the PWSCC mechanism is still operative at the next transition region and new cracks have developed there.[a]

The welded–sleeve process, shown in Figure 8.7, uses a hydraulic expansion followed by tungsten–inert–gas (TIG) welds between an Alloy 690 sleeve and the parent tube. The sleeve length is chosen to ensure the top joint is above the tubesheet and sludge pile areas. This will cover most of the defects on the primary as well as the secondary sides of the tubing. Each sleeve is hydraulicly expanded and then welded at the top to the parent tube, and then welded at the bottom of the tubesheet, irrespective of the specific location of the defect in between. The weld regions must be prepared before sleeving to remove any oxidation or corrosion layers, thereby ensuring a proper metallurgical bond. The weld parameters must

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a. A. P. L. Turner, private communication (V. N. Shah), Dominion Engineering Company, 1988.

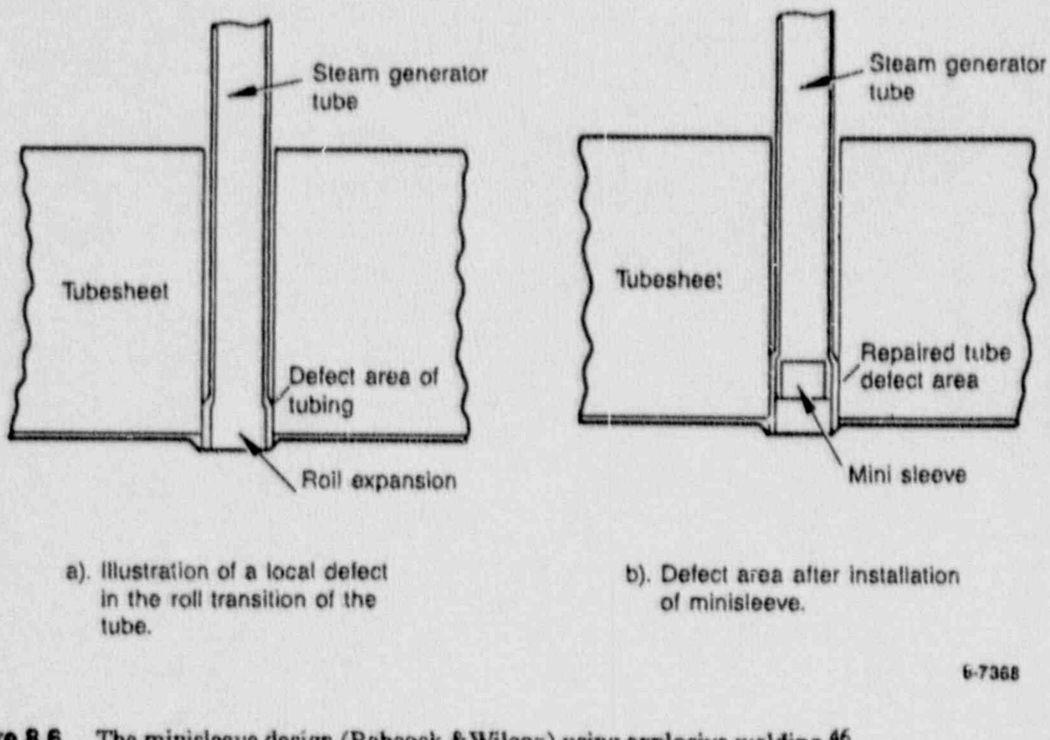

Figure 8.6. The minisleeve design (Babcock & Wilcox) using explosive welding.[46]

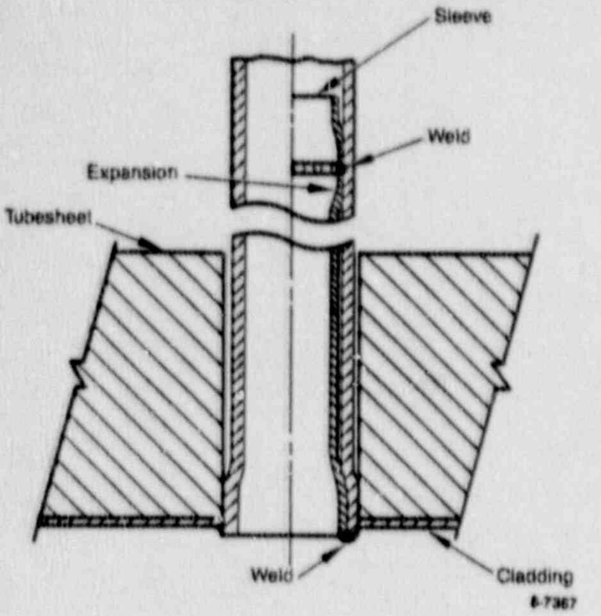

Figure 8.7. Welded sleeve design (Combustion Engineering).

be optimized on a plant-specific basis because the tubing in different plants has somewhat different dimensions (wall thickness and diameter). In fact, the tubes in a given plant may have a range of wall thickness, with $\pm 10\%$ the typical tolerance permitted for PWR steam generator tubing. This tolerance can amount to about a 20% variation in wall thicknesses in a given plant. The variation may be more if wastage (metal loss from corrosion) has occurred. Wastage can also promote nonuniform wall thickness around the circumference of a tube. Also, the concentricity between the inside and outside surfaces was not strictly controlled in most original tube specifications. Success in producing a good metallurgical bond in the weld will, therefore, depend on optimizing the weld parameters on mockup tubing typical of that in the plant. The hydraulic expansion makes a portion of the sleeve conform to the parent tube and controls the clearance between the sleeve and the parent tube prior to the welding. If a weld is found to be leaky or it does not pass the NDE, another repair weld can be made in close proximity. The welded-sleeve approach has been successfully demonstrated at Ringhals 2 and other plants.[46, a]

A hybrid expansion joint employs a combination of hydraulic expansion and rolling and has been used in several plants. An approximately 100-mm- (4-in.-) long hydraulically expanded area is first formed. After the expansion, there is some elastic spring back of the deformed regions of the sleeve. Then a 50-mm- (2-in.-) long hard roll is made in the hydraulically expanded region, making a leak-tight mechanical joint. The sleeve material is either thermally treated Alloy 600, or a bimetallic material with Alloy 625 over Alloy 690. The Alloy 625 provides better pitting resistance. One variation of the method is the use of brazing instead of hard rolling. The success of the braze depends upon several empirical parameters that vary with field conditions. Despite the fact that some of the brazed joints passed the hydrostatic tests, ultrasonic testing indicated some of them had a poor bond. Currently, the hard-rolled sleeve with a hybrid expansion joint is preferred to the brazed joint. However, in a hard rolled joint, the joint's residual stresses in the sleeve and the parent tube are of concern and the joint may be susceptible to both primary and secondary-side IGSCC. The residual stresses in a hard rolled joint can be minimized by various process controls but cannot be quantified by the NDE. Techniques are also available for reaming small dents at the tubesheet prior to the sleeve installation.[46]

Generally, about 25 mm (1 in.) or more of the sleeve extends over the top joint. If a circumferential crack propagates through the original tube wall at the joint location, resulting in a double-ended break (a definite safety concern), the portion of the sleeve that extends over the joint is expected to keep the failed parent tube in place and prevent any whipping against other tubes. This would not be helpful if the crack extends through the sleeve as well the tube. Some European designs do not have this feature. For example, a fillet weld is used at the end of the sleeve in one design. In another design, the defective portion of the parent tube is cut and pulled out, and a sleeve is butt-welded to the parent tube. Propagation of the defect is prevented because the defect and the susceptible material are removed from the critical region. The benefit of the extended-sleeve designs described above has not been experimentally demonstrated. There is a concern that the thrust from escaping coolant will force the tube off the end of the sleeve despite the restraint from the extended portion of the sleeve.[a] The extended portion would not be helpful if the crack extends through the sleeves as well as the tube. However, the sleeve material is unlikely to fail before the degraded parent tube because it is new. Despite some limitations, the use of an extended portion in the tube probably

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a. J. F. Hall and W. R. Gahwiller, private communication, Combustion Engineering, 1987.

provides a safety benefit with no known adverse consequences.

It is very likely that new methods will become available in addition to the methods discussed above. The following are some of the criteria for comparing various alternatives: (a) reliable leak-tight joints as evidenced by the NDE hydrostatic pressure testing and performance immediately after the plant startup, (b) long-term reliability, (c) the ease of rerepair in case a sleeved tube leaks, (d) inspectability of the joint, (e) inspectability of the parent tube after the joint is made, (f) cost of sleeving a large number of tubes (including outage costs) as compared with the cost of steam generator replacement, and (g) the amount of radiation exposure to personnel performing the repair. There are no published studies that compare and contrast the various sleeving designs. A design review checklist has been developed for evaluating a given design.[47]

All the sleeving designs are relatively new and there are little long-term field performance data on any of these designs. An important concern is that most sleeves create high residual stresses in the parent tubing and sleeve, which may cause new cracks. The effects of residual stresses can be evaluated in the laboratory using mockup sleeve joints but cannot be easily measured in the field. For example, the effects of the geometric stress raisers introduced by the sleeves on the corrosion-fatigue resistance of the parent tubing are unknown. Also, the sleeves introduce crevices on the primary side, and the long-term impact of these crevices is not known. And finally, it will be difficult to inspect the sleeves for flaws. When a defect on the parent tube grows through the wall, the gap between the parent tube and the sleeve will be filled with stagnant secondary water that may promote IGSCC or IGA or both. All the issues discussed here need further study and a databank should be developed to help researchers understand and predict the performance of plugged and sleeved PWR steam generator tubing.

8.4.4 Nickel Plating. A nickel plating technique has been developed by Framatome and Belgatom to repair IGSCC cracks in PWR steam generator tubes.[48,49] The concept is illustrated in Figure 8.8. The nickel plating consists of electrolytically cleaning the damaged surface and then depositing up to about 200 microns (8 mils) of pure nickel on the damaged surface. The

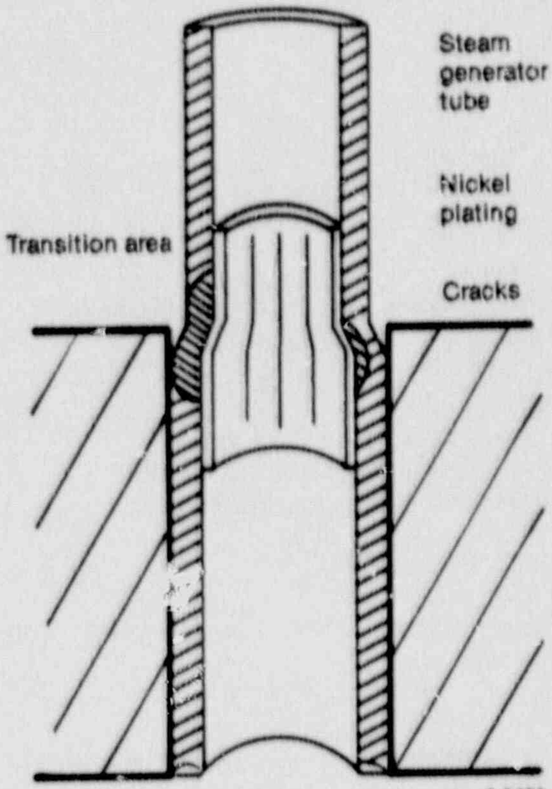

Figure 8.8. Nickel plating of roll transition region having PWSCC cracks.

nickel deposit on the damaged tube wall bridges the through-wall cracks and stops leakage of primary coolant into the secondary system. In addition, the nickel deposit prevents contact between the primary coolant and the damaged tube wall, arresting crack propagation and stopping the initiation of new cracks. Nickel plating has several advantages over sleeving. It generates very low residual stresses and does not require a subsequent heat treatment, and it can be applied anywhere in the straight part of the tube. It also allows later access to areas above the plated section for repair of further damage, whereas sleeving does not. Nickel plating is a reversible process because, if needed, the plating can be stripped off chemically without damaging the tube.

The nickel plating process has one major drawback with respect to inservice inspection of the plated region. Because nickel is magnetic, the nickel layer creates a barrier to the small magnetic field introduced by conventional eddy current coils, and these methods cannot be used to inspect a nickel-plated region. However, new ultrasonic inspection method capable of detecting axial and circumferential cracks has been developed to overcome this problem. Pulsed magnetic

a. A. P. L. Turner, private communication (V. N. Shah), Dominion Engineering Company, 1988.

saturation eddy current techniques may be used for inspecting nickel-plated tubes.[50]

Nickel plating was first applied to 91 tubes in 1985 as a field trial to evaluate different plating methods. Based on the experience gained by the field trials and laboratory test results, an optimum plating process was developed and applied in 1988 to the most severely cracked roll transition regions of steam generator tubes in Doel 2 and Doel 3 (Belgium).

8.5 Replacement of Steam Generators

The loss of power attributed to plugging of the steam generator tubes or the effort involved in sleeving a large number of tubes may not be acceptable. In such a situation, the following alternatives are available: (a) retubing the steam generator using the existing tubesheet and shell structures, (b) replacing the entire steam generator, and (c) replacing the lower assembly of the steam generator.

In-place steam-generator retubing involves cutting and removing the tubes and tube-support structures and replacing the steam drying and separation equipment. The technical feasibility of this process has been demonstrated by the Westinghouse Electric Company in a mockup facility, but retubing has not been used at any utility because it requires a two- to three-year outage period. The cost of the lost power during the outage is significantly higher than the cost of the other repair/replacement options. The site work involves as much fabrication as in manufacturing a new steam generator, and the process controls may not be as effective in the field as in the shop. This option also involves a significantly large radiation exposure to the personnel.

Twenty-five steam generators have been replaced at eight U.S. PWRs (as of July 1989) making replacement less of an unknown in terms of cost, schedule, and exposure.[23] Steam generator replacement is considered likely at eight additional United States plants and has occurred at, at least, two foreign plants. Successful steam-generator replacement has been accomplished at Surry Units 1 and 2 (Virginia Power), Turkey Point Units 3 and 4 (Florida Power and Light), Point Beach Unit 1 (Wisconsin Electric Power), Obrighein (West Germany), Robinson Unit 2 (Carolina Power & Light), D. C. Cook 2 (Indiana & Michigan Electric Co.), Indian Point 3 (New York Power Authority), and Ringhals 2 (Swedish State Power Board).

The replacement of the steam generators at the Surry plants involved cutting the piping (primary and secondary), forcing the generators from their supports, and removing them through existing equipment hatches in the containments, as shown in Figure 8.9.[51] The site preparation included upgrading the polar cranes; installing new cranes and other handling equipment; and constructing an on-site storage facility, stronger hatch platforms, and shielding. Considerable decontamination work was also required.

Replacement of the lower assembly of a steam generator involves cutting the steam generator at the transition cone and removing the lower assembly, including the tubesheet forging, tubes, etc., and then replacing it with a new lower assembly. This approach was chosen at Turkey Point, because the entire steam generators would not fit through the existing equipment hatches. The initial plans to cut the reactor coolant piping at Turkey Point were abandoned because of access problems. A channel head cut was used instead. The procedure to weld the channel head was revised to reduce welding from inside the head. Cladding the inside of the channel head was more difficult than anticipated.

Because utilities are now exchanging steam generator replacement experience, the outage times caused by replacement have been reduced to about six months or less. The recent replacement of the three steam generators at Ringhals 2 were completed in 72 days.[23] The video tapes of the fieldwork performed at one plant have been helpful in the planning and training (as well as in identifying potential problems) at other plants. The critical component for timely manufacture of a new steam generator is the tubesheet forging. Some utilities are investing in storing such critical-path components in a pooled inventory management system (PIMS), so that any utility may purchase such a component from PIMS when needed.[a]

Steam generator replacement is expected to result in a longer steam generator life than repair because design and materials improvements can be implemented and the impact of prior operating history is removed. Some of the improvements that can be incorporated into new steam generators are discussed next.

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a. M. F. Ahern, private communication, Northeast Utilities Service Company, 1987.

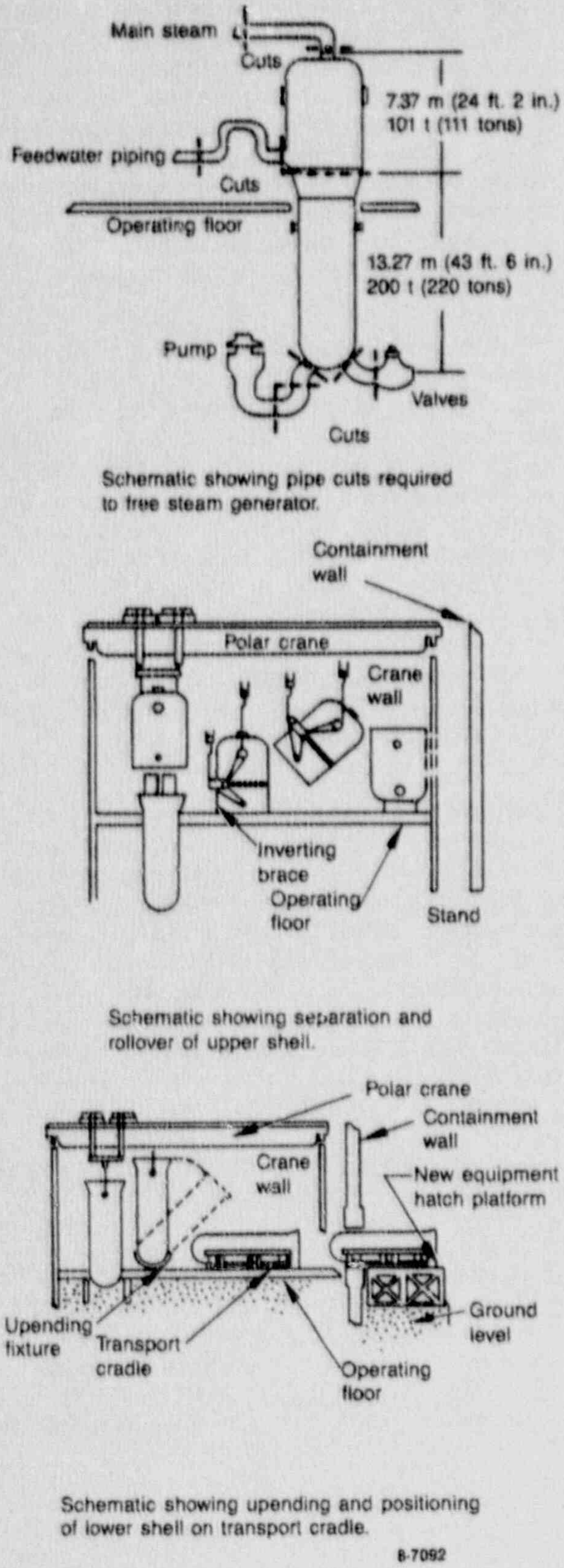

Figure 8.9. Steam generator replacement operations at Surry plant.[51]

The United States industry's consensus on the best steam generator tube material is thermally treated Alloy 690. The thermal treatment, as well as the relatively high chromium content of this material, precludes the development of chromium-depleted regions near the grain boundaries that cause sensitization and, therefore, the susceptibility to IGA/IGSCC. Alloy 690 is also expected to have a higher resistance to PWSCC than mill-annealed Alloy 600 material because Alloy 690 has grain boundary carbides and a yield strength below 380 MPa (55 ksi). A mechanistic correlation between microstructure and PWSCC is presently not established; the postulated optimum microstructure is based on empirical field observations and laboratory tests.[20] Modified Alloy 800 (carbide forming elements added to limit the solid solution carbon content) is resistant to PWSCC, and it has been successfully used in West Germany. The success of modified Alloy 800 may also be attributed to strict water chemistry controls in the German plants, leak-tight condensers with titanium tubing, and the fresh-water plant locations. Thermally treated Alloy 690 has better resistance to acid chloride ingress (pitting, IGA, and IGSCC) than Alloy 800, based on laboratory studies. Also, mill-annealed Alloy 800 is prone to pitting in a fresh-water environment (such as water from Lake Ontario).[52] The typical chemical composition of an Alloy 800 material includes 0.06% C, 32% Ni, 20% Cr, 46% Fe and small percentages of Mn, Al, Si, and Mg. The typical yield strength of mill-annealed Alloy 800 is about 185 MPa (27 ksi) which is much lower than that of Alloys 600 and 690, and the average grain size is 31.3 μm, which is much larger than that of Alloy 600.[22] The new tube/tubesheet joints in the replacement steam generators have eliminated crevices where impurities can concentrate.

The residual stresses at the tubesheet joint and at the U-bends in the new steam generators have been reduced using peening and stress relieving/annealing techniques, respectively. The new manufacturing processes have been designed to minimize residual stresses. Access for sleeving and other repairs has also been improved.

The tube supports have also been improved to preclude denting. The tube-support structures in new steam generators are now being fabricated with 12% chromium ferritic stainless steels such as Types 409 or 405, both relatively resistant to oxidation. Design modifications of the tube support structures (such as the quatrafoil or trifoil designs) prevent fluid stagnation in the tube/tubesheet annuli. However, water chemistry control is still very important. The material and design of the tube supports should also minimize fretting and wear damage on the tubes.

Improved access for secondary-side lancing and chemical cleaning of the tubesheet top surface has been incorporated with hand holes in appropriate locations. Increased blowdown capacity will help in removing the impurities and in reducing the accumulation of sludge.

Ease of future repairs and replacements is now being considered in the design of the replacement steam generators. Unlike some European designs, the original United States designs of the PWR steam generators and the containments did not anticipate the need for steam generator replacement during the plant life.

8.6 Summary, Conclusions, and Recommendations

The important degradation sites, stressors, degradation mechanisms, potential failure modes, and current ISI requirements associated with PWR steam-generator tubes are presented in Reference 1, and summarized in Table 8.2. Some of the degradation mechanisms, that is, IGSCC, IGA, pitting, wastage, and denting have caused more tube failures in the recirculating type steam generator than in the once-through steam generators. Fretting, erosion-corrosion, and fatigue damage is receiving more attention because of recent failures; however, these problems are limited to particular steam generator designs. Table 8.3 summarizes the techniques for mitigating the damage resulting from the important aging degradation mechanisms. Table 8.3 also summarizes the improvements made in new/replacement steam generators and other secondary side components to reduce PWR steam generator tube degradation. Long-term field-experience data are needed to assess the effectiveness of the various countermeasures. Inservice inspection methods and quantitative models are needed to estimate the magnitude and rate of the damage. The conclusions and recommendations regarding the countermeasures for steam generator tube failures are as follows:

1. The highest priority is given to preventing faulted conditions in the secondary water chemistry. Some water chemistry transients can cause large-scale damage in a short time. Remedies include preventing condenser leakages, improving makeup water purity, frequent water chemistry checks, and preventing resin or chemical releases from condensate polishers. Installing titanium tubing in the condensers reduces the possibility of leaks. However, titanium tubing is susceptible to fatigue caused by vibrations. Impurities in the secondary water can be minimized by ultrafiltration of the makeup water, feeding makeup water through condensate polishers, and reducing the quantity of makeup water by recycling blowdown water using a recovery system. The Steam Generator Owners' Group guidelines for continuous monitoring and control of water chemistry should be followed to reduce impurities in the secondary water. Because copper enhances denting and pitting processes, it is desirable to eliminate copper and copper containing alloys from the secondary side.

2. In several plants, condensate polishers are considered unnecessary and unsafe because they can cause damage to the tubing if resins or chemicals are accidentally released from misoperation of or mechanical damage to the condensate polishers. The operators of some plants believe that condensate polishers provide the only defense against faulted water chemistry conditions. Condensate polishers routinely remove impurities and mitigate degradation processes in steam generators. Additional safety can be provided by installing filters between the polishers and steam generators to collect any accidentally released resins.

3. Plant studies have demonstrated that certain chemical additives, that is, boric acid and morpholine, will mitigate intergranular attack, intergranular stress-corrosion cracking, denting of the steam generator tubes, and general corrosion of the carbon steel components in the feed-water system. These chemical additives do not adversely influence other plant components.

4. Several utilities have successfully used secondary-side cleaning methods, such as lancing with a high-pressure water jet and subsequent chemical cleaning, that remove residues. Removal of copper-bearing sludge from the secondary side allows the detection of some defects, such as pitting, during inservice inspection. Several methods have also been developed to clean tubesheet crevices with hot soaks and tubesheet crevice flushing techniques.

Table 8.3. Summary of countermeasures for tube failures in PWR steam generators

Mechanism	Mitigation of Damage in Existing Tubes[a]	Improvements in New/Replacement Steam Generators
Primary side SCC	Roto/Shot Peen to improve residual stresses; anneal the U-bends and control the denting problem.	Use Alloy 690 tubes with optimum microstructure and a maximum yield strength of about 380 MPa (55 ksi); and minimize/eliminate residual stresses
Secondary Side Defects:		
Intergranular stress corrosion cracking, inter-granular attack	Control alkaline impurities, eliminate acid chlorides, flush tubesheet crevices, use hot soak, lance, and chemically clean; neutralize crevice alkalinity; add boric acid; and roll tubes to eliminate crevices.	Use Alloy 690 tubes with optimum microstructure,eliminate tubesheet crevices, improve access for lancing and cleaning, increase blowdown capacity, shot peen OD, and design flow to avoid sludge accumulation.
Pitting	Eliminate condenser leakages; preclude ingress of air/oxygen, acid chloride, and copper in water.	Use titanium or stainless steel condenser tubes, eliminate Cu alloys in feed train, and resistant tube materials.
Denting	Eliminate ingress of air/oxygen, acid chlorides, and copper in water; use leak-tight condensers, use hot soaks.	Use strict water chemistry controls, use stainless steel support structures, and design to preclude stagnant water in annuli, and titanium condenser tubes.
Wastage	Use AVT water chemistry; eliminate hideout chemical concentrations; use sludge lancing and chemically clean; use hot soaks; hot blowdown and flushing; preclude resin ingress.	Design flow to preclude hideout and chemical concentrations; minimize sludge formation; improve access for cleaning, and increase blowdown capacity.
Fatigue in OTSG (thermal and environmental)	Control chemistry and modify to preclude dryout of water particles with impurities on tubes near the open lane.	—

a. Repair generally consists of plugging or sleeving or various new expansion joints in the tubesheet region. Various size sleeves and minisleeves have been used.

5. Shot and rotopeening techniques have been used to introduce residual compressive stresses on the tube inside surface to mitigate pure water stress corrosion cracking (PWSCC). However, no NDE method is available to measure the residual stresses. Effectiveness of these techniques depends upon process controls.

6. Alloy 600 and 690 microstructures and heat treatments have been developed that result in an increased resistance to PWSCC in laboratory tests. However, further research is needed to gain a fundamental understanding of the mechanisms of PWSCC.

7. Grain boundary carbides provide increased resistance to PWSCC; however, sensitization (grain boundary chromium depletion) should be avoided to ensure resistance to secondary-side faulted chemistry conditions. Thermal treatments can produce resistance to both

primary and secondary-side degradation processes.

8. In situ stress relieving of highly stressed regions, such as U-bends, has been used in some plants to prevent PWSCC in tubing that has not cracked. Sufficient care should be taken to avoid formation of chromium-depleted zones near grain boundaries. The use of increased pH in the primary coolant to mitigate PWSCC is being evaluated. The increased pH may be achieved via higher lithium or through use of enriched boron.

9. The material specifications for PWR steam generator tubing (Alloy 600 or 690) should require a maximum yield strength of about 380 MPa (55 ksi), which will limit the maximum residual stresses. Presently, there is no maximum yield strength requirement in the current ASME Code specifications for these materials.

10. The current allowable NDE flaw-indication criterion specified by the NRC is conservative when the accepted flaw does not grow rapidly during plant operation. Efforts to reduce the uncertainties in the NDE results, quantify flaw growth rates, and determine safety margins during operations should be continued.

11. Several effective sleeving designs have been developed recently to cover defects in the tubes near the tubesheet region. Leak tightness of sleeved tubes is monitored in subsequent plant operation. Use of sleeves introduces residual stresses that cannot be measured, presents difficulties for future inspections, forms crevices on the primary side, introduces geometric stress raisers, and poses concerns in the event of a double-ended tube break at the sleeve joints. Therefore, the field performance of the various sleeve designs should be monitored.

12. Plugging is the only remedy when unacceptable flaws are detected in regions away from the tubesheet. However, some plugs are susceptible to PWSCC (plugs with low mill-annealing temperatures). If PWSCC causes a plug failure instead of leakage, the fragments of the failed plug may enter the tube with sufficient velocity to puncture the tube and possibly damage neighboring tubes. Plugs can be removed for future repair if needed. Plugging too many tubes is likely to affect the steam generator thermalhydraulics. Inservice inspection methods to assess the integrity of plugs need to be developed.

13. A nickel plating technique is being developed to repair IGSCC cracks in steam-generator tubes. Nickel plating generates very low residual stresses and does not require a subsequent heat treatment, and it can be applied anywhere in the straight part of the tube. It also allows later access to areas above the section repaired in case of further damage, whereas sleeving does not. An ultrasonic inspection method has been developed to detect axial and circumferential cracks in a nickel-plated region.

14. Successful steam-generator replacements have been accomplished at several PWR plants. The replacement steam generators are expected to have a longer life because of improved designs and materials. The design improvements include elimination of crevices, lower residual stresses, and improved access for secondary-side lancing and chemical cleaning. The improved materials include thermally treated Alloy 690 for the tubes and ferritic stainless steels for the tube-support structures.

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9. BOILING WATER REACTOR CONTAINMENTS

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The boiling water reactor (BWR) containment is designed to contain any release of fission products that may occur during certain design–basis accidents. The containment structure is the final barrier to the release of fission products. This chapter (a) describes the design of the different types of BWR containments that have evolved over the years; (b) discusses the aging stressors, degradation sites and mechanisms, potential failure modes, and inservice inspection requirements for each type of containment; and (c) presents recommendations for better management and mitigation of aging degradation damage in BWR containments.

9.1 Description

All operating BWRs are housed in pressure–suppression containments. The only exception is the Big Rock Point reactor, which has a spherical metal containment. The term *pressure suppression* comes from the fact that steam generated as a result of any loss–of–coolant accident is channeled to a suppression pool, where it is condensed. This prevents the pressure buildup that otherwise would occur in the primary containment. BWR containment pressures, therefore, remain relatively moderate compared to the pressures that may occur in pressurized water reactor (PWR) containments during similar accidents.

Table 9.1[1] lists the 36 operating domestic BWRs, in chronological order of their operating license dates, and presents their respective power rating, construction permit date, and containment type and materials. The oldest BWR is the Big Rock Point plant, built as a demonstration plant and kept in operation for 26 years. The age distribution of operating BWRs based on their operating license dates, is shown in Figure 9.1.

Table 9.1. Containment designs for operating domestic BWR power plants[1]

Nuclear Unit	Power (MWe)	Construction Permit Date	Operating License Date	Containment Design and Materials[a]
Big Rock Point	69	05-31-60	08-30-62	Sphere, Steel
Oyster Creek	620	12-15-64	04-09-59	Mark I, Steel
Nine Mile Point 1	610	04-12-65	08-22-69	Mark I, Steel
Dresden 2	794	01-10-66	12-22-69	Mark I, Steel
Monticello	536	06-19-67	09-08-70	Mark I, Steel
Millstone 1	660	05-19-66	10-07-70	Mark I, Steel
Dresden 3	794	10-14-66	01-12-71	Mark I, Steel
Quad Cities 1	789	02-15-67	10-01-71	Mark I, Steel
Quad Cities 2	789	02-15-67	04-06-72	Mark I, Steel
Pilgrim 1	670	08-26-68	06-08-72	Mark I, Steel
Vermont Yankee	514	12-11-67	02-28-73	Mark I, Steel
Peach Bottom 2	1065	01-31-68	08-08-73	Mark I, Steel

Table 9.1. (continued)

Nuclear Unit	Power (MWe)	Construction Permit Date	Operating License Date	Containment Design and Materials[a]
Browns Ferry 1	1065	05-10-67	12-20-73	Mark I, Steel
Cooper	778	06-05-68	01-18-74	Mark I, Steel
Duane Arnold	538	06-22-70	02-22-74	Mark I, Steel
Peach Bottom 3	1065	01-31-68	07-02-74	Mark I, Steel
Browns Ferry 2	1065	05-10-67	08-02-74	Mark I, Steel
Hatch 1	786	09.30-69	08-06-74	Mark I, Steel
Fitzpatrick	816	05-20-70	10-17-74	Mark I, Steel
Brunswick 2	790	02-07-70	12-27-74	Mark I, Concrete
Browns Ferry 3	1065	07-31-68	08-18-76	Mark I, Steel
Brunswick 1	790	02-07-70	11-12-76	Mark I, Concrete
Hatch 2	795	12-27-72	06-13-78	Mark I, Steel
La Salle County 1	1078	09-10-73	04-17-82	Mark II, Concrete[b]
Susquehanna 1	1050	11-03-73	07-17-82	Mark II, Concrete
Grand Gulf 1	1250	09-04-74	07-82	Mark III, Concrete
La Salle County 2	1078	09-10-73	12-16-83	Mark II, Concrete[b]
WNP-2	1150	03-19-73	12-20-83	Mark II, Steel
Susquehanna 2	1050	11-03-73	03-23-84	Mark II, Concrete
Limerick 1	1055	06-19.74	10-26-84	Mark II, Concrete
Fermi 2	1093	09-26-72	03-20-85	Mark I, Steel
Shoreham	819	04-15-73	07-85[c]	Mark II, Concrete
River Bend 1	940	03-25-77	08-29-85	Mark III, Steel
Perry 1	1205	05-03-77	03-18-86	Mark III, Steel
Hope Creek 1	1067	11-04-74	04-11-86	Mark I, Steel
Nine Mile Point 2	1080	06-24-74	10-31-86	Mark II, Concrete
Clinton 1	950	02-24-76	04-17-87	Mark III, Concrete

a. *Steel* indicates that the primary containment pressure boundary is a thick-walled free-standing steel pressure vessel; *concrete* indicates a thin, steel liner.

b. Prestressed concrete containment; other concrete containments are reinforced concrete.

c. Limited to 5% power.

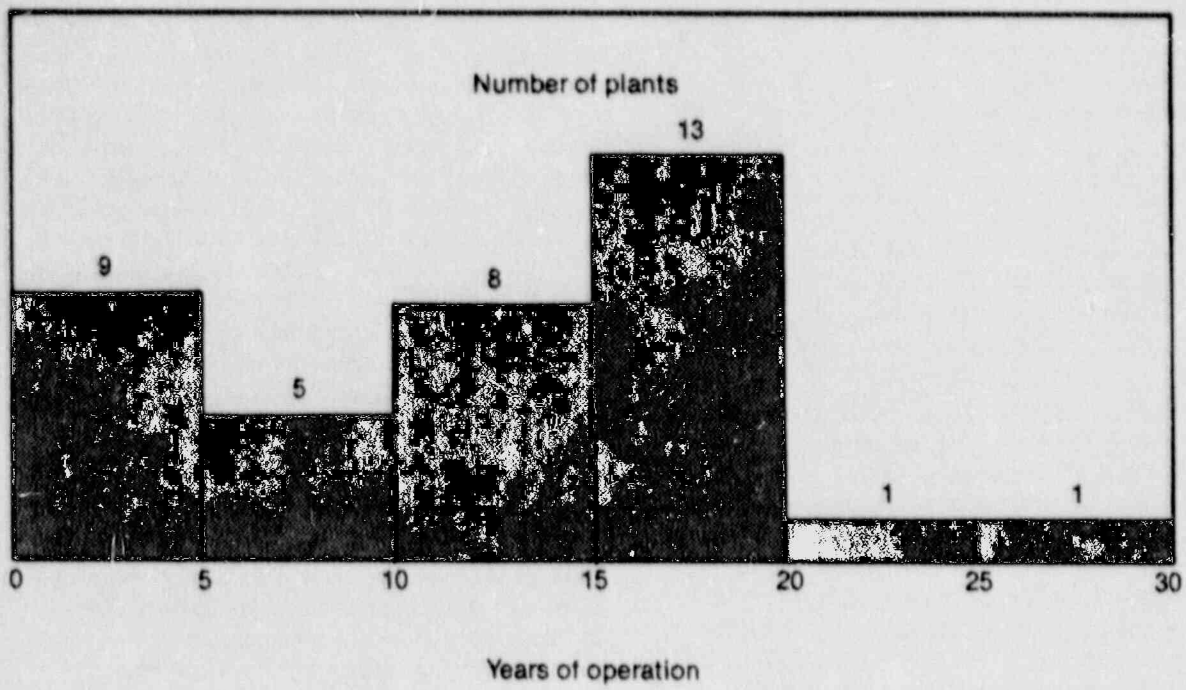

Figure 9.1. Age distribution of operating BWRs based on operating license date.

The BWR pressure suppression containments are of three designs and of three types of construction. The three designs, or generations, are Mark I, Mark II, and Mark III. The three types of construction are metal, reinforced concrete, and prestressed concrete containment, depending on whether the containment is a free-standing metal vessel, or a reinforced or prestressed concrete vessel with metal liner. The distribution of BWR containments by design and construction is shown in Table 9.2.

All pressure-suppression containments consist of a drywell, which contains the reactor pressure vessel, recirculation piping, and other associated piping, and a wetwell or suppression chamber that contains a large volume of water. In the event of a loss-of-coolant accident, the steam that is generated in the drywell enters the suppression chamber through vents (downcomers) and condenses. The suppression pool is also a primary source of water for the emergency core cooling systems. The residual heat removal, core spray, and high-pressure coolant injection systems all take pump suction from the pressure suppression chamber water. Each of these carbon steel lines is part of the containment pressure boundary because they penetrate the pressure suppression chamber.

Table 9.2. Design and construction distribution for BWR containments

Spherical (steel plate)	1
Mark I	
Steel	22
Reinforced concrete	2
Mark II	
Steel	1
Reinforced concrete	5
Prestressed concrete	2
Mark III	
Steel	2
Reinforced concrete	2

The BWR Mark I and Mark II drywells and pressure suppression chambers are completely enclosed in a reinforced concrete reactor building. Technical specifications generally require that the pressure in the reactor building be maintained slightly below atmospheric pressure. BWR Technical Specifications also require the reactor building to be tested for leakage during each refueling cycle to ensure that this pressure can be maintained.[2] The relative humidity in the reactor building is maintained at approximately 30–40%, and the temperatures vary from 13 to 25°C (55 to 77°F) in the winter to 40 to 49°C (105 to 120°F) in the summer.[a]

Specific design characteristics of each BWR containment category (metal, reinforced concrete, and prestressed concrete) are presented in Sections 9.1.1, 9.1.2, and 9.1.3, respectively.

9.1.1 Metal Containments. Of the 26 BWRs with metal vessels as the primary containment, the BWR Mark I and Mark II metal containments (22 and 1, respectively) are contained within a secondary concrete shield wall and a reactor building. The BWR Mark III metal containments (2) are surrounded by a concrete shield building. These structures protect the primary containment from internal missiles (Mark I and II) and external environmental hazards such as severe weather and tornado-generated missiles. All metal containments are made of SA-516 Grade 70 or SA-212 Grade B carbon steel plates. The bellows are made of Type 304 stainless steel. Specific design characteristics of each type of containment are described below.

MARK I Design. Mark I primary containments consist of an inverted light bulb-shaped drywell vessel surrounded at the base by a torus-shaped suppression chamber, as shown in Figure 9.2. The drywell and suppression chamber are connected, typically, by eight vent lines equally spaced around the base of the drywell. The drywell is a free-standing vessel supported at the base by a concrete embedment. The embedded portion of the drywell base metal is not coated. However, the concrete-metal interface is usually sealed to prevent moisture from reaching the embedded drywell base. For example, a polysulfide seal was installed in the Monticello BWR containment.[3]

A reinforced concrete wall [1.2- to 1.8-m (4- to 6-ft) thick], called the secondary concrete shield wall, surrounds the drywell to provide shielding and, in areas where it backs up the drywell, provides additional resistance to deformation and buckling of the shell. A 50- to 75-mm (2- to 3-in.) gap (shown in Figure 9.3) between the drywell and the secondary concrete shield wall allows for thermal and pressure expansion and contraction during normal operation and during design-basis accidents.[4] This gap is usually filled with a compressible fill material during construction of the concrete shield to maintain proper spacing. The fill material was removed after construction of some Mark I containments and left in place at other plants. Moisture can be trapped in the filler material and may cause corrosion of the drywell. Also, the filler material can degrade, and the aggressive chemicals in the material may cause significant corrosion of the drywell. Table 9.3[5] lists the fill materials used in many BWRs. A sand pocket is located at the bottom of the drywell-to-secondary concrete shield wall gap, as shown in Figure 9.3. Moisture may also collect in this sand pocket and cause corrosion problems. However, the gap in some Mark I's is sealed by covering the sandpocket with a galvanized steel plate that is sealed to the drywell shell and the concrete shield wall. Drains remove any moisture that may collect on top of this plate. This prevents any liquid leaking into the gap from entering the sand pocket. Plants with sealed gap are identified in Table 9.3.

Shielding over the top of the drywell is provided by a removable, reinforced concrete shield plug. The drywell head is a flanged, removable closure for access to the reactor pressure vessel during refueling. The area above the drywell flange is filled with water to the refueling platform during refueling.

The pressure suppression chamber is a carbon steel pressure vessel in the shape of a torus below and encircling the drywell, and is reinforced at each joint by an internal ring beam. It is supported vertically at each joint by columns and a saddle support, as shown in Figure 9.4. The lubrite baseplates between the support columns and the torus provide a low-friction surface to allow expansion of the torus during heatup, cooldown, and pressure testing. Typically, eight equally spaced vent pipes form a connection between the drywell and the pressure suppression chamber. The vent pipes have single- or double-ply, Type 304 stainless steel expansion bellows to accommodate differential motion between the drywell and the suppression chamber (as shown in Figure 9.2).[6] The typical thickness of one ply is 2.0 mm (0.08 in.). Jet deflectors installed in the drywell at the entrance of each vent pipe prevent possible damage to the vent pipes from jet forces that might accompany a pipe break in the drywell. The vent pipes exhaust into a continuous vent header, from which downcomer pipes extend into the suppression chamber pool below the minimum water level.

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a. J. M. McGhee, personal communication, EG&G Idaho, March 1988.

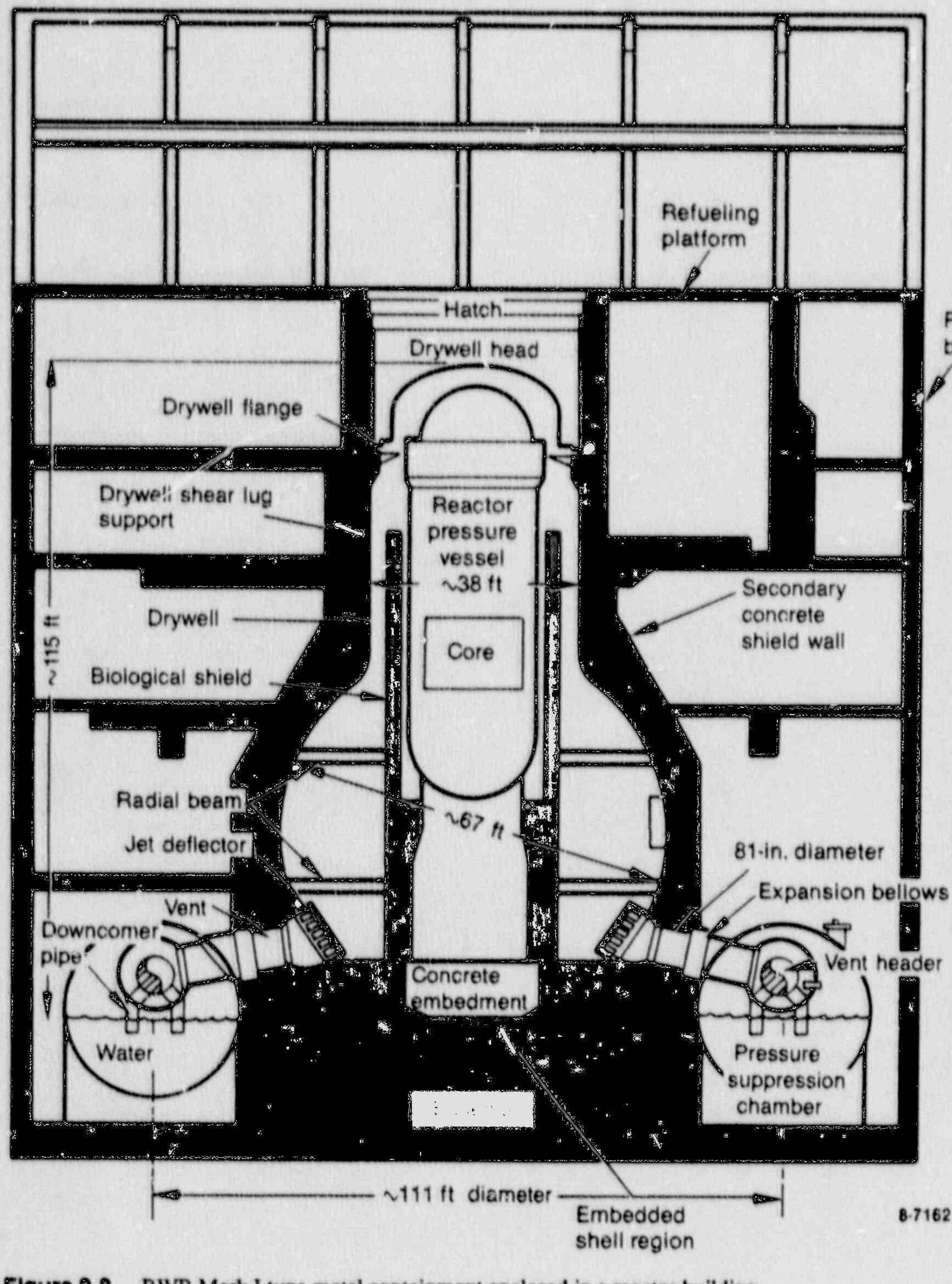

Figure 9.2. BWR Mark I type metal containment enclosed in a reactor building.

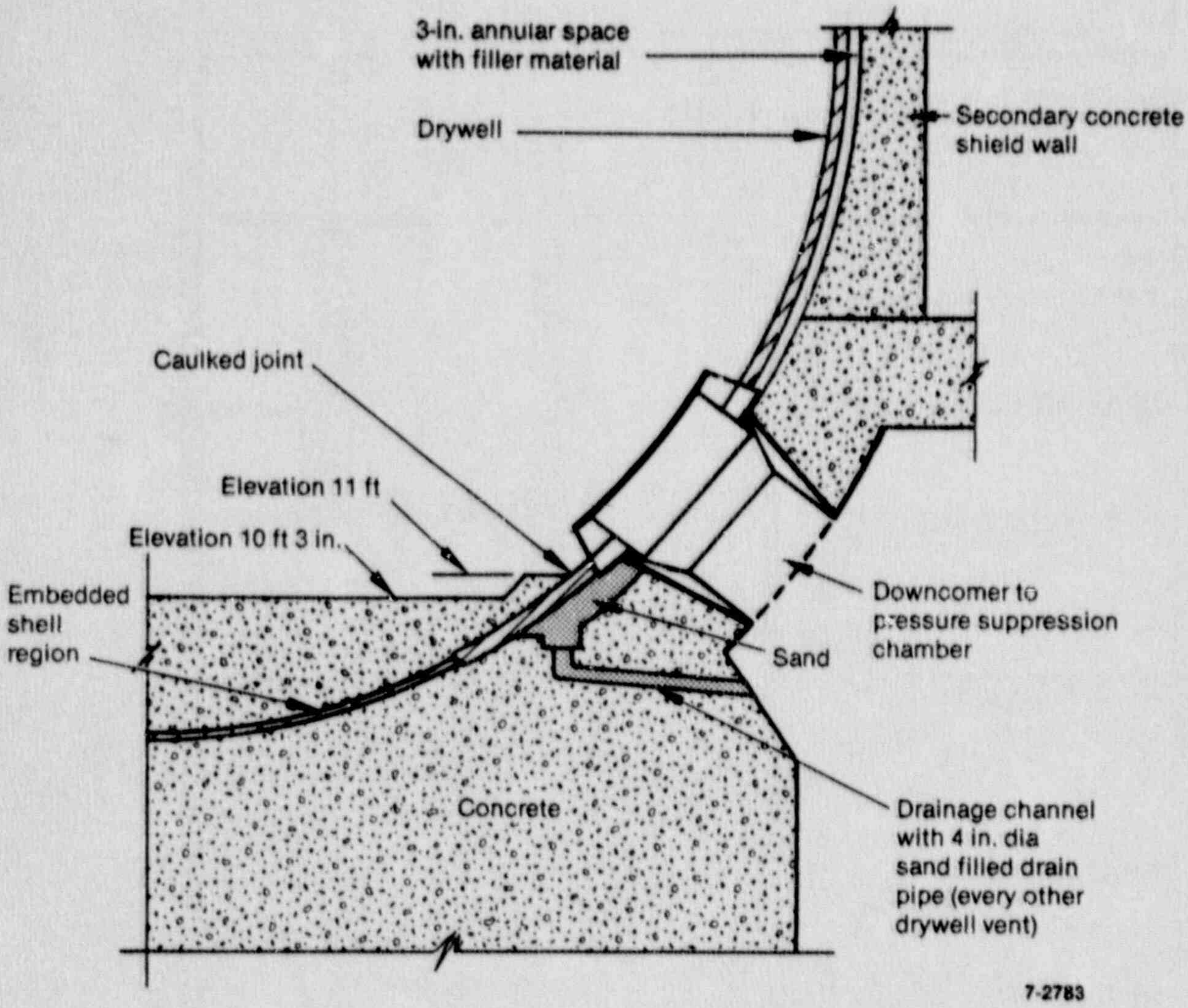

Figure 9.3. BWR Mark I drywell base, concrete shield wall, and sand pocket.

Table 9.3. BWR Mark I fill materials[5]

Nuclear Units	Fill Material	Fill Material Removed as of 1/6/87	Comments
Oyster Creek	Firebar D and fiberglass	No	Gap not sealed
Nine Mile Pt 1	Fiberglass foam	—	Gap sealed, drain provided
Dresden 2	Polyurethane foam	No	—
Monticello	Polyethylene strips	Yes	Gap sealed, drain provided
Millstone 1	—	Yes	No thinning noted. Gap not sealed
Dresden 3	Polyurethane foam (burned up)	No	Gap not sealed
Quad Cities 1	Polyurethane foam	No	Gap not sealed
Quad Cities 2	Polyurethane foam	No	Gap not sealed
Pilgrim 1	Ethafoam	Yes	Gap sealed, drain provided
Vermont Yankee	Styrofoam	No	Probably not sealed
Peach Bottom 2	Polyethylene strips	No	Gap sealed, drain provided
Browns Ferry 1	Polyurethane	No	Gap not sealed
Cooper	Urethane foam	No	Gap not sealed
Duane Arnold	Polyurethane foam	Yes	Gap sealed, drain provided
Peach Bottom 3	Polyethylene strips	No	Gap sealed, drain provided
Browns Ferry 2	Polyurethane	No	Gap not sealed
Hatch 1	Ethafoam	Yes	Gap sealed, drain provided
Fitzpatrick	Ethafoam	Yes	Gaps sealed, drain provided
Brunswick 2	NA	NA	Reinforced concrete containment
Browns Ferry 3	Polyurethane	No	Gap not sealed
Brunswick 1	NA	NA	Reinforced concrete containment
Hatch 2	Ethafoam	Yes	Gap sealed, drain provided
Fermi 2	Foam	No	Gap not sealed
Hope Creek 1	Fiberglass	No	—

NA = Not Applicable.

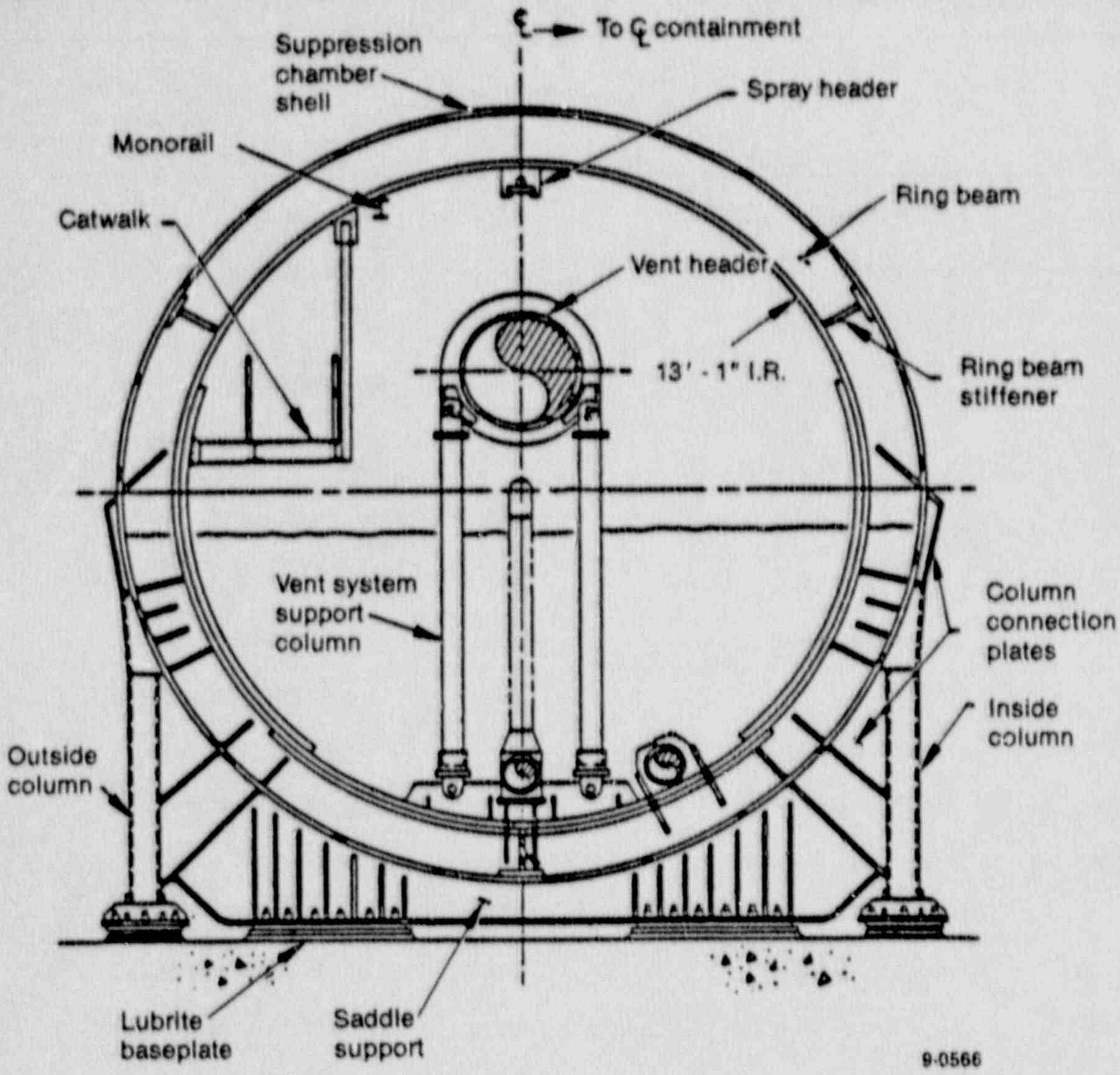

Figure 9.4. Mark I pressure suppression chamber cross section showing mounting and supports.

Table 9.4 presents the dimensions of a Mark I containment structure.[6] The dimensions will vary among different plants, owing to different design characteristics. For example, the diameter of the spherical portion of the drywell for the Hope Creek 1 Plant is 20.7 m (68 ft), whereas in the Browns Ferry Plants it is 18.6 m (61 ft). Design parameters for a Mark I containment are presented in Table 9.5.[7] The free volume of the containment is determined to contain the total postulated energy release within the containment without loss of function and violation of the pressure boundary during a design–basis loss–of–coolant accident.

The interiors of the drywell and suppression chamber are generally painted with a zinc–rich primer coating to help resist corrosion. Red–lead, modified phenolic, and epoxy coatings have also been employed; the epoxy has been found more durable than the red lead.[8] A red–lead coating generally has been applied on the outside surface of the drywell and pressure suppression chamber. To further guard against the potential effects of corrosion in some of the recent Mark I designs, Hope Creek 1, for example, the thickness of the drywell shell has been increased by 1.6 mm (0.06 in.) beyond minimum design thickness.[6]

Prior to each startup, the primary containment is purged with pure nitrogen until the atmosphere contains less than 4% oxygen by volume. This nitrogen inerting is to control oxygen and prevent the possibility of ignition of a hydrogen and oxygen mixture that may occur following a postulated accident.

Table 9.4. Dimensions of a Mark I metal containment (1 in. = 25.4 mm)

Drywell	
Drywell head diameter	27 ft 2 in.
Cylindrical section diameter	32 ft
Spherical section diameter	63 ft
Drywell height (overall)	108 ft 9 in.
Wall–plate thickness	
Drywell head	1 7/16 in.
Cylindrical section	1 7/16 in.
Spherical section	3/4 in.
Vent System	
Vent pipes	
Number	8
Internal diameter	4 ft 9 in.
Wall thickness	0.25 in.
Vent header internal diameter	3 ft 6 in.
Downcomer pipes	
Number	48
Internal diameter	2 ft
Submergence below suppression pool water level	4 ft
Pressure Suppression Chamber	
Chamber inner diameter	25 ft 8 in.
Torus major diameter	98 ft 8 in.
Wall–plate thickness	
Above horizontal centerline	0.587 in.
Below horizontal centerline	0.658 in.
Penetration locations	1 in.

Containment penetrations are designed to withstand the normal environmental conditions that prevail during plant operation and to retain their integrity during and following postulated accidents. Penetrations for high–energy pipe lines have two–ply Type 304 stainless steel expansion bellows to accommodate thermal movements between the pipe and containment shell. These expansion bellows serve as part of the primary containment. The high–energy pipe lines include the reactor core isolation cooling steam, high–pressure coolant injection, feedwater, residual heat removal, main steam lines, and several other process pipes. A guard pipe is installed between the pipes and bellows to prevent damage to the bellows during an unlikely pipe–rupture event. Insert plates are used to reinforce the drywell near penetrations.

Table 9.5. Principal design parameters of a Mark I containment[7]

Drywell	
Free volume	169,000 ft^3
Design temperature	340°F
Operating temperature	135°F
Design internal pressure	62 psig
Design–basis accident maximum pressure	48.1 psig
Pressure Suppression Chamber	
Free volume	133,500 ft^3
Pool water volume (max)	122,000 ft^3
Pool water volume (min)	118,000 ft^3
Design temperature	310°F
Operating temperature of water	95°F
Design–basis accident maximum water temperature	209°F
Design internal pressure	62 psig
Design–basis accident maximum pressure	25.5 psig

MARK II Design. The only Mark II metal containment is the Washington Nuclear Project No. 2 containment, shown in Figure 9.5.[9] The Mark II design differs from the Mark I design in that the overall shape of the free–standing steel vessel is a frustum of a cone, set on a cylinder rather than an inverted lightbulb, and the drywell is directly above the suppression chamber (hence the term "over and under configuration" that is often used), rather than separated, as in the Mark I torus design. The drywell and pressure suppression chamber together are enclosed by a free–standing carbon steel vessel supported by a concrete embedment at the base and surrounded by a secondary concrete shield wall with a 50–mm (2–in.) expansion gap separating the two. Shielding over the top of the drywell is provided by a removable, reinforced concrete shield plug, a design similar to the Mark I.

The pressure suppression chamber is a steel cylinder pressure vessel, having an approximate diameter of 20 m (65 ft 9 in.) and a height of 12.8 m (42 ft). The dividing floor between the drywell and the suppression chamber forms the top closure. An ellipsoidal steel head forms the bottom closure. The suppression chamber is designed in combination with the drywell for thermal and seismic loads. The dividing floor is designed for a differential pressure of 0.17 MPa (25 psi), as well as for the normal floor loading, which includes piping and equipment loads.

The drywell is formed by the cone frustum described above. The diameter of the bottom of the cone is 20 m (65 ft 9 in.) where it meets the top of the suppression–chamber cylinder. The diameter at the top of the cone where the closure head bolts down is approximately 9.7 m (31 ft 8 in.). The height of the cone is approximately 23.8 m (78 ft). The bottom closure of the drywell is the reinforced concrete floor that separates the drywell and the suppression chamber. The top closure head is a steel cap about 9.7 m (31 ft 8 in.) in diameter that bolts to a steel flange attached to the top of the drywell. The overall height of the containment, including drywell, suppression chamber, and bottom and top closures is about 50.3 m (165 ft). Design parameters for a Mark II containment are presented in Table 9.6.[9]

The drywell atmosphere is vented into the suppression chamber through a series of downcomer pipes penetrating the drywell floor. Each vent opening is shielded by a steel deflector plate to prevent overloading any single vent by direct flow from a pipe break to that particular vent. Prior to each startup, the primary containment is purged with pure nitrogen until the atmosphere contains less than 4% oxygen by volume.

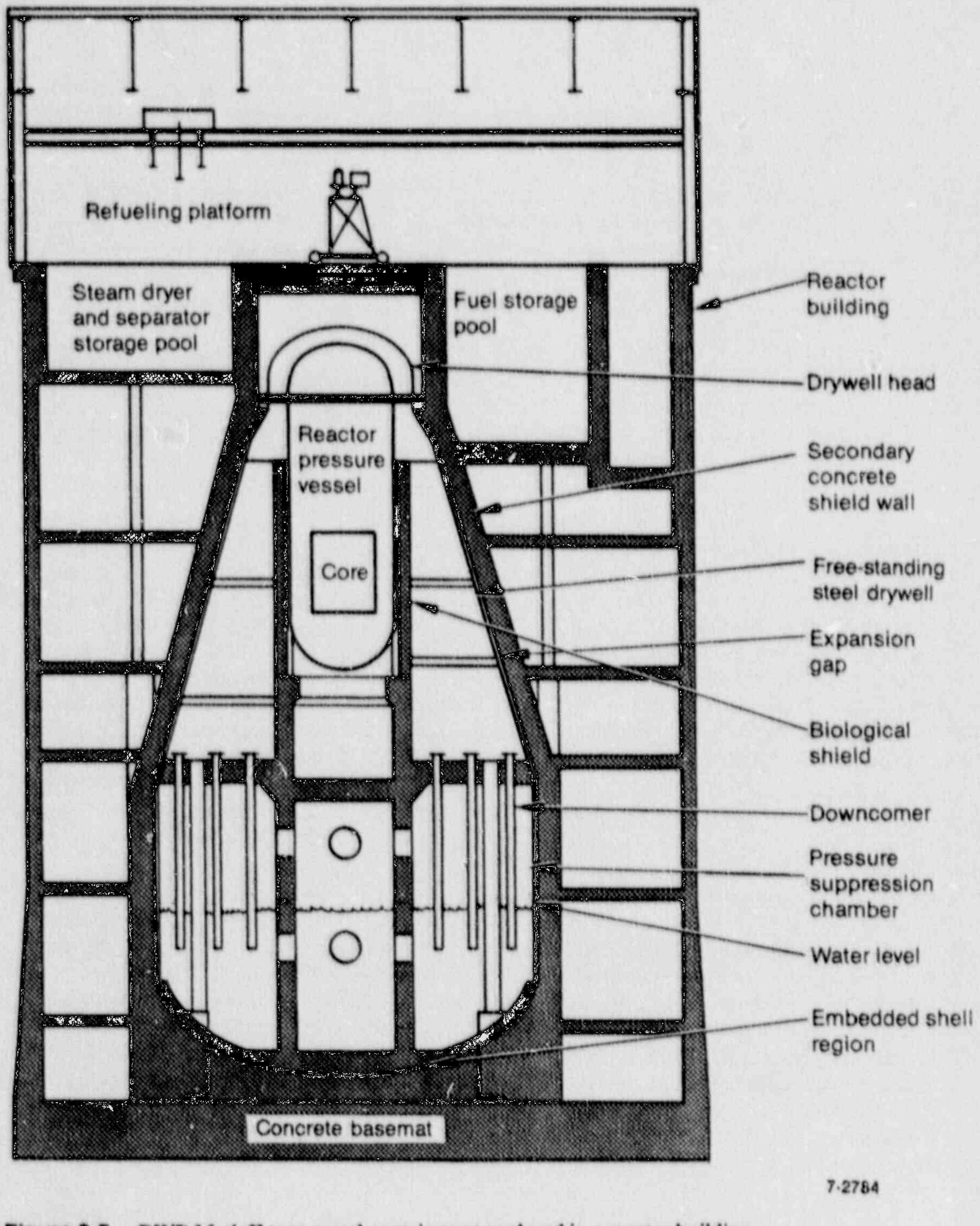

Figure 9.5. BWR Mark II type metal containment enclosed in a reactor building.

Table 9.6. Design parameters of a Mark II containment[9]

Drywell	
Free volume	202,242 ft^3
Design temperature	340°F
Operating temperature	135°F
Design internal pressure	45.0 psig
Design–basis accident maximum pressure	37.2 psig
Pressure Suppression Chamber	
Free volume (min)	144,166 ft^3
Pool water volume (min)	108,387 ft^3
Design temperature	275°F
Operating temperature of water	95°F
Design internal pressure	45.0 psig
Design–basis accident maximum pressure	28 psig

MARK III Design. Figure 9.6 shows the Mark III containment design with a steel containment vessel, consisting of four main components: concrete drywell, suppression pool, containment vessel, and concrete shield building. Only two operating domestic BWRs have Mark III steel containments: the River Bend and Perry 1 plants. Design information for the Mark III steel containment described herein came from the River Bend Final Safety Analysis Report.[10]

The drywell is a cylindrical, reinforced concrete structure with a removable steel head to allow vertical access to the reactor vessel for refueling or maintenance. The suppression pool is an open–top structure located partly inside the drywell, and with the inner boundary formed by the cylindrical concrete weir wall. The major part is outside the drywell between the outer drywell wall and the inner containment wall. A system of horizontal vents connect the drywell and containment pool volumes. The containment vessel is made of carbon steel clad with stainless steel up to about one foot above the normal suppression pool level. This cladding provides a maintenance–free surface that can be easily decontaminated, and eliminates the need for a protective coating.

The primary containment vessel is a free–standing, vertical, cylindrical steel pressure vessel with an ellipsoidal head and a flat bottom steel liner plate. The cylindrical shell has horizontal external stiffeners and is anchored five feet into the concrete mat foundation. The flat–bottom liner plate is approximately 19–mm (0.75–in.) thick and is continuously supported by the concrete mat. The liner plates are welded to embedded steel members in the mat, and serve as a leaktight membrane for the containment vessel. There is a 1.5–m (5–ft) annulus between the containment vessel and the shield building. The annulus provides easy access to the steel containment vessel for inspection, and also functions as a secondary containment barrier by providing a plenum for collecting and filtering radioactive leakage from the containment in the event of a loss–of–coolant accident. Piping penetrations for high–energy pipe lines from the drywell that traverse the primary containment are contained within guard–pipe assemblies.

The River Bend Station Mark III steel containment structure measures about 36.6 m (120 ft) in diameter, 56.7 m (186 ft) in height, including the head, and 44.5 mm (1.75 in.) in wall thickness. Inside the steel structure is a drywell 21 m (69 ft) in diameter and containing the 19.5–m– (64–ft–) diameter weir wall. The suppression pool fills the bottom 6 m (20 ft) of the containment structure. The Perry 1 Nuclear Plant containment has similar dimensions. Typical design parameters for Mark III containments are presented in Table 9.7.[10]

Steel Sphere Containment.[11] The Big Rock Point plant is the only operating BWR having a spherical, steel containment. There is no shield building at this plant. The containment sphere is a vessel 39.6 m (130 ft) in diameter extending 8.2 m (27 ft) below grade. The containment sphere also serves as a reactor building for housing the steam

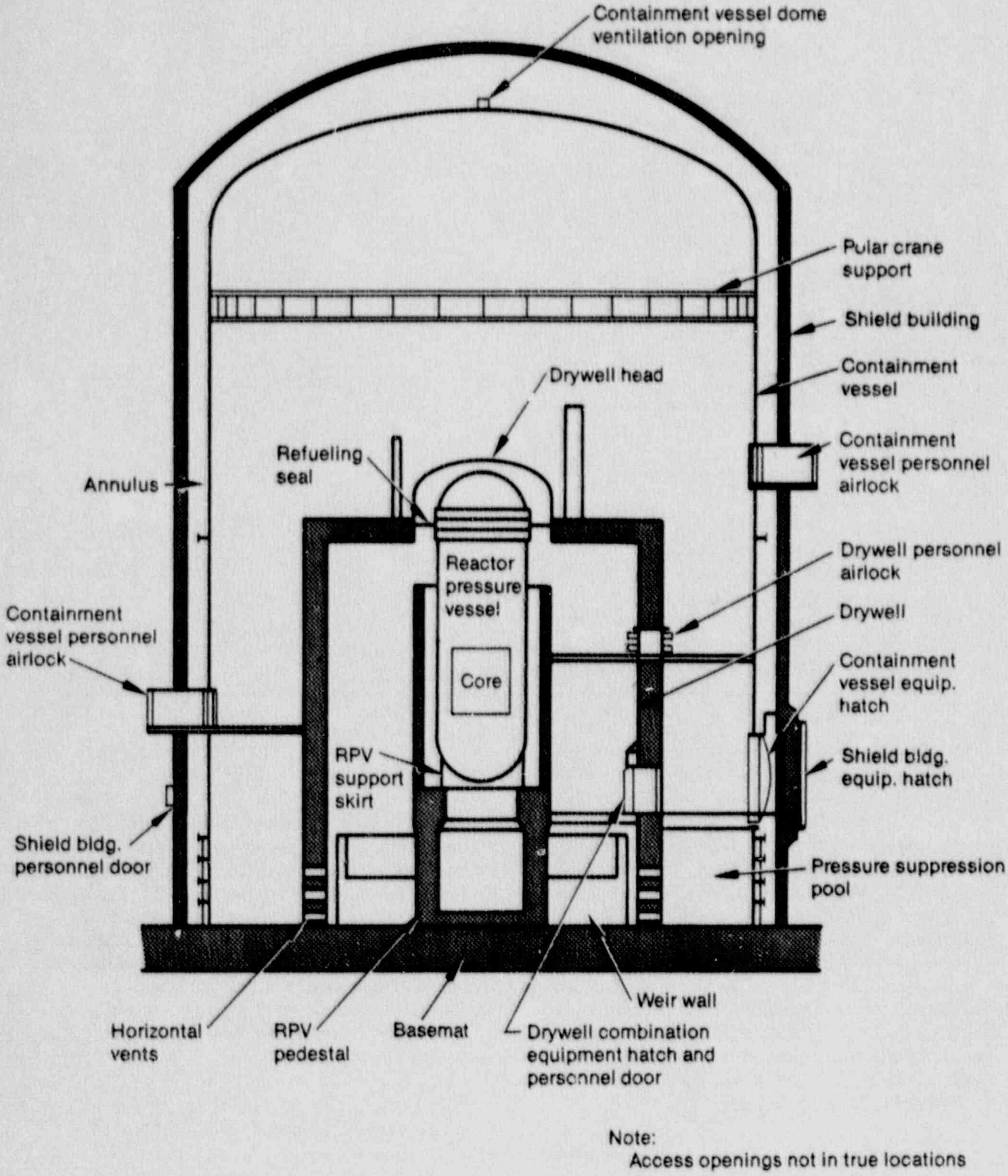

Figure 9.6. BWR Mark III type metal containment enclosed in a concrete shield building.

Table 9.7. Principal design parameters of a Mark III metal containment[9]

Drywell	
Free volume	236,196 ft^3
Design temperature	330°F
Operating temperature	135°F
Design internal pressure (differential)	25 psi
Design external pressure (differential)	20 psi
Design–basis accident maximum internal pressure (differential)	19.2 psi
Pressure Suppression Chamber	
Free volume	127,930 ft^3
Pool water volume (min)	124,726 ft^3
Design temperature	185°F
Operating temperature of water	100°F
Design–basis accident maximum pressure	7.6 psig
Containment Vessel	
Free volume	1,191,590 ft^3
Design temperature	185°F
Operating temperature	90°F
Design internal pressure	15 psig
Design external pressure (differential)	0.6 psi
Design–basis accident maximum pressure	7.6 psig
Design–basis accident maximum temperature	141°F

generating system and auxiliaries. Principal design parameters for the containment vessel are shown in Table 9.8.

The exposed exterior surface of the sphere is insulated with a cork mastic coating sprayed to a dry thickness of 9.5 mm (0.38 in.), and protected by two coats of acrylic resin base emulsion. The insulation is provided to prevent excessive temperature inside the containment vessel caused by solar radiation and to reduce loss of heat during winter. The insulation also provides atmospheric corrosion protection and reduces inside surface condensation. Although temperature control is primarily for operational purposes, it also is intended to maintain ductility of the metal shell and prevent potential brittle fracture.

9.1.2 Reinforced Concrete Containments.

There are eight operating domestic BWR plants with reinforced concrete containments. These include two Mark I designs, Brunswick 1 and 2; five Mark II designs, Susquehanna 1 and 2, Limerick 1, Nine Mile Point 2, and Shoreham; and two Mark III designs, Grand Gulf 1 and Clinton 1.

There are very few differences in the design configurations between metal (as described in Section 9.1.1) and concrete containments. The major difference, however, is that in the metal containment the primary containment vessel is surrounded by the secondary shield wall; whereas, in the concrete containment there is a steel liner on the concrete wall. The steel liner also acts as an impervious inner barrier. Since the reinforced concrete containment designs do not differ significantly from metal containments, only brief design descriptions will be provided here.

Mark I Design. The drywell consists of two, reinforced concrete, steel-lined (ASTM–A516 Gr.60), right cylinders oriented vertically and joined by a truncated conical section. The bottom of the drywell is another conical section with a solid cylindrical base pedestal. The drywell is closed by a continuous steel dome bolted to the top. When joined together, the

Table 9.8. Principal design parameters for BWR spherical metal containment[10]

Design internal pressure	27 psig
Design external pressure (coincident with dead load only)	0.5 psig[a]
Design temperature rise (coincident with design internal pressure)	190°F
Design maximum temperature	235°F
Wind Load (60 mph)	ASA Std. A58.1
Without snow load (basic wind pressure)	30 psf
Snow load	ASA Std. A58.1
Maximum at top	40 psf

a. External pressure does not govern; with shell thickness designed to withstand 27 psig internal pressure, safe external pressure coincident with dead load only is 1.22 psig.

configuration of the reinforced concrete drywell shown in Figure 9.7 is similar to the conventional steel containment light bulb shape.[12] The overall height from the top of the foundation mat to the drywell head flange connection is approximately 33.8 m (111 ft).

The pressure suppression chamber is a steel–lined, circular, reinforced concrete shell with a major diameter of 33.2 m (109 ft). The suppression chamber comprises 16 interconnected cylindrical sections with 8.8 m (29 ft) internal diameters. The liner material is ASTM–A516 Gr.60 steel, 9.5 mm (0.38 in.) thick.

The welded seams in the drywell and pressure suppression chamber liners, which are inaccessible after completion of construction or are under water, are covered by leak chase channels. The leak chase channels are simply metal channels embedded in the concrete behind the liner welds. These channels permit monitoring of leaktightness during normal operation by pressurizing local areas with air and also permit collection of suppression chamber water if the liner weld leaks. If leak chase channels are used for inservice inspection requirements, they must be tested in accordance with 10 CFR 50, Appendix J, Type B leak tests.[13]

The drywell and the pressure suppression chamber are supported on the same basemat foundation. An expansion joint between the bottom of the suppression chamber and the mat foundation allows for radial expansion of the suppression chamber. The suppression chamber has eight symmetrically located vent openings corresponding to the vent openings in the drywell, similar to the steel containment design. The drywell and pressure suppression chamber are completely enclosed in a reactor building, as discussed above.

The design parameters of a primary containment system are provided in Table 9.9.

Mark II Design. The primary and secondary containments for the Mark II reinforced concrete containment design, shown in Figure 9.8,[14] are similar to the Mark II metal containment design shown in Figure 9.5; the major difference is that the drywell of the metal containment is a free–standing steel vessel, whereas the drywell of the reinforced concrete containment is a steel–lined reinforced concrete vessel. The drywell shapes also are similar and consist of a frustum of a cone closed by a dome. The pressure suppression chamber is a cylindrical, steel–lined, reinforced concrete vessel located below the drywell. The liner welds in the drywell and pressure suppression chamber that are inaccessible after construction are enclosed in leak chase channels, as described above. The design parameters of a Mark II reinforced concrete design are similar to those of the Mark II metal containment presented in Table 9.6. The drywell and the pressure suppression chamber are completely enclosed within a reactor building.

Mark III Design. The basic configuration of the Mark III concrete containment shown in Figure 9.9[15] is similar to the Mark III metal containment, shown in Figure 9.6; the major difference is that the free–standing steel containment vessel (Figure 9.6) has been replaced by a steel–lined, reinforced concrete containment vessel. At the Clinton plant, there is also

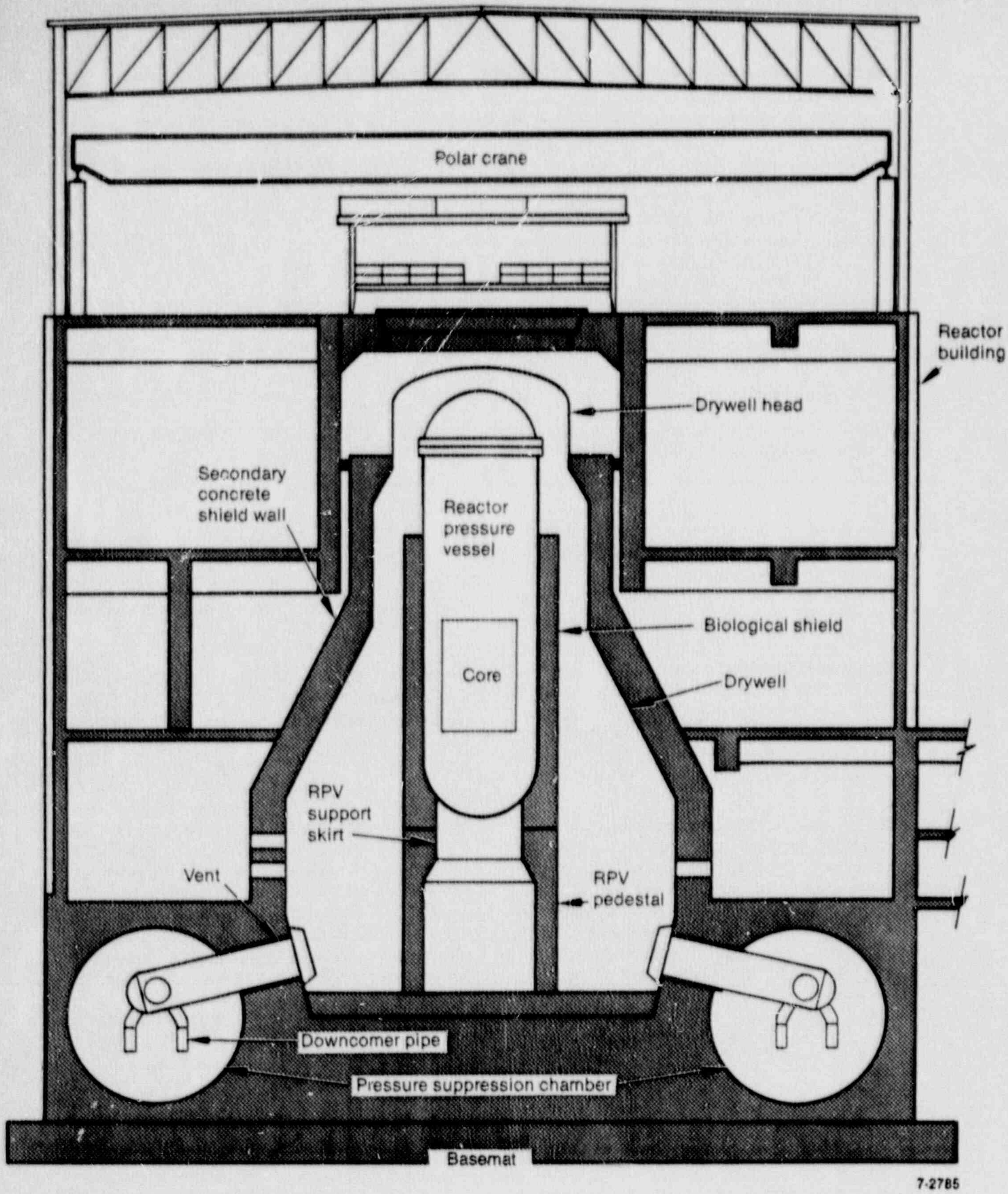

Figure 9.7. BWR Mark I type reinforced concrete containment enclosed in a reactor building.

Table 9.9. Design parameters and characteristics of a Mark I concrete containment[12]

Drywell	
Free volume (including vent system)	164,100 ft^3
Design temperature	300°F
Internal design pressure	62 psig
External design pressure	2 psig
Pressure–Suppression Chamber	
Air volume (min)	124,000 ft^3
Air volume (max)	134,600 ft^3
Pool water (min)	87,600 ft^3
Pool water (max)	89,600 ft^3
Design temperature	220°F
Design internal pressure	62 psig
Design external pressure	2 psig

a steel secondary containment building that surrounds the concrete containment vessel.[a] The Mark III reinforced–concrete containment consists of a flat circular foundation mat, a right circular cylinder for walls, and a hemispherical dome. The cylindrical wall, dome, and foundation mat are constructed of cast–in–place conventionally reinforced concrete. The internal surface of the containment is completely lined with welded steel plate. The suppression pool area of the containment liner is fabricated from stainless steel or carbon steel clad with stainless steel, and above the suppression pool the liner is 6.4–mm (0.25–in.) carbon steel. The basemat liner is also stainless steel or carbon steel clad with stainless steel. The liner welds that are inaccessible after construction are enclosed in leak chase channels, as described in Section 9.1.2. Typical design parameters of the Mark III reinforced concrete containment are similar to those of the Mark III metal design listed in Table 9.7.

9.1.3 Prestressed Concrete Containments.

The La Salle County Units 1 and 2 are the only operating domestic BWRs with prestressed concrete containment structures.[16] The design of the Mark II prestressed concrete containment structures is similar to the Mark II reinforced concrete (Figure 9.8) and metal containment (Figure 9.5) designs. The suppression system is the over–and–under configuration similar to that shown in Figure 9.8, with the drywell a frustum of a cone, located directly above the circular cylinder suppression chamber, and the drywell atmosphere vented into the suppression chamber through a series of downcomer pipes penetrating the drywell floor. The primary containment consists of a steel dome head and posttensioned concrete wall standing on a basemat of reinforced concrete. The inner surface of the containment is lined with steel plate, which acts as a leaktight membrane. The liner welds that are inaccessible after construction are enclosed in leak chase channels.

The wall of the primary containment is prestressed using parallel lay and ungrouted type tendons, each composed of button–headed wires and end–anchorage hardware. There are 188 horizontal tendons and 120 meridional tendons used in the wall of the La Salle plants. There are three buttresses (end–anchor points) for the horizontal tendons, which are equally spaced around the containment, and each horizontal tendon is anchored at buttresses 240 degrees apart, bypassing the intermediate buttress [except for the horizontal tendons in approximately the top 8 m (26 ft), which travel completely around the containment and start and end on the same buttress]. One–half of the meridional (vertical) tendons terminate at the midheight of the containment wall. One–quarter of the meridional tendons are anchored in the refueling floor above the reactor. The rest of the meridional tendons are anchored to the drywell head support ring. All the meridional tendons are anchored at their lower elevation at the underside of the base slab. The tendons are placed inside

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a. J. M. McGhee, personal communication, EG&G Idaho, April 1989.

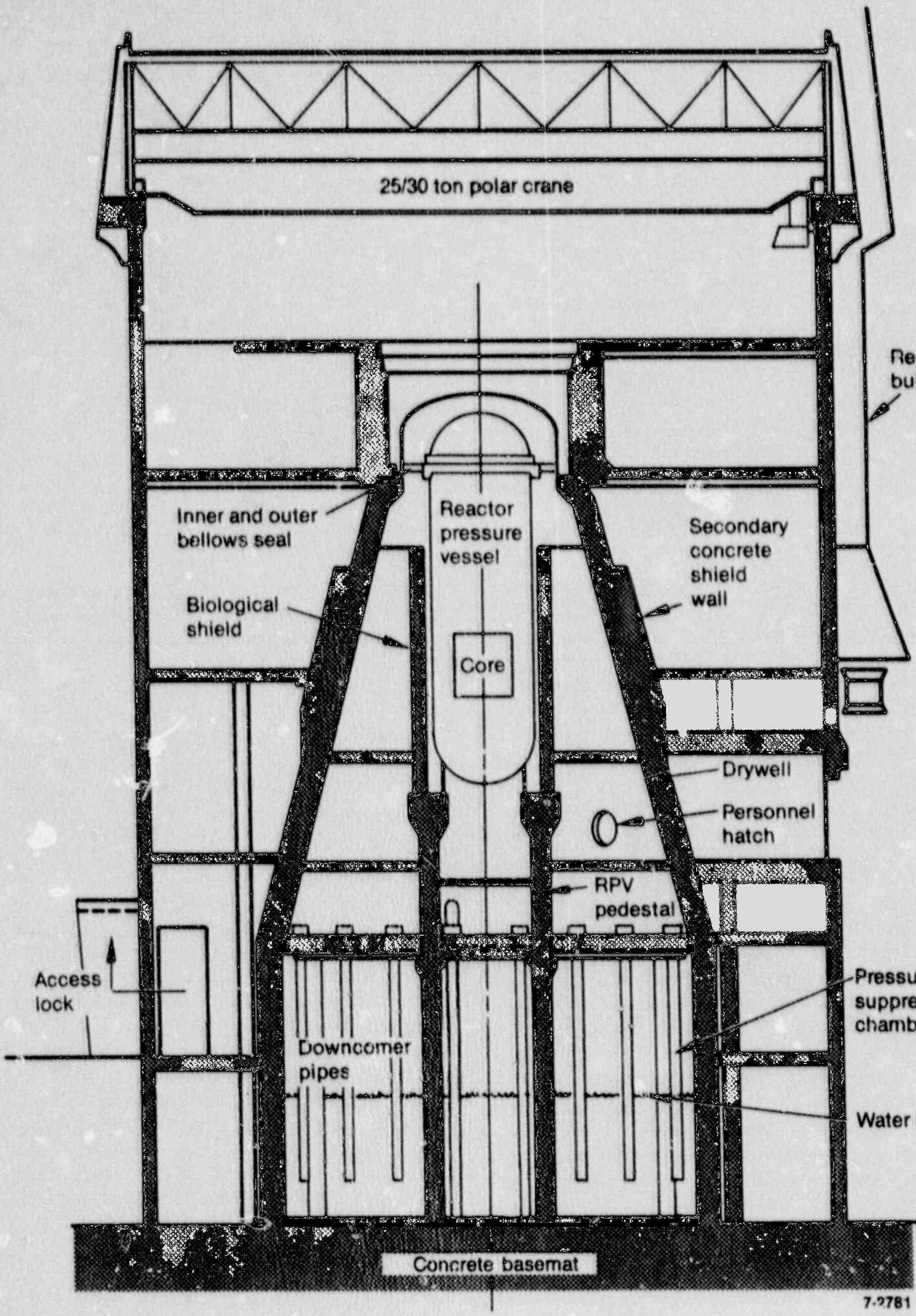

Figure 9.8. BWR Mark II type reinforced concrete containment enclosed in a reactor building.

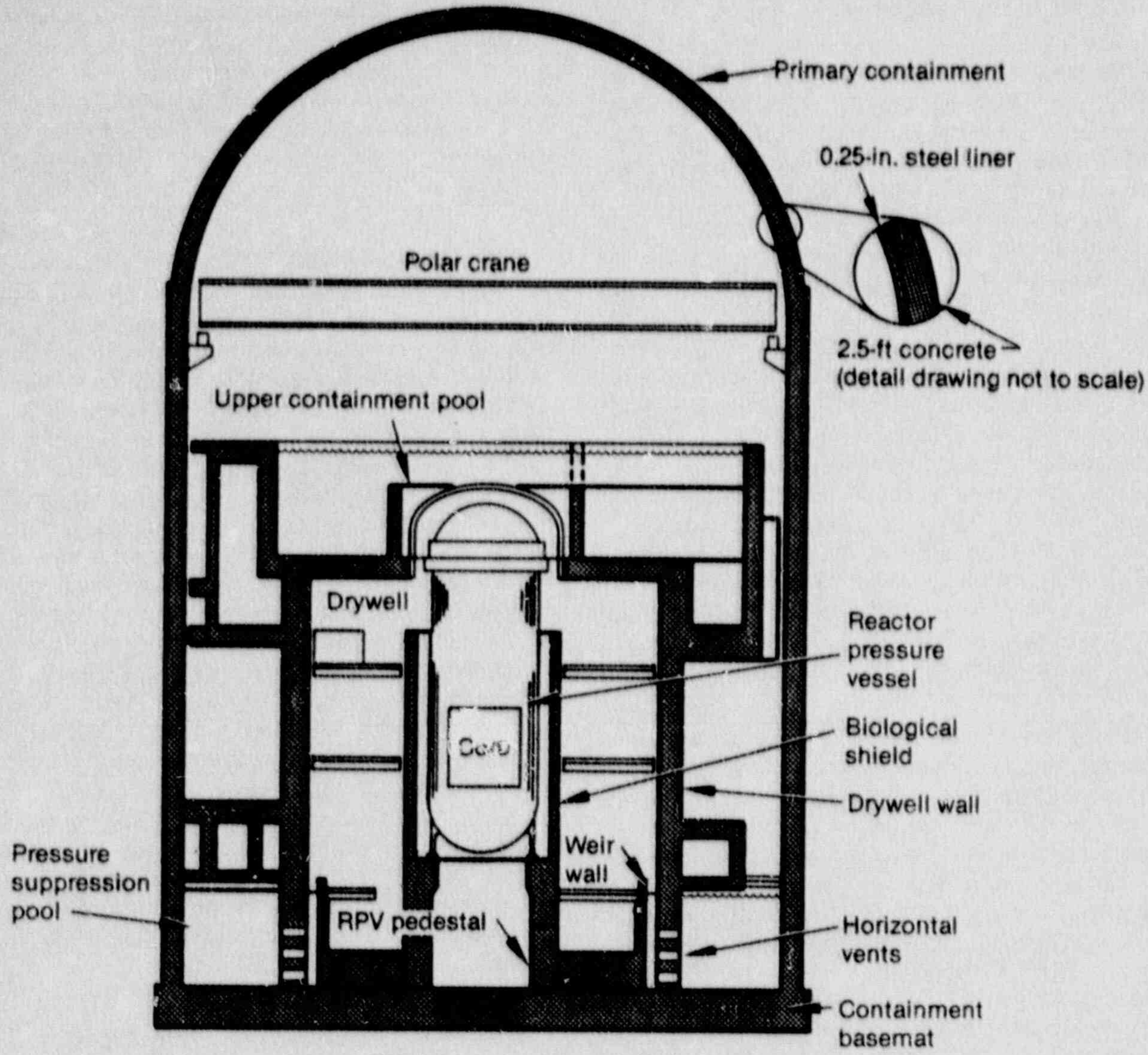

Figure 9.9. BWR Mark III type reinforced concrete containment.

conduits embedded in the concrete and are protected by corrosion-preventive grease. The corrosion-preventive grease used at the La Salle County plants is called Visconorust™ and meets ASTM Standards D-287 for specific gravity, D-992 for water soluble nitrates, and D-512 for water soluble chlorides and for water soluble sulfides.[a]

a. D. Szumski, private communication, La Salle County Nuclear Station, 1989.

9.2 Stressors

Internal and external environments are the major stressors acting on BWR containments and cause occasional corrosion of the metal containments and the metal liners in the concrete containments. Additional stressors act during testing and operation and include cyclic loads on the containment vessels, which cause fatigue damage. The identified stressors for metal containments are discussed in Section 9.2.1, and for concrete containments in Section 9.2.2.

9.2.1 Metal Containments

Internal Environment. The normal operating pressure in BWR containments is in the range of -2 to +2 psig, and the normal operating temperatures for the drywell and suppression pool are usually in the range of 54 to 66°C (130 to 150°F) and 10 to 43°C (50 to 110°F), respectively. However, local temperatures within the drywell may vary significantly with elevation; especially if there is inadequate ventilation in the drywell.[17,18] For example, temperatures of 56°C (132°F) and 106°C (222°F) were measured at the 17– and 27–m (54– and 89–ft) elevations, respectively, in one plant. The drywell wall at 27–m elevation will be less susceptible to corrosion because the higher temperatures at that elevation will keep it dry. The relative humidity in the BWR containments is in the range of 40 to 60%, which is higher than normally found in PWR containments, because of the presence of water in the suppression pool. The humidity level in the suppression chamber may be as high as 90%. The oxygen content inside the Mark I and II containments is maintained at less than 4% by volume.

The presence of water in the suppression pool can increase the susceptibility of the submerged portions of the metal surfaces to corrosion. Therefore, limits are set on the water quality in the pool. Water quality limits are also maintained because the water in the suppression pool is a backup supply or heat sink for several portions of the emergency core cooling system following an accident. Typical water quality limits include a maximum conductivity of 5 micromhos/cm, pH in the range of 6.5 to 8.5, and chlorides in the range of 1 to 500 ppb.[a] A concentration of chlorides in the upper range provides better protection against microbially influenced corrosion. The concentration of dissolved oxygen is normally in the range of 3000 to 5000 ppb. This high level of oxygen is likely to aid the corrosion of any unprotected submerged surfaces, that is, uncoated surface areas or surface areas where the coating has failed. Some plants with Mark I suppression chambers used potassium chromate in the past as a corrosion inhibitor[19] to reduce these problems. However, there are currently no Mark I plants using chromates to inhibit corrosion.[b]

The regions of the metal containments at the core elevation will be exposed to the largest neutron fluences. The transition region from the cylindrical to spherical portions of the drywell in a Mark I containment will experience a maximum neutron fluence of approximately 10^{14} n/cm^2 by the end of the 40–year license period.

External Environment. All BWR metal containments are protected from harsh exterior environments (wide temperature variations, rain, freezing and thawing, etc.) by concrete reactor or concrete shield buildings, with the exception of the Big Rock Point metal sphere. However, corrosive environments are the main stressors acting on the outside surfaces of the Mark I and Mark II metal containments. One of the factors contributing to the formation of a corrosive environment is the presence (in some plants) of compressible material in the gap between the drywell and the secondary shield wall. As discussed above, the compressible material has not been removed from the gap at many plants. Some of these materials are capable of absorbing moisture or of producing corrosive products if degraded. Also, some of these compressible materials can ignite easily and burn vigorously. Therefore, a mishap may ignite these materials and produce corrosive and toxic oxides of nitrogen, together with other toxic gases and corrosive products, that are harmful to metals.[20] These corrosive products cannot be removed easily from the gap (which is relatively inaccessible because of its small size) and if they are present should be considered as stressors.

Another factor contributing to the corrosive external environment is the presence of faulty bellows at the drywell–to–cavity seals, which allow water to leak into the gap between the drywell and the secondary shield during refueling.[4] The compressible fill materials absorb this moisture and create conditions favorable to corrosion. In some metal containments, the gap is not sealed at the bottom and the leaking water will flow into the sand pockets located near the concrete floor of the drywell. The wet sand also provides a corrosive environment against the containment steel. In addition, the wet sand is capable of supporting microorganisms that may lead to microbially influenced corrosion. Other likely sources of water in the gap are from moist air from the reactor building entering through the drain lines and other penetrations in the secondary shield, which are open during operation. The warm moist air will rise through the gap and later cool and condense as water.[4] Moisture may also be trapped in the fill material if it is exposed to a harsh exterior environment during construction.

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a. S. K. Smith, personal communication, Multiple Dynamics Corporation, October 1988.

b. P. Stancavage, personal communication, G. E. Nuclear Energy, October 24, 1988.

BWR Mark III containments have avoided many of the problems of the small gap by providing a larger annular space that does not contain fill material. This permits inspection and recoating activities without severe access problems.

Operational Stressors. The cyclic loads imposed on containment during operation and testing are termed operational stressors. The startup and shutdown of the reactor introduces some cyclic thermal stresses in the metal shell and, especially, in the regions near the penetrations of the high-energy pipe lines. The equipment and piping supports impose vibrational loads on the containment and basemat. The overhead cranes also impose some cyclic mechanical stresses on Mark III containments.

Safety relief valve discharge tests are typically performed once per operating cycle to ensure that the valves are operable.[21] Steam is discharged into the safety relief discharge line at a high flow rate during these tests, causing an increase in pressure, which imposes significant loads on the metal components in the suppression pool.

Appendix J of 10 CFR 50 specifies containment leakage rate test requirements.[13] These tests are designed to detect overall integrated leakage rates and local leakage rates. Overall integrated leakage means leakage through all the potential leakage paths, including the containment welds, valves and fittings, and the containment penetrations. Local leakage means leakage across each pressure-containing or leak-limiting penetration, such as piping penetrations fitted with expansion bellows, air-lock door seals, and electrical penetrations. Preoperational and periodic pressure tests at or above the peak containment internal pressure as specified in the plant technical specifications are required. The peak pressure is related to the design-basis accident pressure. A periodic test schedule is specified in Appendix J of 10 CFR 50, and it includes a set of three overall integrated leakage tests during each 10-year service interval. The frequency of future tests may be increased if the measured overall integrated leakage rate fails to meet the acceptance criteria. These pressure tests induce stresses in the containment vessel that reduce its fatigue life.

9.2.2 Concrete Containments

Internal Environment. The internal environment for concrete containments is similar to the environments in the respective metal containments discussed in the preceding section. The environment affects both steel and concrete components, but somewhat differently. Concrete containments also are subjected to nuclear heating, which produces a slight increase in the concrete temperature and causes some evaporation of the free water in the concrete. This results in a small loss of the shielding properties of the concrete. The effect of radiation on the steel components, that is, liner, reinforcing bars, and tendons, is not significant. The steel liner above the water and the steel dry well head may suffer from corrosion caused by the hot, moist atmosphere inside the containment, and the submerged portion of the steel liner is also susceptible to corrosion if the protective coating is damaged.[22] The atmosphere inside the leak chase channels described in Section 9.1.2 may contribute to corrosion if the humidity level is high.

External Environment. As discussed in Section 9.1.2, the BWR Mark I and Mark II concrete containments are completely enclosed by reactor buildings that are maintained at a pressure slightly below atmospheric pressure. The humidity is relatively low, and the temperatures are mild in these buildings. The only BWR containment exposed to adverse weather is the Mark III concrete containment at the Grand Gulf 1 plant, which is subject to the same stressors as most PWR containments, including wetting and drying cycles, freezing and thawing cycles, and acid rain. Exposure to these adverse external environments can cause cracking and spalling in concrete and may cause corrosion of the reinforcing bars. The degree of deterioration caused by each of these stressors varies, depending on the intensity of each and on the quality of the concrete.

Chemical Reactions in Concrete. In contrast to the metal containments, the concrete in the concrete containments could experience adverse internal chemical reactions, that is, alkali-aggregate reactions, carbonate-aggregate reactions, and cement-aggregate reactions. The alkali-aggregate reactions form expansive products that can cause the concrete to crack and spall. The carbonate-aggregate reactions can lead to corrosion of the reinforcing bars. The reactions between cement and high-silica-content aggregate materials can produce an irregular crack pattern in the concrete referred to as map cracking.

Operational Stressors. The operational stressors for concrete containments are the same as those for the metal containments.

9.3 Degradation Sites

The major degradation sites in BWR containments are those experiencing degradation caused by corrosion and fatigue. Section 9.3.1 identifies these sites in the metal containments; Section 9.3.2 identifies the degradation sites in the reinforced concrete and prestressed concrete containments.

9.3.1 Metal Containments. The carbon steel interior surfaces near the waterline in the Mark I and II suppression pools, and elsewhere, are susceptible to corrosion when they are uncoated or when the coating has deteriorated. The emergency core cooling system suction intake, which is located at the bottom of the suppression pool, is also susceptible to corrosion from the oxygenated water. The embedded portion of the Mark I and II drywells are uncoated and subject to corrosion if there is a gap at the metal–concrete interface where moisture can enter. Differential thermal expansion during startup and shutdown may produce this gap by causing separation of the concrete and drywell near the embedment.

The stainless steel bellows welded to the carbon steel piping located in the high–energy piping penetrations and the Mark I vent lines are susceptible to galvanic corrosion. The bellows are cold–rolled from seamless tubing, which introduces substantial cold work and residual stresses, and may lead to transgranular stress corrosion cracking. In addition, the heat-affected zones near welds in the bellows are sensitized during welding and, therefore, are also susceptible to intergranular stress corrosion cracking.

The exterior surfaces of the Mark I and II drywells are susceptible to corrosion caused by the external environment. The susceptibility increases if there is any uncoated surface or if the compressible fill material is not removed from the gap. The exterior surface near the sand pocket in the Mark I design is also susceptible to corrosion if the gap is not sealed. The exterior surface of the Mark III containment is less likely to corrode because it is accessible to recoat if needed, and no compressible fill material was used.

The drywell, suppression pool, vent lines, and bellows are subjected to fatigue loadings during heat-up, cooldown, and pressure tests. The geometrical discontinuities on the metal containment act as stress risers and are the most likely sites for fatigue damage. Such regions of discontinuity include the portion of the drywell near the embedment, the reinforcing insert plates at the high–energy pipeline penetrations, other penetrations, the transition region from the cylindrical to the spherical portion of the drywell, and the hatches. Misalignment, if present, will further reduce the fatigue life of the bellows. The containment and basemat also experience fatigue damage because of oscillating loads at the piping and equipment supports. The vent header and downcomers in the Mark I torus experience fatigue damage during safety relief valve discharge tests. The lubrite baseplates of the Mark I suppression chamber support columns may wear out and restrict free expansion of the torus. The transition region from the cylindrical to the spherical portion of the Mark I drywell is nearest to the core and, therefore, it is likely to experience irradiation embrittlement damage first.

9.3.2 Concrete Containments. The BWR reinforced concrete containment rebar (reinforcing steel) and metal liners are potential degradation sites. The containment and basemat are subject to fatigue damage caused by the pressure and temperature changes associated with plant heatups and cooldowns and, especially, containment leak rate testing. The geometrical discontinuities introduced by the reinforcing plates on the metal liner near the penetrations act as stress risers and, therefore, the liner and the reinforced concrete at these locations are particularly susceptible to damage during pressure testing. (High–stress concentrations near the reinforcing plates were observed in a containment failure test performed at Sandia National Laboratory in which a metal liner ruptured near a reinforcing plate.[a]) Repeated pressure testing also will introduce local strain or ratcheting of the rebar at the concrete cracks. The reinforcing steel at those sites could then be subject to corrosion if moisture is present in the reactor building. The concrete in the containment walls may experience some cracking and spalling because of moisture and internal chemical reactions. The concrete in the basemat can deteriorate if it is in contact with sulfate–bearing ground water or experiences internal chemical reactions.

The tendons, grease, and anchors in the posttensioning system of the prestressed concrete containment and basemat are potential degradation sites. Failure of tendon anchors and excessive stress relaxation or creep of the tendons will result in a loss of the prestressing force. Deterioration of the grease by microbes may result in severe corrosion of the areas of tendons no longer protected.[23] The metal liner is susceptible to corrosion because of the internal environment; however, because the concrete in the walls is under compression it is less susceptible to cracking or operational stressors, and the reinforcing bars in the concrete wall are less susceptible to corrosion. The basemat in the prestressed concrete containment is likely to

a. W. A. von Risemann, personal communication, Sandia National Laboratory, November 1987.

experience fatigue damage because of oscillating loads at the piping and equipment supports and cracking from possible ground water attack.

9.4 Degradation Mechanisms

The major degradation mechanisms acting on the metal containments are corrosion and fatigue. Other mechanisms are mechanical wear, stress corrosion cracking, and neutron-irradiation embrittlement. These degradation mechanisms are described in Section 9.4.1. The degradation mechanisms acting on the prestressed and reinforced concrete containments include corrosion of tendons, hydrogen embrittlement of anchors, environmental degradation of concrete, corrosion of reinforcing bars and liner, and nuclear heating of concrete. These degradation mechanisms acting on PWR concrete containments are discussed in detail in Volume 1 of this report[24] and are summarized in Section 9.4.2 as applicable to BWR concrete containments.

9.4.1 Metal Containments. BWR metal containments are constructed of carbon steel, and, because of the containment and reactor building environments, the potential for corrosion is high. This is particularly true if the metal surface is uncoated or the coating has deteriorated. The different types of corrosion mechanisms active in metal containments include uniform attack, galvanic corrosion, pitting and crevice corrosion, differential aeration, and microbially influenced corrosion. The type of corrosion mechanism active at any location, and its rate, depend on the environmental conditions, containment design, and materials.

Uniform attack is characterized by the general corrosion of an entire exposed or deteriorated surface and, as a result, the metal becomes thinner.[25] The uniform attack that occurs when metal is exposed to oxygen at containment temperatures forms an oxide film. The corrosion rate then becomes slower as this film thickens because the oxide film acts as a barrier to oxygen diffusion. An appropriate coating on the exposed surface or cathodic protection will provide protection against uniform attack. While preparing the surface for a new coating, care should be taken to minimize the removal of the base metal. Since the external surfaces of the Mark I and II drywells are not easily accessible, it will be difficult to detect coating deterioration on their exterior surfaces and protect them once their coatings have deteriorated. However, the areas of the exterior surfaces near the penetrations can be inspected with the aid of a borescope or a similar device. A borescopic examination performed at the Monticello BWR plant revealed that 50 to 70% of the coating on the drywell exterior surfaces surrounding the penetrations was deteriorated and the exposed metal surfaces were slightly oxidized.[26]

The inside surface of the torus shell at Nine Mile Point 1 (which was designed and constructed as uncoated) has experienced uniform corrosion to a thickness at or below the minimum specified thickness [11.94-mm (0.47 in.)] in some areas. In addition, the plant has also experienced local corrosion or pitting on the inside surface of the torus. The overall corrosion rate of the inside surface of the torus wall was more than double the expected (design) rate of 1.6 mils/year.[27] New York Power Authority's Fitzpatrick plant has also experienced varying degrees of localized corrosion (3 to 9 mils) resulting from degradation of the coatings on the inside wall of the torus.

Dilute sulphuric and hydrochloric acids attack carbon steel very rapidly.[25] If oxidizing conditions or aeration are present, even a very dilute hydrochloric acid solution would cause a destructive attack on carbon steel. Dilute non-oxidizing acids may be present in wet, degraded fill material. Chlorides, likely from the wet fill material (firebar D, which contains magnesium oxychloride), have been found in the Oyster Creek sand pockets.[28]

Ultrasonic testing methods are used to measure and trend wall thinning caused by corrosion. Damage from uniform attack can be easily predicted and allowed for in the original design. The damage from other types of corrosion mechanisms is usually localized and considerably more difficult to predict.

Galvanic corrosion occurs between dissimilar metals, that is, between two metals characterized by differing corrosion potentials, when they are immersed and electrically connected in a corrosive environment. Therefore, the effect of a dissimilar metal joint is to accelerate the corrosion of the less corrosion-resistant metal and to reduce the attack on the more corrosion-resistant metal. Corrosion from galvanic effects is greatest near the dissimilar metal joints, and decreases with increasing distance from the joints.[25] The carbon steel near the dissimilar metal welds between the stainless steel bellows and the carbon steel pipes in the vent and penetration lines are potential sites for galvanic corrosion because the stainless steel is more corrosion-resistant than the carbon steel. In Mark III metal containments, the submerged portion of the containment wall is clad with stainless steel. The area on the unclad wall surface near the stainless steel clad is susceptible to galvanic corrosion if the coating has deteriorated.

A zinc-rich coating on the metal surface provides protection against galvanic corrosion because zinc is usually anodic to both carbon steel and stainless steel and preferentially corrodes and protects the steel. However, a red-lead coating is not likely to provide much corrosion protection because lead is cathodic to steel in dilute, acidic water conditions. Therefore, to ensure continuous protection, the red-lead coating on the metal surfaces should be periodically inspected and if deteriorated, the corresponding surfaces should be recoated with a zinc-rich coating.

Pitting and crevice corrosion are forms of local corrosion that occur on metal surfaces exposed to stagnant or slow moving liquids. Local corrosion represents a selective attack on a metal surface at small areas in contact with an environment. A small surface area experiencing local corrosion contains a local cell, that is, both anodic and cathodic sites at separate nearby locations, and the anodic site experiences corrosion. Local cells are produced because of differences among small nearby areas, which include metal composition differences, different surface film thickness, and environment differences (for example, differences in temperature). The main cause of local corrosion is a migration of cathodic reactants to anodic sites on the metal surfaces. Pitting occurs on metal surfaces that are covered with a thin protective surface film. Metals such as carbon steel, which depend on an oxide film for corrosion protection, are particularly susceptible to pitting at weak spots in the surface film. Some coating systems, epoxy coatings for example, are permeable to water, which becomes trapped between the liner and the coating, causing blisters in the coating. The sites of local failure in the coating are susceptible to pitting. Stagnant water locations, for example, low points in vent headers and penetration sleeves are susceptible to pitting. Crevice corrosion is initiated because of the slow replenishment of oxygen and is accelerated by migration of cathodic reactants in the recesses of a crevice. Crevices that are wide enough to allow moisture or liquid entry but sufficiently narrow to establish a stagnant zone, are potential sites for this type of corrosion. For example, if a crack or gap is present at the interface of the concrete and the metal shell near the embedment, moisture may get trapped and damage from crevice corrosion is likely to occur. The application and maintenance of a proper sealant at the interface can prevent moisture entry into the gap and thus provide protection against crevice corrosion. Other potential sites include cracks or crevices formed between mating surfaces of metal assemblies, for example, loose fitting gasket surfaces and surfaces under bolt and rivet heads. Gasket surfaces can be protected by coating them with a lubricant. the most important potential crevice corrosion site in most Mark I and Mark II containments is probably the gap between the drywell wall and the concrete shield wall. A compressible fill material present in the gap between the drywell and concrete shield wall will probably trap moisture against the metal drywell wall and cause crevice corrosion.[14] Since the drywell outside surfaces are not accessible for recoating or inspection, wall thickness at selected locations should be measured at regular intervals.

Local corrosion caused by *differential aeration* is caused by a gradient in the amount of dissolved oxygen near a water line.[29] The metal walls of the Mark I and II suppression pools are partially submerged in water. The content of dissolved oxygen in the pool water nearest the water line is more plentiful than it is at greater depths. This condition forms a local cell, and the metal surface nearest the water line becomes a cathodic area, while the metal surface lower down becomes an anodic area and experiences localized corrosion. The best protection is to maintain the coating in good condition on the submerged metal surface of the suppression pool. The submerged metal surfaces in Mark III containments are clad with stainless steel and, therefore, are not susceptible to this type of corrosion.

Microbially influenced corrosion (MIC) is the deterioration of a metal by a corrosion process occurring directly or indirectly as a result of the metabolic activities of microorganisms. The products of metabolic activities may reduce the metal surface film resistance or create a corrosive environment.[30] Microorganisms also may directly influence the rate of anodic or cathodic reaction. Deposits on the metal surface resulting from growth and multiplication of microorganisms also may contribute to corrosion. Certain inorganic and organic chemical compounds must be present to supply nutrients, such as oxygen, nitrogen, hydrogen, and sulfur, which are needed for development and growth of the microorganisms. There are two sites on the BWR metal containments that may provide the necessary environment to support microorganisms: the water in the suppression pools and the sand pockets near the base of the Mark I drywells. Aerobic microbes have been found at the beginning of the fuel cycle when there is enough dissolved oxygen in the normally stagnant coolant in the Mark I pressure suppression chamber; and anaerobic microbes have been found at the end of the fuel cycle when most of the oxygen present in the coolant has been consumed.[a] MIC of the torus inside surface can be prevented by the use of a good surface coating.

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a. J. Wolfram, personal communication, EG&G Idaho, December 1987.

Both aerobic and anaerobic microbes have been found in the sand pockets near the Mark I drywell exterior surface. Anaerobic microbes have been found in the wet sand, and aerobic microbes have been found in the dry sand.[a] As discussed above, the sand pockets in Mark I's with an unsealed gap between the drywell and shield wall may contain a large amount of moisture resulting from water leakage during refueling. MIC appears to have contributed to the corrosion of the Oyster Creek drywell in the earlier stages of the process; however, an analysis of the corrosion samples shows that MIC was not the primary cause of the corrosion in the areas where wall thinning was greatest.[31] It is difficult to maintain the coatings on the outside surfaces of the Mark I and II drywells, but cathodic protection should provide adequate protection.[a]

Fatigue. Low-cycle thermal and mechanical fatigue are the major fatigue mechanisms active in BWR metal containments. In low-cycle fatigue, cyclic stresses with magnitudes close to the materials' yield stress cause plastic deformation during each cycle and contribute to fatigue crack initiation and growth.

Heatup, cooldown, and pressure testing introduce high stresses at several sites in BWR metal containments. These include sites with geometric discontinuities that act as stress risers, and sites with adjacent materials with different thermal expansion coefficients. Two examples of drywell sites with significant geometric discontinuities are the reinforcing plates near penetrations and the region connecting the cylindrical and spherical portions of the drywell. The embedded portion of the drywell base represents a site where adjacent materials, that is, concrete and metal, have different thermal expansion coefficients, which may lead to separation at the concrete–metal interface caused by cyclic stresses. Safety relief valve discharge, which occurs through the vent lines into the suppression pool, is the major source of fatigue in the torus and the vent system components. Each discharge causes stresses in the torus shell and the vent header/downcomer intersection. The torus and drywell also experience different thermal and mechanical expansions, which impose fatigue loadings on the vent lines and bellows. Eccentricity, if present, may cause severe fatigue damage to the bellows, and periodic monitoring of their alignment is recommended.[26]

The BWR environments may reduce the fatigue life of the containment. Uncoated surfaces are likely to have shorter periods for crack initiation because of rust pitting and shorter periods for crack growth because of corrosion fatigue.[32] The susceptibility of the Mark III internal metal surfaces to corrosion fatigue is likely to be somewhat higher than for the Mark I and II inside surfaces, because the Mark III environment is not inerted and consists of air. However, the susceptibility of Mark I and Mark II external metal surfaces to corrosion fatigue is likely to be relatively high because of potentially deteriorated coatings and degradation of the fill material. Additional data are needed to determine the impact of corrosion fatigue on the residual life of metal containments.

Stress Corrosion Cracking. The stainless steel bellows are susceptible to intergranular and transgranular stress corrosion cracking. High residual stresses and the BWR containment environment make the sensitized heat-affected zones in the bellows susceptible to intergranular stress corrosion cracking. Intergranular stress corrosion cracking is discussed in more detail in Chapter 12. The large amount of cold work present in the bellows makes even unsensitized portions susceptible to transgranular stress corrosion cracking.[33,a] However, stress corrosion cracking in the stainless steel bellows has never been observed.

Wear and Erosion. Wear can cause undesired changes in dimensions by gradually rubbing away material from contacting surfaces that are in sliding motion. Material may be removed by local shearing, tearing, welding, or some other mechanism. The contact surfaces between the Mark I torus and lubrite baseplates on the support columns (see Figure 9.4) experience relative motion during heatup, cooldown, and pressure testing. Wear may damage these surfaces and restrict their relative sliding motion. Replacement of the lubrite baseplates at some appropriate time may be a solution to this problem.

Erosion caused by the relative motion between the steam and the metal surface removes metal from the surface. The synergistic effects of erosion, wear, and corrosion can also cause undesired dimensional changes, as described above. Steam impingement during safety relief valve or other discharges may cause erosion of the vent system exposed torus inside surfaces.[26]

Irradiation Embrittlement. BWR metal containments are exposed to modest neutron fluence levels at temperatures of 54 to 66°C (130 to 150°F). This exposure may increase the nil-ductility transition temperature of the carbon steel base materials and welds used in their designs. The original nil-ductility transition temperature for these materials, that is, the

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a. S. K. Smith, personal communication, Multiple Dynamics Corporation, November 1987.

SA-516 Grade 70 and SA-212 Grade B carbon steels, is about −12°C (10°F).[34,35] Similar data for the weldments in the metal shell are not available. At the end of the forty-year license period, the neutron fluence at a typical Mark I drywell is estimated to be about 10^{14} n/cm^2 (>1 MeV).[a] Very little research has been done to determine the increase in the nil-ductility transition temperature, if any, for carbon steel and welds subjected to this low-temperature low-fluence irradiation. Most of the available data are for higher fluence at temperatures higher than 232°C (450°F).

However, the radiation damage data from the surveillance program for the high-flux isotope reactor (HFIR) at the Oak Ridge National Laboratory can probably be used to estimate the increase in the BWR containment nil-ductility transition temperatures.[35] The HFIR facility operates at a temperature of 49 to 75°C (120 to 167°F), and its reactor pressure vessel shell is made of SA-212, Grade B carbon steel. The HFIR data show an estimated shift of 11°C (20°F) in the nil-ductility transition temperature at a fluence of 2×10^{16} n/cm^2. Based on these data, the shift in the nil-ductility transition temperature of a Mark I metal containment at a fluence of 10^{14} n/cm^2 will be negligible.[35] Note also that the HFIR flux is about 2×10^8 n/cm^2/s, compared to a typical flux level of about 1×10^5 n/cm^2/s in a BWR containment wall. At these flux and fluence levels, a typical BWR containment wall will not reach the levels of the shift in nil-ductility transition temperature observed at HFIR during any period considered for plant life extension.

9.4.2 Concrete Containments. The degradation mechanisms for BWR reinforced and prestressed concrete containments are similar to those of the corresponding PWR containments discussed in Volume 1 of this report.[24] However, there is one major difference in the design of PWR and BWR concrete containments. Although all the PWR primary containments are exposed to the natural external environment, including wetting and drying and freezing and thawing cycles, only one out of the eleven BWR primary concrete containments is exposed to such an environment. That one is the Mark III reinforced concrete containment at the Grand Gulf plant. All nine BWR Mark I and Mark II concrete containments and the Mark III concrete containment at the Clinton plant are completely enclosed by a reactor building and protected from the degrading effects of the harsh external environment. The BWR containment internal environment is more humid than that of the PWR containment, but the Mark I and Mark II containments have low oxygen levels in the air above the pressure-suppression pools.

Internal concrete reactions, that is, alkali-aggregate, cement-aggregate, and carbonate-aggregate reactions, can produce concrete cracking. Also, sulfate-bearing ground water can cause internal concrete reactions and subsequent concrete cracking. Cracks in the concrete are likely to provide a corrosive external environment with access to the mild steel reinforcing bars. The Mark III containment at Grand Gulf may be the most susceptible because it is exposed to frequent wetting and drying cycles, which may dissolve (leach) the calcium hydroxide. Extensive leaching will cause an increase in concrete porosity and lead to reduced strength and increased vulnerability to other corrosive environments.

The BWR containments and basemats are subject to fatigue damage caused by the pressure and temperature changes associated with plant heatups and cooldowns and, especially, the containment leak-rate testing. The high pressures associated with the periodic testing of the containment leak rate open existing cracks in the concrete, and these cracks may introduce localized strain in the rebar and, possibly, in the steel liner. The high test pressure can also introduce high stresses in the liner near geometric discontinuities introduced by the reinforcing plates near the penetrations. Repeated pressure testing can cause fatigue damage to rebar and liner, and may leave some of the cracks in the concrete open after completion of the tests. If these open cracks expose the rebars to the reactor building environment, rebars may corrode. The 10 CFR 50, Appendix J, leakage rate testing requirements for test frequency and pressure should be evaluated in light of the potential fatigue damage that may occur as a result of these tests.

If the reinforcing bars are used as ground connections for electrical equipment, the direct electric current, that is, stray currents, passing through the bars may cause rapid corrosion of the reinforcing steel. Some examples of corrosion of buried metal components by stray currents are discussed in Reference 29.

The interior surfaces of the concrete containment structures and the top surfaces of the basemat structures are generally covered with a continuous steel plate so as to create a leak tight vessel. The steel liner serves no structural function, and the concrete containment wall is designed to withstand design loads without the liner. Many similarities exist between the liner

a. S. K. Smith, personal communication, Multiple Dynamics Corporation, November 1987.

plate in the concrete containments and the metal containments discussed earlier. As was described, several types of corrosion can occur in this plate: general surface corrosion, crevice or pitting corrosion, differential aeration, galvanic corrosion, and microbially influenced corrosion. A good protective coating (phenolic or zinc–rich) can protect the liners. Because the liner is comparatively thin, usually between 6.4 mm (0.25 in.) and 13 mm (0.5 in.), there is very little allowance for material loss from corrosion. However, corrosion of the interior surfaces of the liner plate of concrete containments should not be widespread unless a failure of the protective coating occurs and repair or maintenance is not performed over a lengthy duration.

The major degradation mechanisms associated with the prestressed concrete containment posttensioning systems are creep and relaxation of the tendons, microbially influenced corrosion of the tendons, and hydrogen embrittlement of the anchors.[36] Tendon relaxation and creep may cause loss of the prestressing force. Microorganisms can also degrade the tendon grease and make the tendons more susceptible to corrosion.[23]

One of the main functions of concrete in the containment is to provide shielding. Radiation causes some nuclear heating in the concrete and may cause some evaporation of the free water in the concrete and, thus, somewhat degrade its shielding properties.

9.5 Potential Failure Modes

The primary containment of a BWR plant represents the final barrier to the release of radioactivity during normal operation, abnormal transients, or accidents. Therefore, any degradation of the containment pressure boundary is likely to contribute to the potential failure of this function. Section 9.5.1 describes potential failure modes for metal containments and presents relevant field data. Section 9.5.2 briefly describes the potential failure modes for concrete containments. See Volume 1 of this report (Reference 24) for additional information on concrete containments.

9.5.1 Metal Containments. Time–dependent degradation of a BWR metal containment may result in violation of the integrity of the containment, which could permit leakage during normal operation, and leakage from or even rupture of the containment during a severe abnormal transient or an accident. Corrosion is the major degradation mechanism that causes general or localized thinning of the containment wall. Uniform attack causes general thinning but it is not likely to lead to a failure because the attack becomes slower as the corrosion film thickens. Other types of corrosion mechanisms that cause localized damage at significantly higher rates are more likely to lead to a failure of the containment pressure boundary. It is likely that any localized damage will be detected early enough and adequate mitigating actions taken when the metal surfaces are accessible. The metal surfaces that are not easily accessible for inspection are of major concern because the damage may remain undetected and potentially lead to failure when the containment is loaded during an accident. These surfaces include the external surfaces of the drywell in the Mark I and Mark II containments, the embedded portion of the drywell base, the submerged metal surfaces in the suppression pools of the Mark I and Mark II containments, and the inside surface of the expansion bellows in all the containment types.

The design and operation of the Oyster Creek plant resulted in localized drywell corrosion caused by moisture trapped in the sand pockets for a considerable period of time. The bellows had been leaking several years,[4] fill materials (that is, firebar D and fiberglass) were left in the gap between the drywell and the secondary concrete shield, and the gap was not sealed.[5] In addition, the red–lead coating applied to the outside surface of the Oyster Creek drywell does not provide adequate corrosion protection to carbon steel subjected to dilute acidic water conditions. The lead in the red–lead coating is cathodic to the carbon steel in dilute acidic water conditions, and, therefore, the steel is sacrificial with respect to the lead.[25,37] A detailed evaluation of the Oyster Creek drywell wall indicated that the carbon steel shell was damaged by local corrosion influenced by oxygen depletion, moisture, temperature, and chloride contamination. The average corrosion rate over the past 20 years is believed to be 17 to 20 mills per year.[28] The resulting corrosion has reduced the drywell thickness by as much as 10.4 mm (0.41 in.) from the as–fabricated thickness of 29.31 mm (1.154 in.).[38] Such wall thinning, if unchecked, could potentially lead to a small crack and leakage during normal operation, or a large rupture and significant leakage during an accident.

Local corrosion and pitting as deep as 2.3 mm (0.09 in.) has been found during an inservice inspection of the inside surface of the torus at the Nine Mile Point 1 and Fitzpatrick plants.[39] The torus at the Nine Mile Point 1 plant is below the minimum wall thickness [11.4 mm (0.447 in.) at the bottom of the torus] at several locations.[40] Measurements indicate that the corrosion rate may be as high as 0.084 mm/year (0.0033 in./year) which is more than double the rate of 0.041 mm/year (0.0016 in./year) assumed in the original design. Niagara Mohawk Power Corporation plans to apply a protective coating to the inside surface of the torus in 1990 to mitigate further corrosion.

The Mark I and Mark II metal containment drywells are free-standing shells supported at the base by a concrete embedment. Corrosion of the metal shell embedded in the concrete may potentially lead to a loss of support for the drywell. A 50-mm (2-in.) corrosion band (0.8 mm loss in wall thickness) was discovered just below of the concrete-drywell seal on the Monticello BWR containment. This corrosion was caused by deterioration of the internal concrete-drywell seal, which allowed moisture to contact the embedded drywell shell.[3] This wall thinning is still within the corrosion allowance. The embedded metal surface is not easily accessible for inspection or recoating. One means of mitigating this problem is to install and maintain a seal to protect the exposed metal surface from the containment internal environment. Experience with sealants has shown a useful life cycle from 2 to 10 years, depending on the type, application, and environment. Consequently, short maintenance intervals are required to ensure integrity of the seal.[a]

The stainless steel bellows in the vent pipes and high-energy penetration pipe lines also constitute part of the containment pressure boundary. As discussed above, the bellows may be subject to intergranular and transgranular stress corrosion cracking (IGSCC and TGSCC) and fatigue damage. IGSCC can occur in the heat-affected zones, and TGSCC can occur in the unsensitized portions of the bellows. The vents, vent headers, and downcomers are also susceptible to corrosion if uncoated or if the coating has deteriorated. The potential failure mode is cracking and deterioration to the extent that leakage occurs.

9.5.2 Concrete Containments. Corrosion of the reinforcing steel will challenge the structural integrity of both reinforced and prestressed concrete containments. This corrosion normally occurs because of poor quality concrete or concrete deterioration that has led to cracks permitting the ingress of aggressive environments. Therefore, the reinforcing steel in Mark III concrete containments, if exposed to adverse weather, is especially susceptible to corrosion. Corrosion of the metal liner could potentially lead to leakage of radioactive gases through the liner and through cracks in the concrete to the reactor building.

The potential failure mode for the posttensioning system in the prestressed concrete containments is the loss of prestress in the tendons. The factors that may contribute to the loss of prestress are relaxation and creep of the tendon wires, corrosion of the tendon wires, breakdown of the corrosion protecting grease, and failure of the anchors by corrosion and hydrogen embrittlement. When prestress losses exceed those allowed in the original design, then the high pressures resulting from some accidents may tear off the steel liner and cause sizable cracks in the concrete, though overall structural stability of the containment would still be maintained.

The potential failure mode for the concrete containment during an accident is leakage of radioactive fluids. The high pressures during an accident are likely to cause cracking in the metal liner near reinforcing plates, which act as stress risers. During normal operation, these sites experience fatigue damage, which will contribute to any potential failure during an accident.

9.6 Inservice Inspection and Surveillance Methods

The inservice inspection requirements are outlined in Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, of the *ASME Boiler and Pressure Vessel Code*. ASME Section XI, Subsection IWE, contains the rules and requirements for metal containments, and Subsection IWL contains the rules and requirements for concrete containments. The main objective of these subsections is to ensure that the integrity of the containment pressure boundary is maintained throughout a plant's lifetime. The provisions of these subsections are being reviewed by the USNRC, and federal regulations that will require mandatory compliance by nuclear plant owners are forthcoming.[41] Currently, concrete containment inspections and testing are performed in accordance with the guidelines of Regulatory Guides 1.35, 1.90, and 1.136.[42,43,44] The pressure test requirements are outlined in Appendix J of 10 CFR 50.[13] Section 9.6.1 describes the inservice inspection requirements for metal containments, and Section 9.6.2 describes the inservice inspection requirements for concrete containments.

9.6.1 Metal Containments. Subsection IWE on preservice examination requires that 100% of the pressure-retaining welds, dissimilar metal welds, and pressure-retaining components and vessel walls be visually examined and pressure tested.[45,46] Subsection IWE inservice examination requires visual examination of 50% of each dissimilar metal weld and 25% of each of the other welds during the inspection

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a. S. K. Smith, personal communication, Multiple Dynamics Corporation, November 1987.

intervals. The portions of welds examined are to be randomly selected and to represent that type of welded joint. In addition, a visual examination of the containment vessel pressure retaining boundary is required prior to each 10 CFR 50 Appendix J, Type A leakage rate test.[45]

If the containment vessel is painted or coated for corrosion protection, the visual examinations can be performed without removing the coating. If the examination identifies evidence of flaking, blistering, peeling, discoloration, or other signs of distress in the coated surface, these sites need to be cleaned by removal of the coating to the base metal for surface or volumetric examinations. Indications from visual or surface examination of components that exceed the ASME Acceptance Standards may require repair or replacement to meet the standards. The exposed sites, if damaged, must then be repaired or replaced and recoated.

EPRI has assessed the reliability of magnetic particle inspection of welds through protective coatings and has found that this technique can detect flaws through 0.4 mm (0.016 in.) of coating.[47] This method has been used successfully in the offshore oil and gas industry for nearly 50 years. The magnetic particle inspection technique should be field tested at nuclear plants and then included in the ASME Boiler and Pressure Vessel Code Section XI on inservice inspection.

Some plants examine only the portion of the suppression chamber above the water line. To examine the submerged surfaces, the suppression chamber must be drained or underwater examination techniques must be employed. Draining of the suppression chamber results in a large pressure reduction that may cause additional blistering or popping of existing blisters in the coating. Underwater techniques have been developed to include desludging, ultrasonic mapping of critical areas, coating adhesion tests, measurement of dry film thickness, and spot repairs of degraded areas.[48,49]

The external surfaces of the Mark I and Mark II drywells, which are susceptible to corrosion damage as discussed in Section 9.4, are exempted from preservice and inservice examinations because they are inaccessible.[45] Since corrosion damage can cause significant thinning of the containment wall, the thickness at selected locations should be measured periodically. This has been done using standard ultrasonic methods.[38] However, standard ultrasonic methods cannot reliably detect thinning of the Mark I drywell wall adjacent to sand pockets because the outer surface of the wall is in contact with sand, gravel, and, possibly, groundwater. In addition, the inner surface of the wall adjacent to the sand pocket is covered by a concrete floor and is not accessible to the standard through-wall, pulse-echo type ultrasonic method. An electromagnetic acoustic transducer (EMAT) is being developed to detect corrosion damage to the drywell wall adjacent to the sand pocket,[50] and may be used to detect corrosion damage in the embedded portion of the drywell.

Repair, modification, or replacement of the pressure-retaining boundary of the containment requires pneumatic leakage tests, as described in Appendix J of 10 CFR 50.[13] These include integrated leakage rate tests (Type A) and local leakage rate tests (Types B and C) and are performed at the calculated peak containment internal pressure related to the most severe design-basis accident specified in the Technical Specifications. The integrated leakage rate tests are to be performed after the containment has been completed and is ready for operation, and at periodic intervals thereafter to ensure leak tightness. The local leakage rate tests are intended to detect and measure local leakage across each pressure-retaining containment penetration. Typically, two-ply expansion bellows are used in the containment penetrations and represent a double barrier to local leakage. It is recommended that local leakage rate tests be performed to detect leakage across each ply of each bellows. The bellows may be tested by pressurizing between plys such that the inner and outer ply are tested simultaneously. This practice is followed at several BWR plants.

9.6.2 Concrete Containments. The ASME requirements for metal containments described in Section 9.6.1 also apply to the steel liners of concrete containments.[45,46] The ASME requirements for the inspection of concrete surfaces in all concrete containments and ungrouted tendons in prestressed concrete containments are described in ASME Section XI, Subsection IWL.[41,51] These requirements will become mandatory upon regulatory action by the USNRC.[41]

Table 9.10 summarizes the inspection requirements and guidelines for an appropriate inservice inspection and surveillance program for concrete containment surfaces and ungrouted tendons in prestressed concrete containments. These guidelines are from Subsection IWL and Regulatory Guides 1.35 and 1.90.[43,44]

Preservice and inservice examinations require that the concrete surfaces, including coated areas, be visually examined for indication of any condition that may indicate any damage or degradation. If the surface

Table 9.10. Evaluation and acceptance criteria for inservice inspection of concrete containments[41]

Area Examined	Examination Method	Evaluation Criteria	Acceptance Criteria
Concrete surface	Visual	Evidence of conditions indicating damage or degradation	No evidence of damage or degradation sufficient to warrant evaluation or repair
Tendon force	Liftoff or equivalent test	Prestress force	Average measured forces in all tendons equal to or greater than required prestress
			Individual measured force in each tendon not less than 95% of predicted force
Tendon wire or strand	Visual	Corrosion, mechanical damage, and wedge slippage marks	Corrosion within limits set by owner, free of physical damage
	Tension test	Yield strength, ultimate tensile strength, and elongation	Less than minimum specified values
Tendon anchorage areas	Visual	Concrete cracks, corrosion, broken or protruding wires, missing buttonheads, broken strands, cracks in anchorage hardware	Concrete cracks do not exceed 0.01 in. adjacent to bearing plates, no cracks in anchor heads, shims, or bearing plates; corrosion is within the limits set by owner, broken or unseated wires, strands, and buttonheads are previously documented and accepted
	Free water in end cap	Volume measurement	Volume documentation
Corrosion protection medium	Sample analysis	Reserve alkalinity, water content, water soluble chlorides, nitrates, sulfides	Within specified limits
Tendon free water	Alkalinity analysis	pH	Within specified limits

condition is found unacceptable, then further evaluation or repair is required. Portions of the concrete surface covered by the liner or that are otherwise not accessible are exempt from the inspection requirements.

Prestressing tendons are selected randomly from each group of vertical, inverted U, dome, and hoop tendons and inspected for any loss of prestress. A wire is removed from one tendon of each type during each inspection, and is examined over its entire length for corrosion, mechanical damage, and wedge slippage marks. Tension tests are performed to determine yield strength, ultimate tensile strength, and elongation of the wire. The visual examination of tendon anchorage areas includes inspection of bearing plates, anchors, buttonheads, and the surrounding concrete. Samples of free water contained in the anchor end cap, and any that drains from the tendon during the examination, are collected and analyzed to determine pH. Samples of the corrosion protection medium (grease) are required to be analyzed for reserve alkalinity, water content, and concentration of water soluble chlorides, nitrates, and sulfides.[41] If the test and analysis results do not satisfy acceptance criteria, a possible abnormal degradation of the containment pressure boundary is indicated. Such an occurrence must be reported to the USNRC.

9.7 Summary, Conclusions, and Recommendations

A summary of the important aging degradation sites, stressors, and mechanisms; potential failure modes; and current inservice inspection and test requirements for the BWR metal containments is presented in Table 9.11. The ranking of the sites is based on the consequences of the potential failure modes. Among the sites having the same failure modes, a site that is more susceptible to failure is ranked higher. The exterior surfaces of Mark I and Mark II containments are ranked higher because they are not easily accessible for inspection. The conclusions and recommendations for the metal containments are as follows.

1. Corrosion of the drywell shell is the primary safety concern. Crevice corrosion, pitting, uniform corrosion, and microbially influenced corrosion are degradation mechanisms that can attack the outside surface of the drywell. Use of nondestructive inspection methods to measure the thickness of the drywell shell at selected sites is recommended to assess any damage from corrosion. The magnetic particle inspection technique for inspecting welds in the drywell through protective coatings should be field–tested, and included in the ASME Boiler and Pressure Vessel Code Section XI. Mitigation methods, such as cathodic protection, need to be developed to protect the drywell shell from corrosion. In addition, use of zinc–rich or phenolic coatings instead of red lead or epoxy coatings is recommended.

2. The embedded portion of the drywell is subjected to thermal cycles that may lead to separation at the concrete–metal interface and failure of any sealant at the interface. The embedded portion of the drywell shell is generally not coated during construction. Therefore, moisture can enter the gap at the interface and make the embedded portion of the drywell shell susceptible to crevice corrosion. The application and maintenance of a sealant at the interface can prevent moisture entry and, thus, provide protection against corrosion. Electromagnetic acoustic transducers need to be developed and field–tested to detect corrosion of the embedded portion of the drywell shell.

3. The submerged portions of the Mark I and Mark II suppression pool walls are susceptible to corrosion by differential aeration and microbially influenced corrosion. A good quality protective coating (for example, zinc–rich coating) needs to be maintained on the inside surface.

4. The sites of geometric discontinuities are subject to somewhat higher levels of thermal and mechanical fatigue than the overall containment, and the BWR corrosive environment may act synergistically with fatigue. Therefore, corrosion–fatigue data for the shell material in the typical BWR environments are needed.

5. The stainless steel bellows may undergo intergranular stress corrosion cracking in the heat–affected zones, and transgranular stress corrosion cracking in the unsensitized portions of the bellows. The nearby carbon steel pipe may be subject to galvanic corrosion caused by the dissimilar metal welds. The bellows are also subject to fatigue damage during normal operation and leak testing, and if there is any eccentricity, the reduction in fatigue life is likely to be an even more significant factor.

Table 9.11. Summary of degradation processes for BWR metal containments

Rank	Degradation Sites	Stressors	Degradation Mechanisms	Potential Failure Modes	ISI Methods
1	Exterior surfaces of Mark I drywell base near sand pocket	Moisture, microorganisms degraded fill material	Uniform corrosion, crevice corrosion, microbially influenced corrosion	Leakage of radioactive gases	Leakage testing (10 CFR 50 Appendix J)
2	Exterior surfaces of Mark I and Mark II drywell	Degraded fill material, moisture	Crevice corrosion, uniform corrosion, pitting	Leakage of radioactive gases	Leakage testing (10 CFR 50 Appendix J)
3	Embedded shell region	Cyclic thermal loading, corrosive environments	Thermal fatigue, crevice corrosion, pitting	Loss of structural integrity	None
4	High–energy pipe line penetrations, hatches, vent lines	Cyclic thermal loading, pressure testing, corrosive internal environments	Thermal and mechanical fatigue, environmentally assisted fatigue	Leakage of radioactive gases	Visual inspection, leakage testing (10 CFR 50 Appendix J)
5	Stainless steel bellows	Corrosive internal environment, cyclic thermal loading, pressure testing	IGSCC[a] at heat–affected zone, TGSCC,[b] fatigue	Leakage of radioactive gases	Visual inspection, leakage testing (10 CFR 50 Appendix J)
6	Submerged portion of suppression pool	Corrosive internal environment, safety relief valve discharge tests, pressure testing, microorganisms	Differential aeration, mechanical fatigue, pitting, microbially influenced corrosion	Leakage of radioactive gases	Visual inspection, leakage testing (10 CFR 50 Appendix J)
7	Transition region from cylindrical to spherical portion of Mark I drywell, drywell shell at the core horizontal midplane elevation	Cyclic thermal loading, pressure testing, corrosive environments, neutron irradiation	Thermal and mechanical fatigue, environmentally assisted fatigue, irradiation embrittlement	Leakage of radioactive gases	Visual inspection, leakage testing (10 CFR 50 Appendix J)

Table 9.11. (continued)

Rank	Degradation Sites	Stressors	Degradation Mechanisms	Potential Failure Modes	ISI Methods
8	Dissimilar metal welds	Corrosive environments, cyclic thermal loading, pressure testing	Galvanic corrosion, fatigue	Leakage of radioactive gases	Visual inspection, leakage testing (10 CFR 50 Appendix J)

a. Intergranular stress corrosion cracking.

b. Transgranular stress corrosion cracking.

The bellows constitute part of the containment pressure boundary, and their inside surfaces are not easily accessible for surface examination. Therefore, an NDE method to detect cracks in the bellows needs to be developed. In addition, it is prudent to test each ply for leakage during local leak testing of a two-ply bellows, and the alignment (that is, eccentricity) of the bellows should be maintained so as to minimize fatigue damage.

6. The drywell shell near the core midplane elevation may be subject to irradiation embrittlement. However, the data from the surveillance program at the Oak Ridge National Laboratory High-Flux Isotope Reactor (HFIR) suggest that the increase in the nil-ductility transition temperature of the drywell shell material will be negligible over the projected 40-year lifetime of a BWR plant.

There are ten BWR concrete containments in the United States: eight reinforced and two prestressed containments. All the BWR concrete containments except for one of the Mark III containments are completely enclosed in a reactor building that protects them from the degrading effects of the harsh external environment. A summary of the important degradation sites, stressors, degradation mechanisms, potential failure modes, and current inservice inspection and test requirements for the BWR reinforced concrete containments and the prestressed concrete containments is presented in Tables 9.12 and 9.13, respectively. These tables are similar to the corresponding tables for PWR containments presented in Volume 1 of this report.[24] The conclusions and recommendations for the concrete containments also are similar to those for the corresponding PWR containments and are as follows.

1. Corrosion of the reinforcing bars is a major aging concern for the exposed Mark III containment. Internal chemical reactions could introduce cracks in the concrete, which may provide the harsh external environment access to the mild steel reinforcing bars. Reinforcing bars in the other concrete containments are less susceptible to corrosion because the reactor building provides protection from the harsh external environment.

2. Stray currents, if present, can also cause corrosion of the reinforcing bars. Additional information about the long-term degradation of reinforcing bars is needed. Relevant data should be collected from the older LWR containments and from facilities that have been shut down after extended service. Accelerated aging techniques should also be evaluated and, if appropriate, used to obtain additional data.

3. Hydrogen embrittlement of the posttensioning system anchors, pitting of the tendon wires, and microbially influenced loss of corrosion resistance of tendon grease are possible aging concerns for the posttensioning systems. Improved methods of monitoring degradation of anchors and decomposition of tendon grease are needed.

4. A comprehensive inservice inspection program is needed to identify and quantify degradation in reinforced and prestressed concrete containments.

Table 9.12. Summary of degradation processes for BWR reinforced concrete containments

Rank	Degradation Sites	Stressors	Degradation Mechanisms	Potential Failure Modes	ISI Methods
1	Reinforcing bars	Corrosive external environment (Mark III), stray currents	Corrosion, fatigue	Loss of structural integrity	None
2	Mark I and Mark II suppression pool steel liner below water line	Cyclic thermal and mechanical loads, corrosive internal environment, microorganisms	Corrosion caused by differential aeration, microbially influenced corrosion, fatigue	Leakage of radioactive gases	Visual inspection, leakage testing (10 CFR 50 Appendix J)
3	Drywell steel liner, suppression pool steel liner above water line	Moisture, corrosive internal environment, cyclic thermal and pressure loads	Corrosion, fatigue	Leakage of radioactive gases	Visual inspection, leakage testing (10 CFR 50 Appendix J)
4	Concrete	Aggressive external environment, internal chemical reactions, nuclear heat, leakage testing	Cracking, spalling, loss of free water	Degradation of shielding properties	Visual inspection

Table 9.13. Summary of degradation processes for BWR Mark II prestressed concrete containment

Rank	Degradation Sites	Stressors	Degradation Mechanisms	Potential Failure Modes	ISI Methods
1	Posttensioning system anchors	Trapped water, steady–state stress	Hydrogen embrittlement, corrosion	Loss of stress	Tendon surveillance program, visual inspection
2	Posttensioning tendon wire or strand	Moisture, trapped water, microorganisms, steady–state stress	Pitting, microbially influenced corrosion, relaxation	Loss of stress	Tendon surveillance program
3	Suppression pool steel liner below water line	Cyclic thermal and mechanical loads, fatigue, corrosive internal environment, microorganisms	Fatigue, corrosion caused by differential aeration, microbially influenced corrosion	Leakage of radioactive gases	Visual inspection, leakage testing (10 CFR 50 Appendix J)
4	Drywell steel liner, suppression pool steel liner above water line	Moisture, corrosive internal environment, cyclic thermal and pressure loads	Corrosion, fatigue	Leakage of radioactive gases	Visual inspection, leakage testing (10 CFR 50 Appendix J)
5	Reinforcing bars	Stray currents	Corrosion	Loss of structural integrity	None
6	Concrete	Internal chemical reaction, nuclear heat, leakage testing	Cracking, spalling, creep, loss of free water	Degradation of shielding properties, loss of stress in posttensioning tendons	Visual inspection

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10. BOILING WATER REACTOR FEEDWATER AND MAIN STEAM LINE PIPING

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The boiling water reactor (BWR) system used for power generation is a direct-cycle steam generating system that produces steam in a reactor core to drive a turbine. Unlike the pressurized water reactor (PWR), in which the feedwater piping and main steam lines are part of a secondary system with fluid that does not flow through the reactor itself, the coolant in the BWR feedwater piping and main steam lines flows directly into and out of the reactor vessel. Thus, the feedwater piping and main steam lines constitute part of the primary system, and leaks or failures of these lines may cause a severe transient.

The location of any break in the feedwater or main steam piping largely determines the sequence of events that will follow. A break in either a feedwater or a main steam line within the containment (between the reactor pressure vessel and the first main steam isolation valve or the feedwater check valve inside the containment) constitutes a breach of the primary coolant system boundary and presents a challenge to the emergency core cooling system. Breaks in the feedwater or steam piping outside the containment, for example in the vicinity of the main feed pumps, will disrupt the coolant flow and heat transfer from the reactor; however, the isolation valves are expected to prevent drainage of the primary coolant inventory through the break. Therefore, the safety class and construction codes applied to the piping inside and outside containment are different, as shown in Table 10.1.[1,2] The breaks outside containment require activation of the following two emergency core cooling systems: the reactor core isolation cooling and the high-pressure coolant injection systems. Breaks of either the feedwater or the main steam line inside the containment are considered loss-of-coolant accidents (LOCA) and require injection from both the high- and the low-pressure emergency core cooling systems to keep the core covered.[1]

The aging mechanisms that degrade feedwater and main steam system piping in both BWR and PWR plants are similar, but vary because of water chemistry. The feedwater line breaks that have occurred in operating nuclear power plants are attributed to wall thinning caused by an erosion-corrosion mechanism and to fatigue-induced cracking caused by thermal stratification. Vibrations and water hammer events also contribute to feedwater line damage.

The feedwater and main steam piping outside the containment do not undergo as rigorous an inservice inspection program as piping within the containment. Thus, significant degradation may occur over a period of time without being detected. If degraded piping is subsequently subjected to intense mechanical loadings, such as pressure pulses, water hammers, or seismic events, the pipe may rupture catastrophically.

Although pipe failures ranging from partial cracking to complete rupture of the pipe wall have been reported in BWR steam and feedwater systems,[5,6,7] the failures have predominantly occurred in small diameter [<152-mm (<6-in.)] piping, such as the low-flow sample and drain lines. There have been no failures reported of large main steam and feedwater lines within a BWR containment.

Table 10.1. Safety classes and fabrication codes for BWR steam cycle piping[1,2]

Piping	Safety Class	Code
Steam and feedwater piping to outermost containment isolation valves	Safety related, Class 1	ASME Code, Section III, Class 1[3]
Balance of piping up to, but not including, the outermost containment isolation valves	Nonsafety related[a]	ANSI B31.1[4]

a. Even though this piping is classified as nonsafety related, piping thickness and material on both sides of the valve are comparable.

10.1 Description

Figure 10.1 shows a fluid flow diagram for a BWR plant. Steam is produced directly in the coolant circulating through the reactor core. Moisture is removed from the steam by a separator located in the reactor pressure vessel above the core, and the saturated steam produced in the reactor flows through the high- and low-pressure turbines located outside of the containment. The steam from the low-pressure turbine is condensed and the noncondensible gases are removed. The condensate is then returned to the reactor by the feedwater system forming a closed loop. The feedwater system supplies the cooling water to remove heat from the reactor.

The BWR coolant circulates both inside and outside of containment. Figure 10.2 shows the main feedwater system extending from downstream of the low-pressure feedwater heaters to the feedwater spargers in the reactor pressure vessel (RPV). Pressure high enough to force feedwater into the RPV is supplied by two (or three in some designs) feed pumps. The coolant in the feedwater lines is subcooled, and at a pressure of 3.64 and 7.85 MPa (528 and 1138 psi) at the feedwater pump suction and discharge, respectively. The feedwater passes through the set of high-pressure feedwater heaters, which are provided with motor-operated inlet and outlet valves and raise the temperature of the feedwater to about 215°C (420°F). The two branch lines combine into a 762-mm (30-in.) header. The feedwater piping then branches into two 508-mm- (20-in.-) outside diameter (OD) carbon steel lines (see Table 10.2 for material types) that leave the turbine building, pass through the auxiliary building, and penetrate the drywell containment. There are two isolation valves in each line in the auxiliary building. The first is a motor-operated valve that may be closed by the operator for containment isolation. The second is an air-operated positive-acting check valve with spring-assisted seating and free swinging disks to prevent reverse flow. Inside the drywell is a check valve and a manually operated maintenance valve. Finally, each of the two feedwater lines branches into three 305-mm- (12-in.-) lines that connect to the RPV. Chapter 11 describes the feedwater system entry into the reactor pressure vessel. The pipe wall thickness differs with the various diameters of the piping and with the design pressure at the location, which are plant specific. Typically, Schedules 80 and 100 are used such that the wall thicknesses range from about 17.5 to 21.4 mm (0.69 to 0.84 in.) for 305-mm (12-in.) pipe and 26.2 to 32.5 mm (1.03 to 1.28 in.) for 508-mm (20-in.) pipe. During full-power operation of a BWR plant, the feedwater system supplies approximately 4.5 to 6.8 x 10^6 kg/h (10 to 15 x 10^6 lb/h) of water (depending on the size of the plant) to the RPV. The flow velocities in both 305-mm (12-in.) and 508-mm- (20-in.-) piping sections are about 6.6 m/s (21.8 ft/s) at full power.

The steam produced by the reactor is delivered to the turbines by four carbon steel main steam lines (see Table 10.2 for material types) as shown in Figure 10.3. The OD and wall thickness of the main steam lines are in the range of 610 to 710 mm (24 to 28 in.) and 25.4 to 31.8 mm (1.0 to 1.25 in.), respectively. BWR system design temperature and pressure are 302°C (575°F) and 8.62 MPa (1250 psi), respectively. Within the containment, each steam line contains a number of safety relief valves (SRVs) for overpressure protection, a steam-flow restrictor (shown in Figure 10.1) to limit the loss of inventory in the event of a steam line rupture, and an inboard air-operated main steam isolation valve (MSIV). One main steam line provides continuous venting of the reactor vessel head area during operation and supplies steam to the reactor core isolation cooling and residual heat removal (RHR) systems. In the auxiliary building, each main steam line contains a redundant outboard air-operated MSIV and a motor-operated main steam shutoff valve. Figure 10.4 shows how the main steam lines leave the RPV and exit through a Mark 1 containment. The steam generated in the reactor leaves the separator at 287°C (549°F), at 6.65 MPa (965 psi) pressure, and with a moisture content of about 0.1%. The temperature is somewhat lower [284°C (543 °F)] at the second isolation valve, and the moisture content is about 0.2%. The steam velocity (at full power) in the main steam lines is 46 m/s (150 ft/s) and the moisture content upon reaching the high-pressure turbine is about 0.3%.

In the case of a line break or other breach of the coolant system outside of the containment, both the feedwater lines and the main steam lines would provide a direct pathway leading from the RPV to the reactor building and, eventually, to the environment. To provide isolation in such an event, each feedwater line contains three containment isolation valves (one motor-operated valve and two check valves). Isolation of the steam lines is provided by the MSIVs and a main steam block valve located just before the turbine inlet. (Two MSIVs are installed on each of the four main steam lines, as shown in Figure 10.3, and discussed above.) Each of the main steam lines also contains a venturi-type flow restrictor upstream of the MSIVs. This flow restrictor will limit the amount of coolant lost from the primary system in case of a main

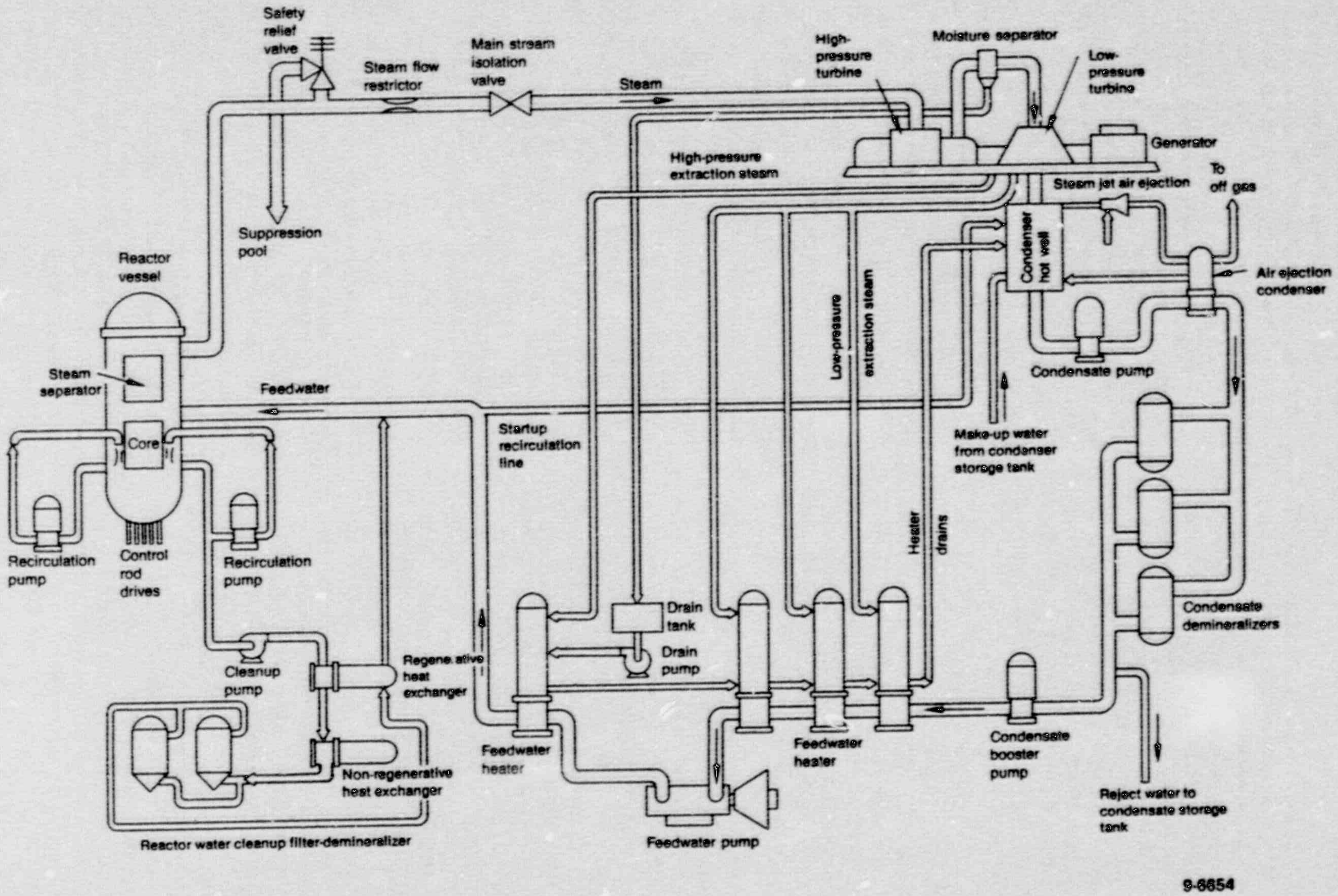

Figure 10.1. BWR main steam and feedwater flow diagram.

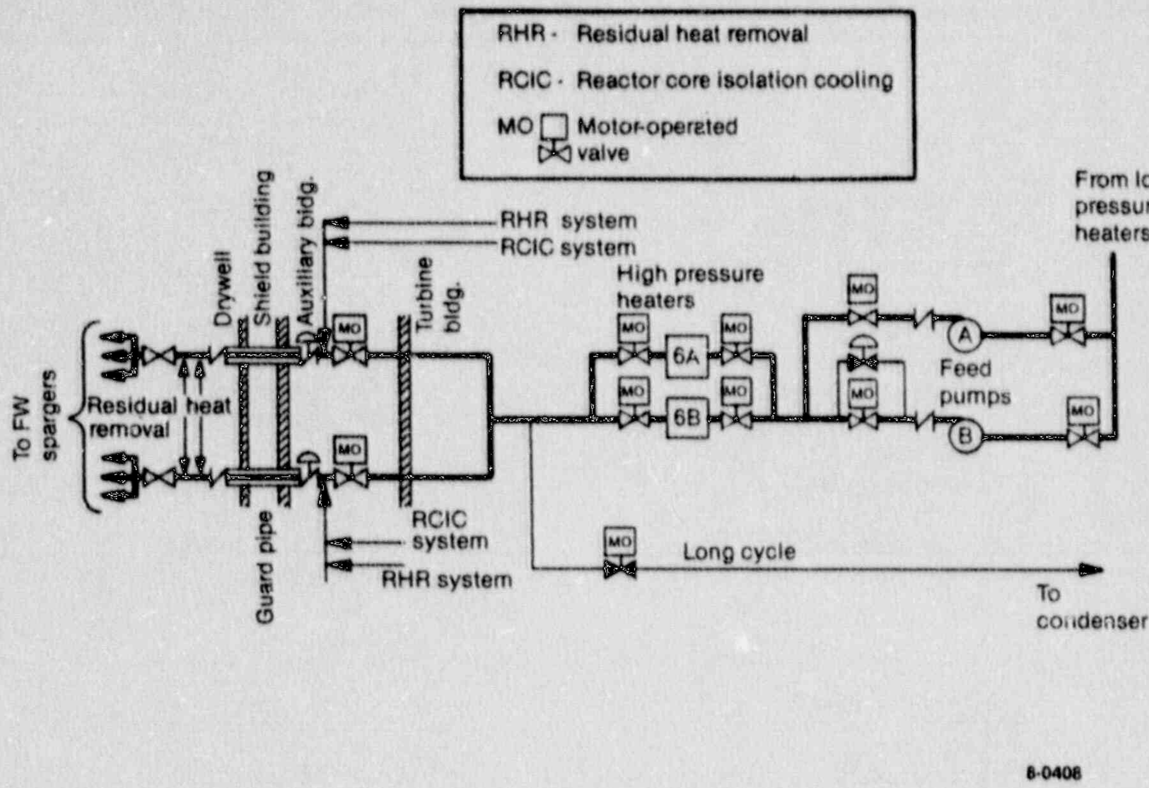

Figure 10.2. Feedwater system schematic.

steam line break outside of containment, and is designed to prevent an uncovering of the core before the MSIVs are closed. As an example, in the event of a guillotine break of one main steam line outside of the containment, a high steam line flow signal should initiate closure of the MSIVs in about 0.5 s, and they are required to be fully closed in 3 to 5 s.[1] The flow restrictor will limit the steam velocity to 183 m/s (600 ft/s) at the throat while the MSIVs are being closed. The steam flow restrictor is made of Grade CF-8 cast stainless steel, selected because of its high resistance to erosion–corrosion.

10.2 Stressors

The BWR feedwater and main steam line stressors of concern include the flow and coolant conditions causing erosion–corrosion, thermal stratification, thermal shock, mechanical shock induced by water or steam hammers, and flow-induced vibrations.

The parameters that control the rate of the feedwater and main steam line erosion–corrosion include piping layout, bulk flow velocity and temperature, moisture content (in steam), pH level, oxygen content, and impurities. The main steam line pipes are not susceptible to erosion–corrosion if moisture is absent. The piping layout may introduce turbulence in the coolant near fittings and geometric discontinuities on the piping inside surfaces, resulting in local flow velocities that may be two to three times higher than the bulk flow velocities. Higher flow velocities tend to increase erosion–corrosion rates in carbon steel piping. The typical pH level in BWR coolants is 7.0 [at 25°C (77°F)], that is, neutral water. The presence of oxygen (>20 ppb in BWR feedwater) is beneficial in reducing erosion–corrosion damage.

The thermal transients that occur during plant heatup/cooldown cycles are major contributors to the fatigue usage factors calculated during the design of the piping. In addition, the horizontal lengths of the feedwater piping are subjected to large temperature differences between the top and bottom portions of the pipe when the plant is at hot standby and during startup and shutdown, when (in both cases) the feedwater heaters are not in use and the feedwater is relatively cold [about 40°C (100°F)] and flow rates are low. The incoming cold feedwater flows along the bottom of the pipe, leaving the lower-density hot water at the top. The stresses induced by these thermal fluctuations were not included in the original fatigue analyses for the piping. Section 6.2 discusses thermal stratification in horizontal feedwater piping in more detail.

Table 10.2. Typical materials of construction[8,9]

Main Steam Piping	
Subcomponent	**Material**
RPV nozzle forging	SA-508 Class 2
RPV nozzle safe end	SA-541 Class 1
Piping connected to safe end	SA-155 Grade KFC60, Class 1
Other piping	SA-106 Grade B
Elbows (forged)	SA-182 Grade F22
Elbows (welded or seamless)	SA-234 Grades WPC, WPB, or WPCW
Flow restrictor	
(Upstream casting)	Grade CF-8, (cast stainless steel)
(Downstream casting)	SA-216 Grade WCB (carbon steel)
Feedwater Piping	
Subcomponent	**Material**
RPV nozzle forging	SA-508 Class 2, 308L (stainless steel clad)
RPV nozzle safe end	SA-541 Class 1 (carbon steel), 308L (stainless steel clad)
Piping connected to safe end	SA-333 Grade 6
Other piping	SA-106, Grade B

The incoming cold [about 40°C (100°F)] feedwater during plant startup and shutdown can also impose a thermal shock on the feedwater piping, which is normally at 216°C (420°F). (A slug of locally cooled feedwater may impose a thermal shock while passing over the warmer portion of the piping.) Thermal shocks introduce skin stresses on the piping inside surface; therefore, the associated fatigue damage may result in crack initiation but not necessarily crack growth. The thermal stressors on the BWR feedwater nozzles are discussed in Section 9.3 of Volume 1 of this report.

Mechanical shock from water or steam hammer events can cause low-cycle fatigue damage to piping systems. The classical water-hammer transient involves a valve closing or a pump starting in a solid water system. Water slugging is another dynamic event of importance that takes place in BWR feedwater lines and is caused by a slug of cold water being rapidly propelled along a straight run of piping until it impacts with a bend or elbow. In general, the magnitude and frequency of water-hammer events are not known, and the resulting overload stresses and fatigue damage are not well accounted for in the design of the feedwater lines. The damage resulting from most water-hammer events has consisted of deformed or failed piping supports or snubbers (broken rods, permanent lockups) and, in some cases, permanently deformed or cracked piping (primarily in branch lines). Detailed pressure tracings have not been recorded at commercial plants during these events.

Steam-hammer[10] and two-phase-flow effects (for example, water entrainment in steam lines or steam bubble collapse) can also cause low-cycle fatigue damage to piping systems. Steam hammers occur during closure of the MSIVs and the turbine stop valves from the momentum associated with the moisture in the steam lines. The main steam lines within the containment are also subject to transient loadings from the actuations of the safety relief valves.

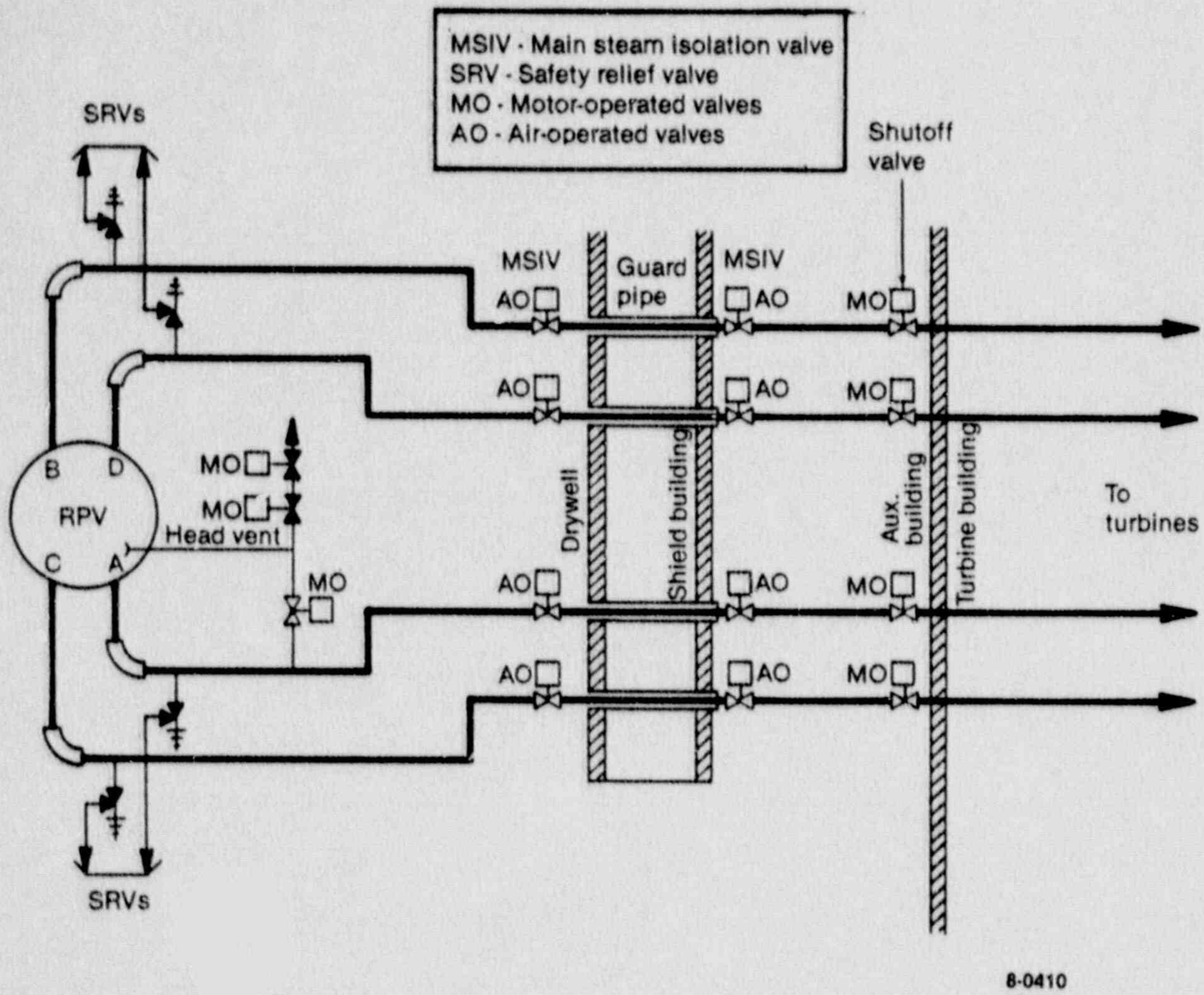

Figure 10.3. Main steam system schematic.

Although the design of the feedwater and main steam systems accounted for steam and water hammers caused by valve–closure events and included an analysis of the shock and thrust forces associated with safety relief valve blowdown, valve actuations and instabilities have caused a number of damaging events. The damage has typically been to small–diameter branch lines, and snubber and pipe hangers outside of the containment. Load magnitudes and durations of steam and water hammers, or of valve actuations, are not precisely known and, consequently, are not well accounted for in the design analyses. Figure 10.5 shows a steam–hammer time–history transient used for the design analysis of a BWR safety relief valve line. As the valve opens, the pressure acts in one direction, creating a large unbalanced force, until the travelling pressure wave reaches the first elbow. When the pressure wave reaches the first elbow, the force is balanced until the wave is reflected, creating a much smaller unbalanced force at about 0.13 to 0.15 seconds in the figure.

Flow–induced vibrations can cause high–cycle fatigue damage to piping systems. As with fluid–hammer loads, the frequency content and magnitude of the loads caused by flow–induced vibrations are not well–known, although some of the frequency content is associated with the rotational speeds of the pumps. In most of the operating plants, flow– and equipment–induced vibration are not explicitly included in the piping system designs, except for a design verification during the acceptance testing stage. During this stage, the vibrations in the systems are judged to be within acceptable limits based primarily on visual observations,[10] as discussed in Section 10.6.

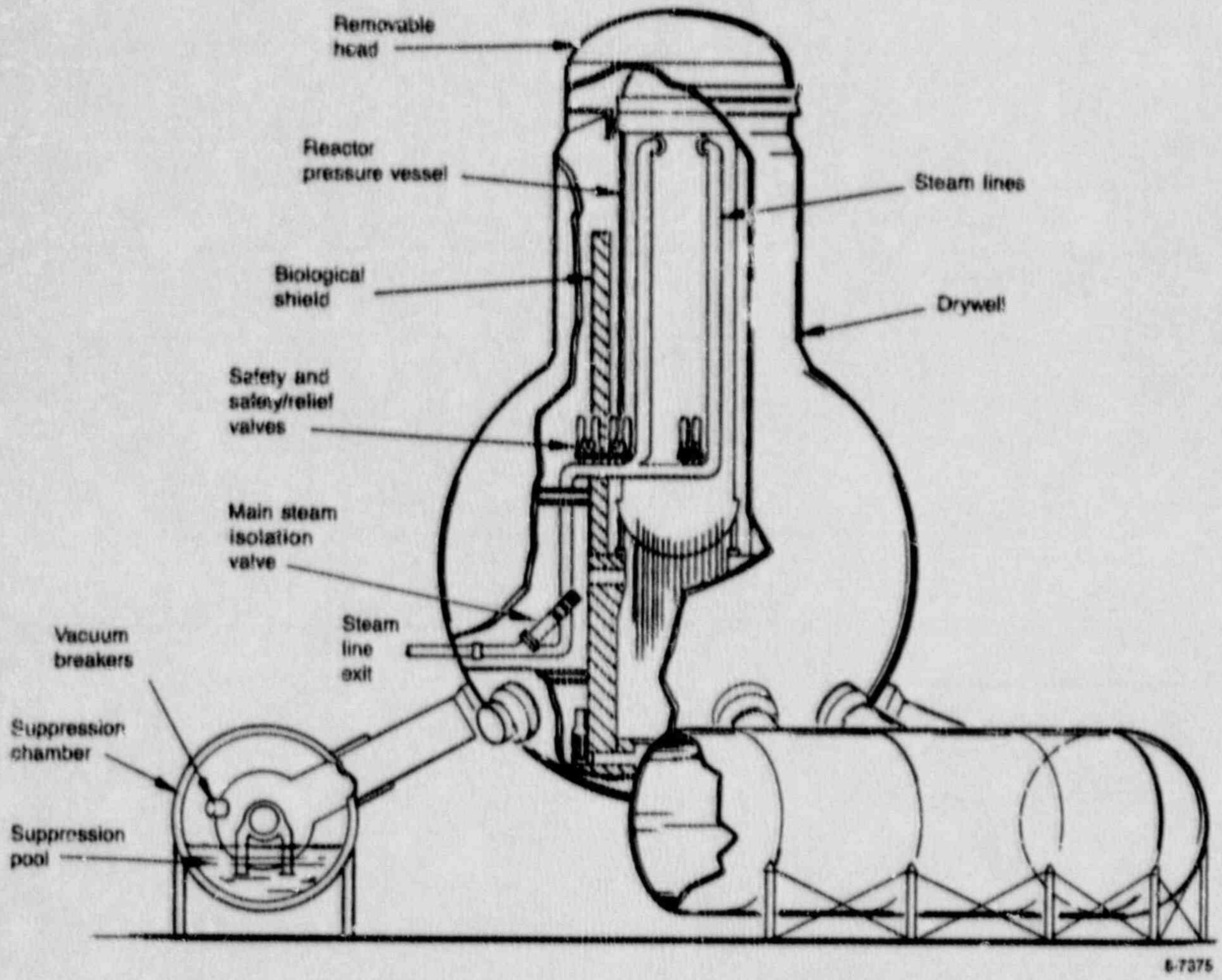

Figure 10.4. Main steam system piping within a drywell torus containment.

10.3 Degradation Sites

The sites in the feedwater systems most susceptible to degradation are near the RPV entrances, the feedwater inlet nozzles, the thermal sleeves, and the feedwater spargers are all subjected to stratified flows, thermal shocks, and flow-induced vibrations. These sites are discussed in more detail in Chapter 11 of this report and in Chapter 9 of Volume 1. Other susceptible sites are the horizontal sections of the feedwater piping undergoing low- and high-cycle fatigue damage caused by stratified flows and thermal shocks.

Two detailed reviews of BWR piping failures have been published.[5,6] These reviews found that most of the reported failures have occurred in the nonsafety-related portions of the feedwater system and that the failures have been confined to the small-diameter piping. A few cracks have been found in small branch pipelines in operating plants. These have been located predominately in socket welds in the 19- to 51-mm-(0.75- to 2-in.-) diameter pipe size range. The cracks were located near pumps and have been attributed to equipment and flow-induced vibration. In Reference 5, the feedwater system failures compose 21% of the total reported failures among BWR subsystems. However, the absolute number of failures is small, only 15 cases in BWR condensate and feedwater systems in 242.6 unit years.[11] The failures reported for the main steam system make up just 7% of the total BWR subsystem failures.

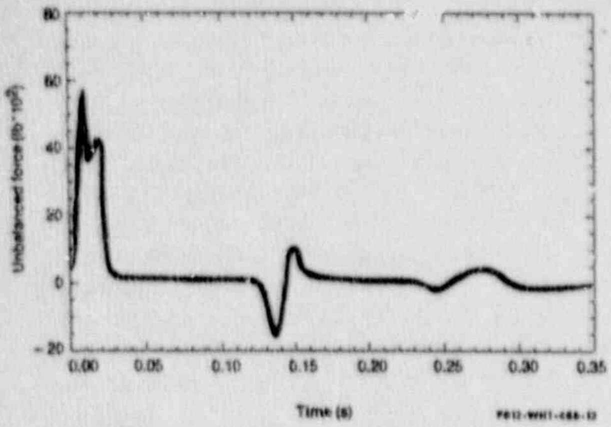

Figure 10.5. Safety relief valve discharge line steam hammer transient used for design.[1]

Until recently, significant degradation caused by erosion–corrosion in feedwater systems containing single–phase coolant was considered unlikely. However, a severe erosion-corrosion-induced failure occurred in the Surry 2 feedwater system, which contains single–phase coolant.[12] Although Surry 2 is a PWR plant, the material, temperatures, and pressures of the feedwater systems of BWRs and PWRs are similar. However, the higher oxygen content in BWR feedwater tends to inhibit erosion–corrosion. Inspections have shown that feedwater line thinning caused by erosion–corrosion has occurred at the following six BWR plants:

Plant	Commercial Operation Date	Degraded Component
Dresden 2	January 1970	Elbows
Duane Arnold	March 1974	Elbows, reducers straight runs
Pilgrim 1	June 1972	Elbows
Oyster Creek	May 1969	Elbows
River Bend 1	October 1985	Recirculation line
Perry 1	June 1986	Straight runs

However, only one of 15 BWR feedwater systems inspected required component replacement because of single–phase erosion–corrosion, whereas 18 of the 39 PWRs initially inspected required component replacement,[13] indicating that this type of aging phenomenon progresses more rapidly in PWRs.

The main steam line subsystems that have been affected most by erosion–corrosion have been the high–pressure turbine exhaust piping and extraction steam lines, including the turbine crossover piping.[14] The piping layouts are responsible for most flow discontinuities that cause turbulence in the steam and the resulting high–flow velocities that contribute to erosion–corrosion damage. Unfavorable piping layouts include elbows without turning vanes, locations with a small radii of change in direction, and branch connections 90 degrees to the normal flow direction. The sites where the distance between a change in direction and other discontinuities is small do not allow turbulence to dissipate and are especially susceptible to higher rates of erosion–corrosion. Areas on the inside surface with discontinuities are susceptible to erosion–corrosion induced by turbulence. Specifically, areas with welding repairs are particularly susceptible to high rates of erosion–corrosion at the leading and trailing edges of the weld.

10.4 Degradation Mechanisms

As discussed above, the main degradation mechanisms that affect the feedwater and main steam lines are erosion–corrosion and low– and high–cycle thermal fatigue. Erosion–corrosion of the carbon steel piping in single–phase and two–phase regimes is discussed in Sections 10.4.1 and 10.4.2, respectively. Although the effects of simple corrosion were included in the design assumptions for the safety related parts of the BWR feedwater and main steam line systems, erosion and erosion–corrosion were not accounted for in the original designs. Thermal fatigue, vibration–induced fatigue, and erosion are discussed in Sections 10.4.3, 10.4.4, and 10.4.5, respectively.

10.4.1 Single–Phase Erosion–Corrosion. The erosion–corrosion of the carbon steel in the BWR feedwater lines is similar to the erosion–corrosion in the PWR feedwater lines discussed in Chapter 6. Therefore, the discussion of erosion–corrosion of presented here has been somewhat abbreviated and a more general discussion of two–phase erosion–corrosion is presented in Section 10.4.2.

Carbon steel is especially vulnerable to erosion–corrosion if the alloy content is low (<0.1%). Typical alloy contents for feedwater and main steam piping materials are listed in Table 6.2. Experience has shown that the use of 2 1/4Cr–1Mo (2–1/4 percent chromium and 1 percent molybdenum) and higher alloy steels provides virtual immunity to erosion–corrosion.[15] Chemical analyses of the failed pipe elbow from the Surry 2 plant found that the steel had low amounts of these elements, particularly chromium (0.07 wt.%).[16] Austenitic stainless steel has been proven to be highly resistant to erosion–corrosion under LWR normal flow conditions.

Water chemistry also influences the rate of erosion–corrosion. The most influential factors are the pH content and the oxygen content. BWRs are designed to operate with high purity, neutral [pH = 7 at 25°C (77°F)] water with 50 to 150 ppb oxygen content, and changing the pH level of the coolant is not a practical measure. Because the wall thinning of BWR feedwater lines has been less of a problem to date than that of PWRs, it appears that the BWR pH is satisfactory when combined with other factors influencing the erosion–corrosion, particularly the higher oxygen content.

Oxygen concentration has a strong effect on the rate of erosion–corrosion. During the early operating period of the Shimane BWR in Japan, high levels of iron (corrosion products) were observed in the feedwater (50 ppb) even though a high efficiency condensate treatment was used.[17] The feedwater contained about 4 ppb dissolved oxygen during this operating period. Adding oxygen gas to the feedwater produced satisfactory corrosion inhibition at dissolved oxygen levels of 20 ppb. Figure 10.6 shows the effect of dissolved oxygen on the corrosion rate and release rate (release of corrosion products into the coolant) for carbon steel in neutral water at temperatures in the range of 200 to 300°C (392 to 572°F).[18] The data were compiled from numerous sources in the literature; thus, temperature and flow conditions were not exactly the same for all tests. However, the figure does give a representative idea of the effect of oxygen on corrosion. This curve indicates that reducing the oxygen level from 200 ppb (0.2 ppm in Figure 10.6 or near the upper range of BWR oxygen levels) to below 10 ppb (0.01 ppm in Figure 10.6) is accompanied by a 50-fold increase (about 0.1 to 5 mg/dm^2/day) in the corrosion rate of carbon steel, and a slightly higher increase in the release rate. (Corrosion and release rates are equal in a BWR environment where equilibrium is established.)

Hydrogen is added to the feedwater at some BWRs to prevent intergranular stress corrosion cracking (IGSCC) of the austenitic stainless steel recirculation piping and reactor internals. This practice, known as hydrogen water chemistry (HWC), reduces the oxygen concentration in the BWR recirculation piping from about 200 ppb to about 20 ppb or less.[19,20] The hydrogen combines with oxygen in the radiation environment of the BWR core region. The reduced oxygen levels in the feedwater system can potentially result in increased degradation by erosion–corrosion. General Electric guidelines consider an oxygen level of 20 to 50 ppb desirable for HWC. Some plants must add oxygen to their feedwater when using HWC, while others do not.

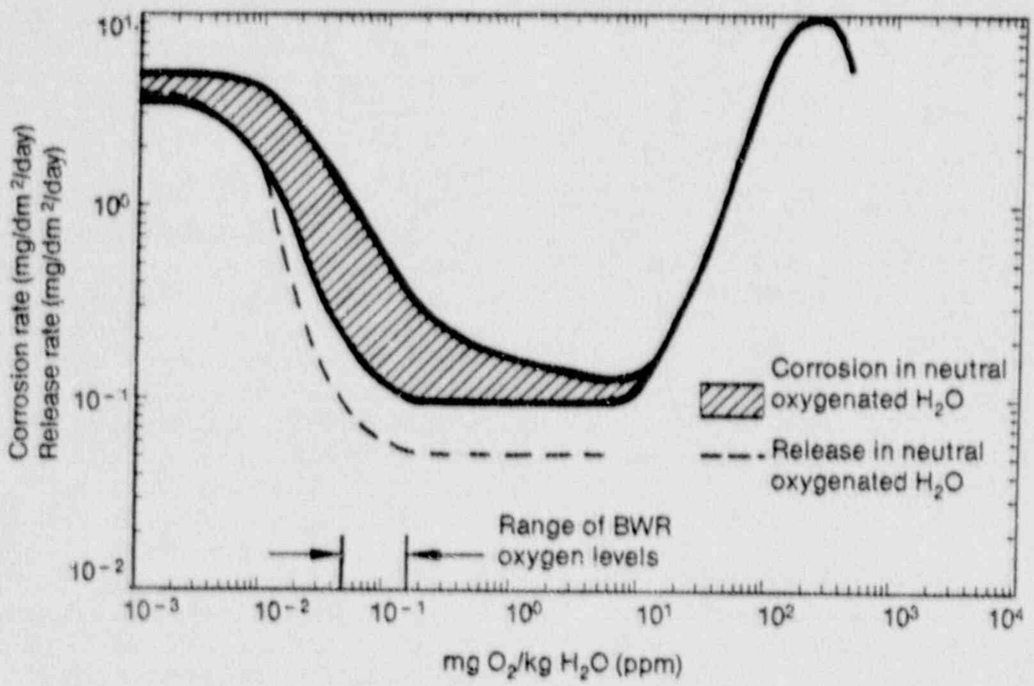

Figure 10.6. Corrosion rates and release rates for carbon steel at different oxygen concentrations for 1000 h. Exposure times at temperatures in the range 200 to 300°C (392 to 572°F).[18] The corrosion and release rates are expressed in units of milligrams of corrosion film formed on or released from a square decimeter area per day.

A series of relatively low-flow laboratory tests have been run to investigate the effect HWC has on various BWR structural materials.[21,22] In general, the effect is beneficial or benign. However, an initial increase was observed in the general corrosion rates of low-alloy and carbon steels. But, once a protective oxide film was formed, the steady-state corrosion rate was found to be only slightly higher in a HWC environment than in a reference BWR environment. Additional tests also indicate that the initial crevice corrosion rate in carbon steel was increased by HWC.

The increase in corrosion kinetics seen in low-alloy and carbon steels indicates that the oxide film that forms under HWC conditions may be less protective than the film that forms under reference BWR conditions. Although the corrosion rate decreased with time under the low-flow-rate laboratory conditions, it is quite possible that under high-flow-rate, or turbulent-flow conditions, a significant increase in the rate of degradation from erosion-corrosion may occur. Bignold et al. found that the rate of erosion-corrosion wear is proportional to the square of the fluid velocity in constant-geometry single-phase laboratory tests.[15] More research in this area is needed to quantify the erosion-corrosion rates for the expected ranges of the important parameters (flow rate, alloy content, oxygen content, and temperature).

10.4.2 Two-Phase Erosion-Corrosion. In an erosion-corrosion process, a corrosive coolant forms an oxide layer on the inside surface of a carbon steel pipe and then an erosive action removes this oxide layer, allowing the exposed surface to continue to corrode. This process of simultaneous oxide growth and removal leads to a reduction of the pipe wall thickness and, ultimately, to catastrophic failure of a pipe under pressure.

Basically, there are two types of erosion-corrosion degradation: a highly localized form occurring at flow discontinuities, and a form known as "tiger striping." The latter is characterized by a mapping or striping of the pipe's inside surface with a rather uniform degradation and is not limited to areas of flow discontinuities. The localized form of erosion-corrosion has occurred in both feedwater and main steam lines, whereas tiger striping has occurred only in wet steam lines at several BWR plants. Significant wall thickness degradation from tiger striping has been documented in numerous straight-pipe sections; however, this degradation does not always occur throughout the full length of the piping.[14]

Examination of worn extraction piping has identified two distinct mechanisms causing erosion-corrosion damage: oxide dissolution and droplet-impact wear.[12,23] Oxide dissolution can occur in both single- and two-phase coolant flow and is highly interactive with flow velocity. The droplet-impact wear mechanism occurs at high flow velocities in two-phase flows. The oxygen content of the main steam system is typically 20 ppm.

Oxide Dissolution. Most theoretical models of erosion-corrosion are based on a flow-enhanced dissolution of the oxide layer that forms on the surface of the steel.[24,25,26] The oxide layer dissolution occurs when hydrogen present in the water or formed during oxidation reduces the magnetite. Under steady-state conditions, erosion-corrosion results in linear corrosion kinetics (time dependence) and high corrosion rates. The results predicted by these theoretical models and by the data from laboratory tests are in general agreement with the results observed in operating systems. The principal factors affecting erosion-corrosion (that is, the stressors mentioned in Section 10.3) are as follows:[14]

- Steam quality
- Temperature
- Piping material composition
- Coolant chemistry (including oxygen and pH)
- Flow-path geometry and flow velocity.

Erosion-corrosion has been observed in piping carrying wet steam. Its occurrence has not been observed in systems carrying dry steam. This is in keeping with the generally held view that the process takes place by a surface dissolution mechanism. Laboratory data do not show a clear indication of how the rate of erosion-corrosion is affected by the moisture content of wet steam. However, field data indicate that the greatest degradation is seen in the piping containing steam with a higher moisture content, such as the turbine crossover piping and the exhaust and extraction piping of high-pressure turbines.

The rate of erosion-corrosion has been found to be strongly temperature dependent. Data derived from damage to carbon steel components in wet-steam turbines (two-phase conditions), presented in Figure 10.7, show a maximum wear rate at about 180°C (350°F).[27] Above and below this temperature the erosion-corrosion rate drops rapidly. The curve in

Figure 10.7 is based on the results from an initial inspection (in 1963) of a steam system at a 16-MW experimental nuclear power plant in Kahl, Federal Republic of Germany. The materials and environment of the steam system of the experimental reactor may not be the same as those of United States BWR steam systems, and the temperature associated with the maximum erosion-corrosion rate may be different for BWR steam lines. Nevertheless, the available data indicate that the shape of the curve is somewhat generic, with erosion-corrosion rates decreasing at temperatures above and below the temperature at which the maximum erosion-corrosion rate occurs. Figure 6.10 shows a similar shape for the temperature/ erosion-corrosion rate curve under PWR conditions.

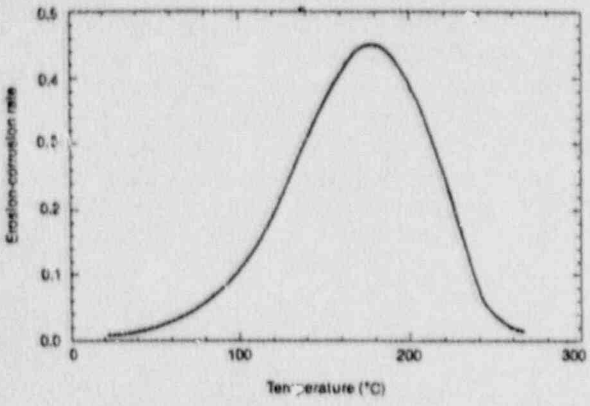

Figure 10.7. Effect of temperature on erosion-corrosion in two phase flow.[14]

As mentioned in Section 10.4.1, the rate of degradation by erosion-corrosion is strongly affected by the amounts of chromium, molybdenum, and copper in carbon and low-alloy steels. Tests by Kunze and Nowak in a wet steam (pH ~ 9)[a] loop show that the rate of erosion-corrosion wear for carbon molybdenum steel (German specification 10 CrMo 9 10) is nearly one-third the rate for carbon steel (German specification C22.8), and that chromium-molybdenum steel is 10 times more resistant to wet-steam erosion-corrosion than carbon steel.[28]

The typical oxygen content in BWR main steam lines is about 20 ppm, approximately 100 times the oxygen content in the feedwater system. The pH in the steam lines is 7, and the conductivity is 0.057 μS/cm.

a. A pH ~ 9 is typical for PWR secondary coolant.

The oxygen content in the main steam lines reduces to about 7 ppm when hydrogen water chemistry is used, but this oxygen content is still high and will probably produce a good protective oxide film on the inside of the steam piping.

As was observed in single-phase systems, degradation from wet steam erosion-corrosion generally occurs in regions of high-flow velocity or high turbulence. The degradation tends to be localized in regions of turbulent flow and is found in areas of flow discontinuities such as pipe junctions, elbows, and joints. Kunze and Nowak observed an increase in the erosion-corrosion wear rate as the flow rate increased in their two-phase flow laboratory tests.[28] In general, the erosion-corrosion rate can be expected to be higher in systems with higher bulk flow rates. However, high local velocities caused by flow geometry and local mass transfer at the surface caused by turbulent mixing appear to be the most important parameters affecting the erosion-corrosion rate. Experiments have established that local-flow velocities in elbows, for example, can be two to three times higher than the bulk-flow velocities.[12,29,30]

A three-layer stainless steel coating designed to prevent erosion-corrosion has been developed and successfully tested in pipes containing wet steam at ten Swedish plants (five BWR and five PWR).[31] The first application was in a BWR plant in 1977. The coating is flame-sprayed on the interior of the piping. The top layer is Type 304 stainless steel, which is very resistant to erosion-corrosion. The bottom layer is chosen to provide a sufficient mechanical bond to the carbon steel pipe, and an intermediate layer provides bonding between the top and bottom layers. The total thickness of the three layers is usually about 0.5 mm (0.020 in.). In situ application requires a minimum pipe diameter of about 600 mm (24 in.), while shop application requires a minimum pipe diameter of about 100 mm (4 in.).

Droplet Impact Wear. A second mechanism associated with wet steam erosion-corrosion damage is droplet impact wear, that is, the mechanical erosion of the oxide film by liquid droplets. The impact of liquid droplets on carbon-steel oxide films can produce a matrix of cracks and subsequent fatigue failure of the films, and expose the underlying metal surfaces to the corrosive action of the coolant. This wear mechanism occurs under certain conditions at elbows and fittings where the flow changes direction, predominantly on the outside radius of the bend in the direction of the flow, as shown in Figure 10.8.[23] In contrast, damage caused by oxide dissolution occurs on the inside radius of the bend where flow separation causes turbulence

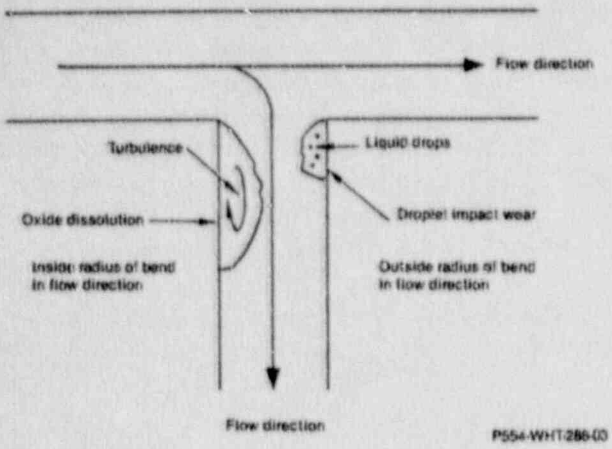

Figure 10.8. Potential sites for the two different types of wet steam erosion–corrosion damage.

(also shown in Figure 10.8). The droplet impact wear mechanism requires the presence of droplets, so this mechanism occurs only in pipes carrying two-phase flow.

The liquid phase in a BWR steam line generally flows in a thin layer near the main steam line pipe wall, while the vapor forms the core of the flow and moves much faster than the liquid phase. This velocity difference creates shear forces at the liquid–vapor interface; if this force is greater than the surface tension force at the interface, some liquid will be sheared off the liquid layer and carried over with the vapor. This liquid will form droplets, which will be accelerated by the vapor and become entrained in the vapor core. A fraction of entrained liquid droplets will impinge on the oxide film on the main steam line inside surface. The piping layout determines what portion of the entrained liquid droplets will impinge on the oxide film. The other parameters determining the film failure are the oxide hardness, and the critical strain and the fatigue loads required to fracture the oxide film.

Reference 23 provides simple models for estimating oxide dissolution and droplet–impact wear. The model developed to describe droplet–impact erosion does not contain a strong temperature dependence, but does have a strong dependence on flow velocity (fourth power dependence). Therefore, droplet–impact wear is expected to be of importance at high–flow velocities.

Droplet (moisture) removal constitutes a straightforward means of minimizing droplet–impact wear damage. On the other hand, addition of small amounts of alloying elements, such as chromium, copper, and molybdenum, to the carbon steel can reduce erosion–corrosion damage from droplet–impact wear by factors of up to 100.[23]

10.4.3 Thermal Fatigue. Design fatigue calculations are conducted for Class 1 piping; however, the only calculations for the B31.1 balance–of–plant piping are for thermal deflections.[1] Thermal fatigue is more severe in the feedwater portion of the BWR piping than in the main steam system. For example, the calculated fatigue usage factor for the feedwater nozzle safe end is 0.95 (the allowable usage is 1.0), whereas the maximum fatigue usage calculated for any portion of the main steam system within the containment is only 0.06.[9] Thus, this section will focus on thermal fatigue of the feedwater lines.

The Class 1 plant design analyses have considered the well–defined thermal transients such as plant startup and shutdown. However, as discussed in Section 10.3, the horizontal portions of the BWR feedwater lines can be subjected to significant temperature differences between the top and bottom of the pipes when the plants are at hot standby conditions and during startup and shutdown when the flow rate is less than the full power flow rate. At very low flow rates, the incoming, relatively cold ~40°C (100°F) feedwater flows along the bottom of the pipe, leaving the lower density hot feedwater 216°C (420°F) at the top. A thin mixing layer is formed at the interface of hot and cold feedwater flows. This thermal stratification was not considered at the time of the original design analysis and can cause pipe degradation by fatigue that may crack the pipe wall.

The stratified flows contribute to high axial bending stresses in the horizontal portions of the feedwater lines. Therefore, the horizontal portions of feedwater lines experience low–cycle fatigue damage as the interface level rises from the bottom of the pipe to the top and returns to the bottom again. In addition, the turbulence in the mixing layer at the interface between the hot and cold fluids introduces cyclic thermal stresses at the inside surface of the pipe in the vicinity of the mixing layer. These stresses cause high–cycle fatigue damage (see Section 6.5).[33,34] The overall fatigue damage caused by this behavior is difficult to estimate.

On–line monitoring of piping wall temperatures and coolant temperature, pressure, and flow rate is needed to determine the transient thermal and mechanical loads caused by different stressors and to estimate the resulting low–cycle fatigue damage. The Electric Power Research Institute (EPRI) is developing an automated plant fatigue monitoring system that can accurately measure fatigue usage, including the low–

cycle fatigue caused by flow stratification.[35] The system was applied to the Quad Cities 2 BWR feedwater nozzles.[36] Data from 12 instruments in each of the two feedwater loops were used to determine the fatigue usage during the demonstration period. Other evaluation projects underway include feedwater nozzle monitoring at the Oyster Creek and Susquehanna 1 plants.

The ASME Code fatigue curve for carbon steel and the stress analysis methods for fatigue are discussed in Chapter 3. The curve is based on data from uniaxially loaded specimens strain cycled in air (no environmental effects). Strain values were converted to stress units by means of the elastic modulus. A least-squares curve was fitted through the data, and a safety factor of 2 on stress or 20 on cycles, whichever was more conservative for a given point, was used to establish the design curve. However, the carbon steel piping is exposed to a BWR environment and may experience corrosion fatigue at stresses far less than predicted by the ASME Code fatigue curves. Thus, even if all the various fatigue loadings had been properly considered in the original design of all the feedwater and main steam piping locations, the potential still exists for thermal fatigue failures because environmental effects have not been explicitly considered in the ASME curves nor in the original plant design.

Fatigue tests performed by General Electric under EPRI sponsorship show that the effect of the standard BWR environment on SA-106 Grade B and SA-333 Grade 6 steels can completely erode the "2 and 20" margin in the ASME Code fatigue design curve.[37] Crack initiation in the BWR environment tests occurred solely at the weld preparation discontinuity or at the interface of the weld fusion line and the base metal. These kinds of notches were innocuous in tests conducted in air (the tests forming the basis for the ASME Code design curves were also performed in air). However, in high-temperature oxygenated water, these locations acted as crack-initiation sites. Such cracks developed at far fewer cycles than in-air predictions would indicate.

The General Electric test data are shown in Figure 10.9 plotted as pseudo-stress amplitude (S_a) versus cycles to failure (or crack initiation, depending on specimen type).[37] For comparison, the ASME Code mean data and design curves are also included in the figure. The room-temperature-air data (for smooth specimens) agreed with the ASME Code mean data. Compact-tension specimens tested in air at temperatures of 232°C (450°F) also had fatigue lifetimes equivalent to the ASME Code mean data curve, but at 288°C (550°F) approximately a factor-of-two reduction in cyclic life occurred. There was a further reduction in fatigue lifetimes in water environments of 288°C (550°F), the magnitude depending on loading conditions. [Because the BWR feedwater temperature is 216°C (420°F), this effect would not be as pronounced as for the steam system, where the temperature is approximately 288°C (550°F).]

General Electric has defined the pseudo-stress amplitude as

$$S_a = 1/2\ K_t\ K_e\ S_n \qquad (10.1)$$

where K_t is an elastic stress concentration factor, K_e is a plasticity correction factor that accounts for loading in excess of the material's yield strength, and S_n is the applied stress range. General Electric also has determined that, although the ASME Code fatigue curve contains a correction for the effects of maximum mean stress, this correction is incomplete—mainly because of the exclusion of strain hardening effects. General Electric has developed a new fatigue analysis procedure that they feel accounts for the effects of environment, strain hardening and mean stress and adheres to the conservatisms that were desired in the original ASME Code philosophy. The following formula is similar to Equation (10.1), but accounts for more factors:

$$S_a = 1/2\ K_f\ K_n\ K_m\ K_{en}\ M\ K_e\ S_n \qquad (10.2)$$

where K_f is the fatigue strength reduction factor, K_n is a correction factor for local notch yielding, K_m is the mean stress correction factor, K_{en} is an environmental correction factor, and M is a modifying factor for K_{en} to account for temperature and environment variation during a transient.

General Electric calculated that the fatigue usage factor for a typical feedwater system, computed by its alternate rules for carbon steel (Equation 10.2), was up to eight times higher than the value computed by the conventional ASME Code rules.[37] For example, the usage factor increased from 0.013 (ASME Code calculation) to 0.103 (Equation 10.2) at one elbow. Seventy percent of the transients considered in the sample case occurred at temperatures below 232°C (450°F), so additional fatigue usage caused by temperature effects needed to be included for only about 30% of the transients. The maximum temperature the feedwater line was 254°C (490°F) in the sample case.

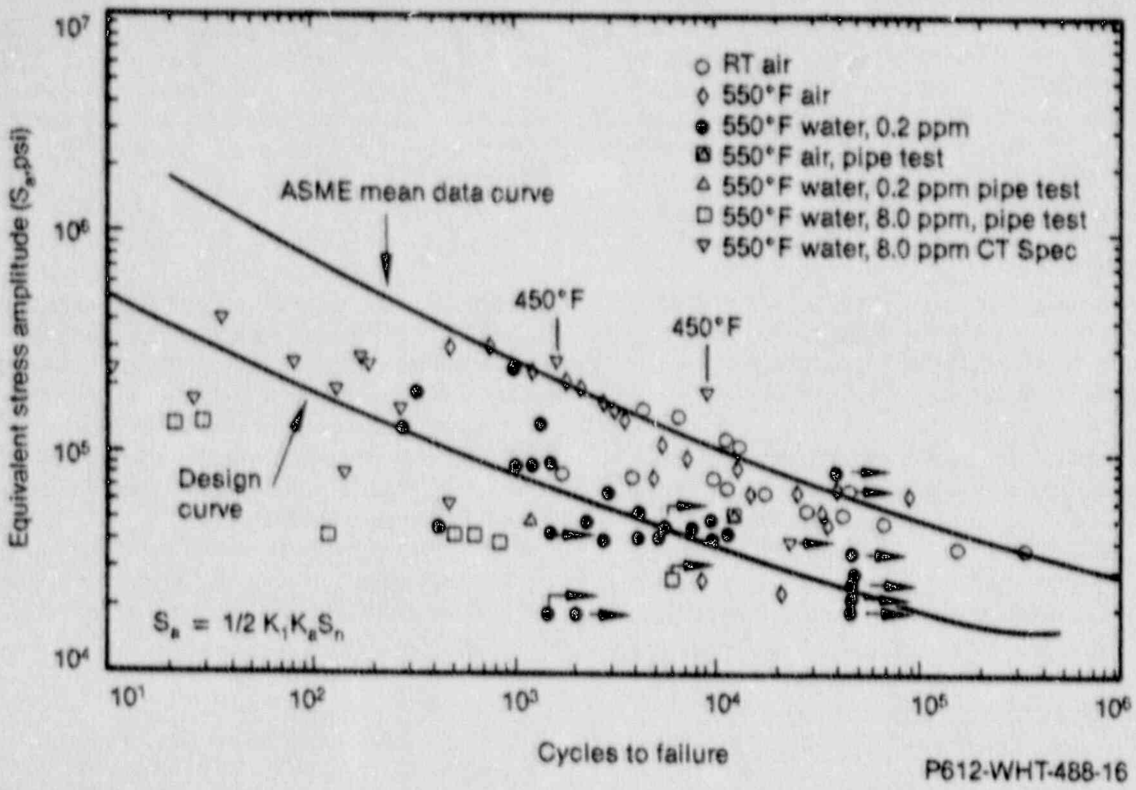

Figure 10.9. General Electric fatigue data plotted in accordance with modified ASME Code design curves for carbon steel.

Assuming that the same environmental effects apply to main steam lines, resulting in an eight–fold increase in fatigue usage, the fatigue usage in the main steam lines could increase from 0.06 to 0.48. If such an increase is substantiated, the inservice inspection program would be affected because Class 1 piping with a calculated fatigue usage greater than 0.4 requires inspection of its welds during each inspection interval. The temperature of the main steam line is 288°C (550°F); thus, an additional factor of 2 might have to be included, to properly account for temperature transients higher than 232°C (450°F). This would result in an even higher fatigue usage factor, of up to 0.96, which is a conservative upper bound. The General Electric design procedure may be added to the ASME Code as an appendix to Section III.

One major difference between the General Electric test parameters and BWR plant conditions is the type of loading. The General Electric low–cycle (<10^5 cycles) fatigue tests were conducted using mechanical loads,[38] rather than thermal loads, which also induce fatigue in nuclear power plant piping. It is generally assumed that the resulting fatigue damage is the same regardless of the source of the loading. However, the crack initiation and crack growth mechanisms for carbon steel piping in a BWR environment may be different when the fatigue is caused by rapidly applied mechanical loads rather than slowly applied thermal loads.

Carbon steel piping materials become increasingly more susceptible to corrosion fatigue or environmental degradation when they contain sulfur. The specifications for carbon steel piping materials, such as SA–106 Grade B and SA–234 Grade WPB, allow 0.058% sulfur content. Similar detrimental effects of sulfur in low–alloy pressure vessel steels and steam generator shell material are well–known.[39,40] Recent BWR environment fatigue tests on Japanese piping steels similar to SA–106 Grade B, but containing less sulfur, did not show any evidence of environmental degradation.[41]

The use of hydrogen water chemistry will reduce the oxygen level in the BWR environment. A lower–oxygen environment is likely to yield lower fatigue crack growth rates in carbon steel piping.[39]

10.4.4 Vibration–Induced Fatigue. Vibration–induced fatigue is caused by flow–induced vibrations (such as in orifices), steam and water–hammer events, water slugging, and mechanical vibration (such as pump rotation). A number of cracks have occurred in small pipelines at most operating plants. These have been located predominantly in socket welds in the 19– to 51–mm– (0.75– to 2–in.–) diameter pipe size range. The cracks were located near pumps,[42] and have been attributed to equipment- and flow-induced vibration. The main steam lines have probably experienced less vibration-induced (including steam hammers, relief valve openings, etc.) fatigue than have the feedwater lines. However, the magnitudes and frequencies of occurrence of these vibrations in both feedwater and main steam lines are not well-known. In general, high-cycle vibration fatigue analyses have not been conducted, even for ASME Class 1 components. The defense against high-cycle fatigue has been good design practices based on judgment and experience, and visual monitoring during preoperational testing.

Water hammer is a multicycle load induced by transient pressure pulsations in the feedwater fluid. It can result from fast closure of a check valve caused by a flow reversal or intermittent operation of the feedwater valves. A steam hammer is a similar event that can take place in the main steam lines during turbine stop valve closures following a loss of load, rapid openings of SRVs, or sudden closure of MSIVs. The openings of the SRVs can result in large dynamic loads on both the main steam header and the relief-valve vent piping.[10]

Water slugging is a single-pulse load induced when a slug of water is accelerated through the piping. Pump startup in the feedwater lines can cause this to occur, especially if the discharge lines have been voided. The water slug causes piping loads at flow discontinuities and elbows. If the slug impacts a stationary column of water, a pressure transient will be generated in the water. Water slugging can also occur in main steam lines as a result of water accumulating in the line, followed by a valve opening that reestablishes flow in that line.[10]

Water and steam hammers and water slugging are usually short-duration events, typically occurring in less than 1 s, but with dramatic effects. Large unbalanced forces exerted on the piping typically damage the pipe supports and restraints. In severe cases, the piping may also be damaged.

The Dresden and Quad Cities plants have been particularly plagued by vibration problems in the feedwater lines. Undesirable feedwater piping oscillations from 1970 to 1975 resulted in cracked and broken small-diameter lines connected to the feedwater system. A number of system modifications were made to correct the problem, as listed in Table 10.3.[a] After about a 10-year relatively trouble-free period and after a new control system was added in 1986, vibration problems recurred in the Dresden 2 and 3 plants. Dresden's most severe incident, which occurred on August 7, 1987, broke a feedwater pump flow instrument sensing line, loosened the feedwater regulating station floor plate grout, bent the feedwater pump discharge pipe clamp, and damaged the piping insulation. Postevent examinations of the damage to the bent pipe clamp determined that the vibrational loads were three times greater than anticipated in the original design analysis. No single root cause has been identified and additional instrumentation has been added to assist in understanding the problem. Although the cause of this vibration is unknown, it appears that events may occur over the course of a plant lifetime that can induce unexpected stresses and subsequent piping system failures.

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a. M. J. Russell, private communication, EG&G Idaho, Inc., Idaho Falls, ID, September 1987.

Table 10.3. Quad Cities and Dresden feedwater system events

Date	Description
Fall 1970	Feedwater pump design deficiencies cause Dresden Unit 2 piping oscillations.
Winter 1970-1971	Dresden Units 2 and 3 feedwater pump casings and impellers modified. Vibrations reduced.
February to November 1973	Feedwater flow control systems at Quad Cities and Dresden modified to improve system performance.
Fall 1973	Quad Cities Units 1 and 2 feedwater regulating valve supports installed. Regulating valve controller modified. Flow control system modified.
June 1974	Large feedwater piping oscillations on Quad Cities Unit 2. Feedwater regulating station low-flow line cracked.

Table 10.3. (continued)

Date	Description
June 1974	Feedwater piping oscillations damage pipe supports on Dresden Unit 3.
August 1974	Quad Cities Units 1 and 2 feedwater regulating station minimum flow line rerouted. Vibration detection instrumentation installed. Feedwater level control system modified.
Winter 1974	Dresden Units 2 and 3 feedwater regulating valve controller modified. Flow control system modified.
August 1975	Large feedwater piping oscillations in Quad Cities Unit 2 sever feedwater regulating station low–flow line.
August 1975	Feedwater piping oscillations break two small feedwater drain lines on Quad Cities Unit 2.
October 1975	Additional restraints added on Quad Cities Unit 2 feedwater regulating valve minimum flow piping.
Summer–Fall 1976	Dresden 2 and 3 feedwater regulating station minimum flow line rerouted. Vibration detection instrumentation installed. Feedwater level control system modified.
1976	Feedwater pipe supports added to Dresden 2 and 3.
November 1977 to June 1978	Dresden Unit 2 and Quad Cities Units 1 and 2 drag valve installed in place of original feedwater regulating valves.
Summer 1986	Dresden Unit 3 feedwater pump impeller replaced.
August 1986	Dresden Unit 3 feedwater control system upgraded to a Bailey Network 90.
Summer 1987	Dresden Unit 2 feedwater control system upgraded to a Bailey Network 90.
July 1987	Dresden Unit 3 feedwater piping oscillations result in a main turbine trip and reactor scram.
July 1987	Dresden Unit 2 feedwater level control regulating valve causes low–level reactor scram.
August 1987	Dresden Unit 3 large piping oscillations break a small feedwater instrument line and a reactor water cleanup drain line, and cause pipe support damage.

There are two major concerns related to high–cycle fatigue analysis. The first is the existence of a fatigue limit, and the second is the usage factor at which fatigue failures may take place. The fatigue curve for many metals flattens at a given number of cycles (10^6 to 10^8 cycles is generally considered typical for steels). The stress at this point is called the fatigue limit. If the alternating stress for a particular event does not exceed the fatigue limit, the member will not fail from high–cycle fatigue, that is, the number of allowable cycles at this stress approaches infinity. This concept is based on material tested in the air, but the existence of a fatigue limit in the presence of corrosion–assisted fatigue has not been proven. Therefore, use of a fatigue limit concept in high-cycle fatigue analyses is not reliable. The ASME Code Subgroup on Fatigue Strength is evaluating the extension of the fatigue design curve for carbon steels to above 10^6 cycles. An approach where the fatigue design curve has a shallow slope (for example, -0.05) beyond 100 million cycles is being considered and is probably more reasonable and conservative to use for long-life fatigue damage assessment than a fatigue limit where no fatigue usage is accumulated at stresses below the fatigue limit.

Fatigue failure predictions based on Miner's rule, (which assumes a simple linear summation of the ratios of actual cycles divided by cycles to failure at a given stress) may be in error because it does not account for the effect of load sequence. For example, if low-amplitude alternating stresses capable of causing high-cycle fatigue damage are preceded by high-amplitude stresses that may cause crack initiation, then failure may take place at a fatigue usage factor less than one.[43]

10.4.5 Erosion. One BWR feedwater system recirculation-to-condenser line (often referred to as the minimum flow line) has experienced leakage because of erosion.[13] In 1987, a 45-degree elbow (Schedule 160, 5 Cr 1/2 Mo steel) in a feedwater pump minimum flow line at the LaSalle 1 plant was found to have through-wall pinhole leaks caused by erosion. Further inspection in the LaSalle 2 plant found a 6.35-mm (1/4-in.) hole located directly downstream of a feedwater minimum flow line elbow. The erosion was attributed to the design of the minimum flow control valves and the geometry of the downstream piping. The valves at the LaSalle plants were not designed to be leak tight. Feedwater leaking past the seat flashed to steam because of the drop in pressure caused by the vacuum in the condenser. The geometry of the valve disc directed the steam like a jet immediately on the wall of the downstream elbow or reducer, causing the erosion.

10.5 Potential Failure Modes

The two major degradation mechanisms, erosion-corrosion and fatigue, can cause cracks or pinholes that result in small leaks, or they can weaken a system and reduce the safety margin, enabling another event such as a pressure pulse or a water or steam hammer (that would not normally cause failure) to cause a rupture.

The worst failure would be a complete rupture of the piping in the vicinity of the reactor vessel, within the containment. Such a failure could not be isolated and would result in a loss-of-coolant accident. The most severe location is the feedwater line nozzle into the RPV. Thermal fatigue has caused cracks in the piping at this location in some BWRs in the past, and a complete rupture would result in both loss of feedwater and blowdown (depressurization) of the reactor pressure vessel. A less severe accident involves leakage in the feedwater line but not a complete pipe rupture, enabling at least some feedwater flow to the reactor.

To illustrate the potential failure modes, several past piping failures will be discussed. PWR events are included because the degradation mechanisms for both PWR and BWR feedwater and main steam piping are essentially the same. However, the secondary coolant in PWR plants has significantly smaller amounts of oxygen than normally found in the BWR feedwater systems and, therefore, PWR secondary piping systems are more susceptible to erosion-corrosion damage. More detail regarding the erosion-corrosion failures in PWR feedwater lines is reported in Section 6.5.1.

Unit 2 at the Surry Power Station (Westinghouse PWR) experienced a catastrophic failure of a main feedwater suction pipe in 1986, resulting in fatal injuries to four workers. This failure occurred on the outer radius of a 90-degree (long radius), 457-mm-(18-in.-) diameter elbow that was connected downstream of a flow-splitting tee. The break initiated in the carbon steel elbow material (A234 Grade WPB), not in either weld.[44] The nominal wall thickness of the suction piping is 13 mm (0.500 in.). The wall had been generally eroded to about 6.4 mm (0.25 in.). There were localized areas of thinning to about 1.5 mm (0.06 in.). Investigation of the accident and examination of data led to the conclusion that failure of the piping was caused by erosion-corrosion of the pipe wall. Although erosion-corrosion pipe failures had occurred in other carbon steel systems, particularly in small-diameter piping in two-phase systems and in water systems containing suspended solids, there have been few previously reported erosion-corrosion failures in large-diameter piping systems containing high-purity water.[45]

A water-hammer transient at the Indian Point 2 (Westinghouse PWR) nuclear power plant in 1973 resulted in a 180-degree circumferential fracture of the 457-mm- (18-in.-) diameter main feedwater line at the anchor point where the pipe penetrated the reactor containment structure.[42] Gross thermal deformation of the metal containment liner near this juncture resulted because of water sprayed from the ruptured pipe, and a large bulge occurred in the horizontal run of pipe to the steam generator nozzle. The crack at the anchor point at the containment wall was caused by excessive bending stresses, possibly resulting from dynamic reaction forces elsewhere in the line. The cause of the water hammer was attributed to steam condensation in the horizontal feedwater line following an interruption of feedwater flow. Based on the bulge in the pipe, an equivalent static pressure of 34–41 MPa (5–6 ksi) was estimated. This is consistent with results from water-hammer tests performed at the Tihange plant in Belgium.[5]

Following an outage of about five days in 1984, the WNP-2 (BWR/5) plant began to slowly admit feedwater. About 15 minutes after beginning flow, personnel in the area heard a dull thud. Subsequent investigations revealed that several feedwater pipe hangers and snubbers had been damaged, and a flange loosened, allowing a small leak of feedwater.[46,47] The event was initially reported as a water hammer, but after consulting with experts and considering other circumstances, the WNP-2 staff determined that the event could have been the result of thermal deflection induced by stratified flow in the pipe. The difference in temperature between the top and bottom of the pipe could have caused the pipe to bend, pulling the hangers out of their supports. To verify that flow stratification was the cause of the damage, the piping system was instrumented to record pipe movement, and differences in temperatures between the top and bottom of the pipe. Despite procedures designed to prevent recurrence of the event, it happened again following a scram at 60% power. The instrument recordings on the feedwater lines indicated flow stratification as the main cause for the phenomenon. Recently, stratified flow caused bowing in the Nine Mile Point Unit 2 feedwater lines during a plant startup and caused damage to the flanges.[48]

The USNRC has advised other plants to consider whether suspected water-hammer events might instead be attributed to pipe bending because of a thermal stratification phenomenon similar to the one that occurred at WNP-2.[46] There is potential for occurrence of this event when the feedwater is cold and the flow rate is low.

10.6 Inservice Inspection and Surveillance Requirements

Formal guidelines for inspection of pressure piping are listed in Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1 of Reference 49, for Class 1, 2, and 3 systems, respectively. Only the weld areas of the Class 1 systems, such as the BWR feedwater piping inside containment, must be inspected. Inspection of areas of piping away from weld zones is not required. However, in response to a USNRC bulletin based on the Surry pipe break incident, most utilities have instituted increased inspection programs for their feedwater system piping. As an aid to utilities in identifying problem areas, EPRI has developed the CHEC and CHECMATE personal computer programs.[50,51] These programs use plant physical, chemistry, and flow data to determine areas in the piping most susceptible to erosion–corrosion. The ASME Section XI Committee is currently developing inspection procedures to detect wall thinning in piping. EPRI has also developed guidance for selection of examination techniques for specific plant situations (including ultrasonic, radiographic, and visual methods), and has provided suggestions for additional detailed examinations if erosion–corrosion is detected.[52]

The extent of wall thinning caused by erosion–corrosion may be highly localized, and the variation of erosion–corrosion degradation can be large within a very short distance. This variation makes reliable inspection for erosion–corrosion damage extremely difficult. Manual ultrasonic techniques may satisfactorily measure average thicknesses but not minimum thicknesses.[53] In addition, current ultrasonic techniques do not properly measure wall thicknesses in regions with complex geometry such as pipe welds, reducers, elbows, tees, etc. Therefore, there is a high probability that the site with minimum thickness will not be located. In addition, the manual ultrasonic technique generally lacks repeatability and reliability because it is highly operator dependent. Therefore, an automatic ultrasonic technique is needed for erosion–corrosion damage detection. Advanced inspection and monitoring techniques for wall thinning are discussed in Section 6.6.

All the locations in the feedwater and main steam piping systems that are susceptible to erosion–corrosion must be identified and properly inspected. These locations may be identified using available guidelines. However, further assessment and modification of these guidelines are probably needed. The results of the various thickness measurements should be evaluated considering the highest possible transient pressure, because ultimately, such transient pressures could cause a catastrophic failure of a degraded pipe.

The ASME Code[3] (Paragraphs NB-3622, NC-3622, and ND-3622) and the ANSI Standard[4] (Paragraph 101.5) require that piping be observed under initial or startup conditions to ensure that vibration is within acceptable limits. The USNRC also has included piping vibration testing in several regulatory guides.[54,55] The ASME has written an operation and maintenance standard[56] detailing the requirements for vibration testing of nuclear power plant piping systems. This standard addresses steady-state and transient vibration testing, acceptance criteria, methods for determining acceptable vibration limits, and recommendations for corrective action. Qualified inspectors witness the piping responses during applicable flow modes. They may use portable vibration monitoring equipment.[10]

10.7 Summary, Conclusions, and Recommendations

The principal mechanisms responsible for age-related degradation of the feedwater and main steam line piping in BWRs are erosion–corrosion, low-cycle fatigue, and high-cycle fatigue. The degradation sites, ranked in order of importance, are listed in Table 10.4.

There have been no fatigue analyses on most of the BWR feedwater and main steam line systems and the fatigue analyses that were done as part of the design of the Class 1 sections did not consider a number of important stressors (stratified flow, water hammers, etc.) and used ASME design curves, which are probably inappropriate (room temperature air data). In addition, erosion–corrosion damage has not been adequately accounted for in the design and inservice inspection of the BWR feedwater and main steam line systems, and the phenomena and extent of degradation caused by mechanical and flow-induced vibrations are neither well-understood nor sufficiently defined (in terms of plant parameters and cycles) to quantitatively predict feedwater system lifetimes. Therefore, it is possible that a dynamic event such as an earthquake or a water hammer might promote piping failure in these systems without a leak-before-break scenario.

The conclusions and recommendations related to the aging of BWR feedwater and main steam line systems are as follows:

1. Erosion–corrosion is a major degradation mechanism in carbon steel feedwater and main steam line piping, and may lead to catastrophic failure. Erosion–corrosion damage can be very localized. Reliable nondestructive inspection methods are being developed that effectively cover 100% of the area under investigation and consistently detect the minimum wall thicknesses. The results of thickness measurements should be evaluated considering the highest possible transient pressure. A pipe section significantly weakened by erosion–corrosion may fail catastrophically if subjected to a water hammer or a pressure pulse.

2. The feedwater piping is subject to fatigue damage caused by stratified flows, thermal shocks, flow-induced vibrations, and equipment vibrations. Under normal operation, this fatigue damage would ultimately lead to leakage of the feedwater. However, a pipe section significantly weakened by a fatigue crack may rupture if subjected to a water hammer or a high-pressure pulse. The use of on-line fatigue monitoring to assess low-

Table 10.4. Summary of degradation processes for BWR feedwater and main steam systems

Rank	Potential Degradation Sites	Stressors	Degradation Mechanisms	Failure Modes	ISI Methods
1	Feedwater piping near fittings and at geometric discontinuities	Coolant chemistry, temperature, and flow rate; stratified flows; water hammers, vibration	Erosion–corrosion; fatigue; erosion	Rupture; leaks; cracks; large deformations	Volumetric and surface examination at welds; wall-thickness measurements
2	Main steam piping near fittings and at discontinuities	Coolant chemistry, temperature, and flow rate; moisture content in steam; steam hammers, temperature gradients; vibration	Erosion–corrosion; fatigue	Rupture; leaks; cracks; large deformations	Volumetric and surface examination at welds; wall-thickness measurements

cycle fatigue damage is recommended.[a] Use of acoustic emission monitoring to detect any crack growth in the feedwater nozzle and horizontal portions of the piping, including both base metal and welds, should be evaluated. Further development of this technique for crack growth may be needed. Acoustic emission already has been developed as a leak detection method.

3. General Electric experiments show that low-cycle fatigue cracks are initiated in carbon steel piping in a BWR environment at far fewer cycles than would be predicted using the in-air test data that forms the basis for the ASME design curve. Therefore, environmental fatigue data need to be developed for assessing fatigue damage to feedwater and main steam line piping.

4. Piping systems are subject to high-cycle fatigue damage caused by thermal striping, and flow- and equipment-induced vibrations. Criteria are needed for assessing high-cycle fatigue damage to carbon steel piping in a BWR environment and for developing acceptable limits for such damage.

5. Hydrogen water chemistry (HWC) reduces the oxygen level in the feedwater, and therefore it is likely to decrease the fatigue crack growth rates in the carbon steel piping. However, the use of HWC may increase the rate of erosion-corrosion in the feedwater and main steam line if the oxygen level is not maintained above about 20 ppb. It is recommended that for at least one BWR plant, a baseline inspection of the piping wall thickness be performed before implementing HWC, and periodic inspections be done thereafter to identify any changes in the erosion-corrosion rates.

6. Use of an on-line monitoring method to determine erosion-corrosion damage (for example, isotope implantation) needs to be evaluated because there is significant uncertainty regarding erosion-corrosion rates. Also, thickness measurements from various plants should be used to assess the current wall thinning models and revise (as needed) the guidelines that identify the sites that are susceptible to erosion-corrosion.

7. Monitoring of oxygen content is needed so that fatigue-crack-growth rates and erosion-corrosion rates can be better estimated. Higher oxygen levels lead to higher fatigue-crack-growth rates, but lower erosion-corrosion rates.

8. Use of flame-sprayed stainless steel coatings has been successful in eliminating erosion-corrosion damage in carbon steel pipes containing wet steam in the Swedish BWRs. Use of this coating to reduce erosion-corrosion damage in feedwater piping needs to be evaluated.

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a. Temperature, pressure, and vibration of piping need to be monitored so transient thermal and mechanical loads caused by different stressors can be determined and the fatigue damage estimated. The stressors include heatups, cooldowns, operational transients, water hammers, steam hammers, stratified flows, and flow-induced and equipment vibrations.

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56. ANSI/ASME Standard OM–3 Rev. 1 (Pending), "Preoperational and Initial Startup Vibration Testing of Nuclear Power Plant Piping Systems."

11. BOILING WATER REACTOR CONTROL ROD DRIVE MECHANISMS AND REACTOR INTERNALS

A. G. Ware

The control rod drive mechanisms (CRDMs) are located at the bottom of boiling water reactor (BWR) pressure vessels and they position the neutron absorbing control rod assemblies (CRAs) within the reactor core to provide reactivity control during startup and shutdown of the reactor, flux shaping at power, and emergency shutdown (scram). Each CRDM is linked to its CRA by a disconnectable coupling. A CRA can be withdrawn or inserted by its CRDM or held at a desired location. The control rods, drive housings, and guide tubes are shown with other BWR reactor internals in Figure 11.1.

The external housing of the CRDM forms a portion of the reactor coolant pressure boundary, but is not subject to the same thermal or mechanical loadings that pose major degradation problems for other portions of the BWR pressure boundary, such as the reactor pressure vessel (RPV). The probable mode of CRDM failure is not catastrophic failure of the housing, but rather a malfunction of one of the numerous small subcomponents, resulting in functional failure of the entire mechanism such as a stuck rod, or a small leak. Such failures could lead to reactivity–initiated accidents, anticipated transients without scram (ATWS), or small–break loss–of–coolant accidents (LOCAs). The basic BWR CRDM has changed little over the years. The two major differences between the BWR/3 and BWR/6 designs are that in the BWR/6 (1) the hydraulic pressure used to scram the CRAs is greater and (2) the stub tube between the CRDM housing and the RPV (see Figure 11.2) has been eliminated. Some stub tube–to–reactor vessel welds have experienced stress corrosion cracking. The aging problem associated with the use of stub tubes is discussed later in the chapter. A few changes in materials have also been made. Note from Table 11.1 that most of the older BWRs, on which plant license renewal decisions will initially have to be made, are BWR/3s or BWR/4s.

The reactor internals support the core, maintain fuel assembly alignment, limit fuel assembly movement, direct the flow of reactor coolant within the RPV, and separate steam from water. Major components (listed from bottom to top) are the core plate assembly, fuel supports, jet pump assemblies, core shroud, top guide, core spray lines and spargers, feedwater spargers, shroud head, and steam separator and dryer assemblies. The reactor internals subcomponents described in this chapter do not include the CRAs, nor the fuel assemblies, which are replaced relatively often.

There should be no major shifts in the alignment of the reactor internals because such shifts could prevent proper insertion of CRAs. Degradation of internals could introduce loose parts within the core, resulting in reactivity accidents or damage to the recirculation pumps. Loose parts could also cause impact damage to other components or block the flow in some coolant channels.

11.1 Description[1,2,3]

The external (pressure housing and support) and various internal functional parts of the CRDM, and the principles of operation, are described in this section. The individual reactor internals subcomponents are then discussed, followed by a description of the materials used for the CRDMs and the reactor internals.

11.1.1 CRDMs. There are two major differences between pressurized water reactor (PWR) and BWR CRDMs. First, the PWR CRDMs are electrical–mechanical devices, whereas the BWR CRDMs are mechanical–hydraulic devices. The second difference is that PWR CRDMs are mounted on the top of the RPV, whereas BWR CRDMs are mounted at the bottom. The bottom–mounted BWR drives do not interfere with refueling and are operative even when the head is removed from the RPV. Also, the separation of the steam and water in the upper plenum of a BWR is more easily accomplished because there is no interference from top–mounted control rods. Additionally, a large fraction of the volume in the upper part of a BWR core is filled with steam, which significantly reduces the power in this area. If the CRAs entered from the top of the RPV, they would over–depress the neutron flux in the upper part of the core. Finally, The CRDMs are somewhat more accessible for inspection and servicing from below the vessel. This location also provides maximum use of the reactor water as a shield for reducing the neutron exposure of the drive components. However, BWR CRDMs cannot be scrammed by gravity, but must rely on a fluid pressure differential for full insertion.

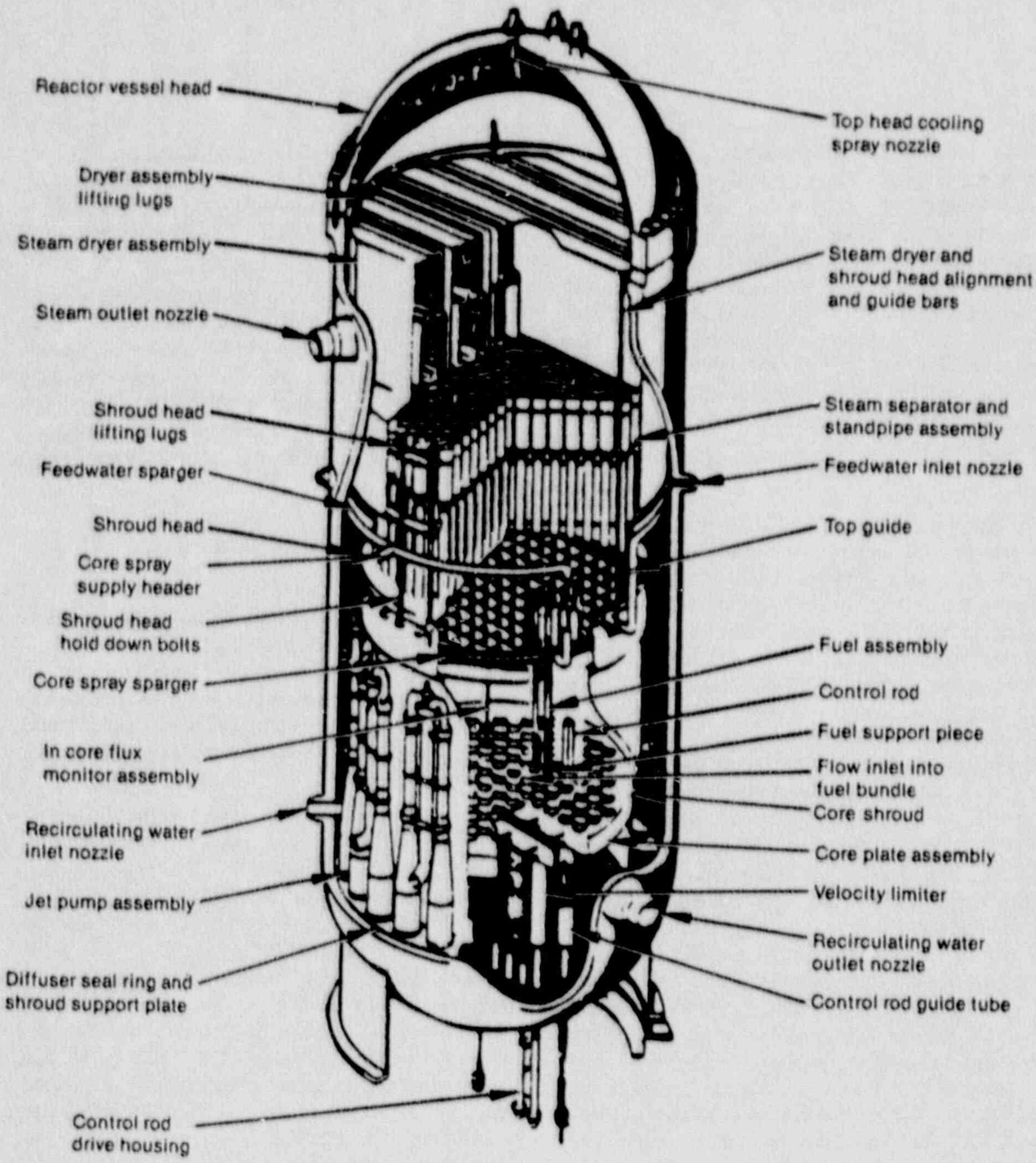

Figure 11.1. Arrangement of CRDM and reactor internals used in BWR/3 and BWR/4 designs.

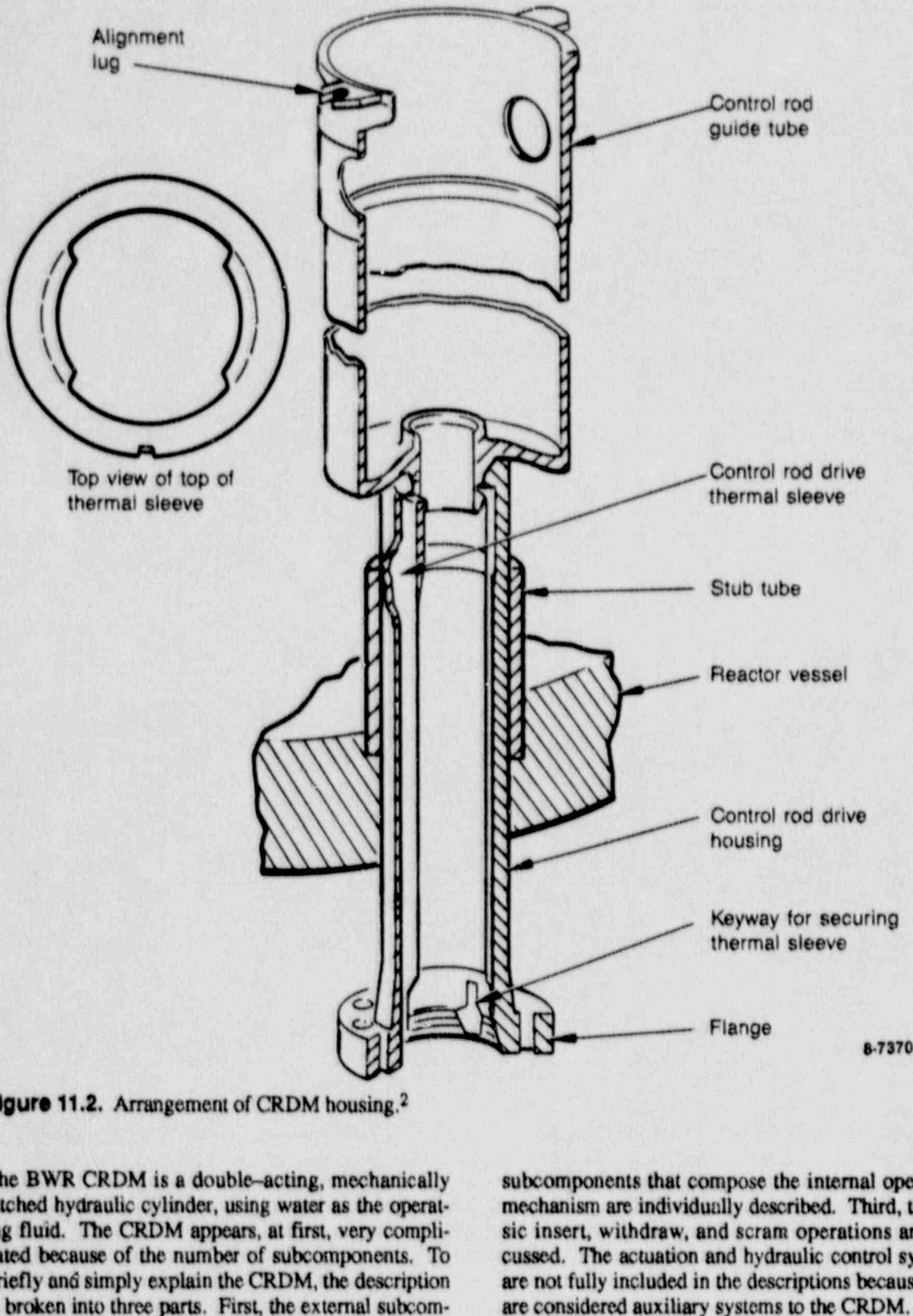

Figure 11.2. Arrangement of CRDM housing.[2]

The BWR CRDM is a double-acting, mechanically latched hydraulic cylinder, using water as the operating fluid. The CRDM appears, at first, very complicated because of the number of subcomponents. To briefly and simply explain the CRDM, the description is broken into three parts. First, the external subcomponents that house and surround the operating mechanism are described. Second, the more important subcomponents that compose the internal operating mechanism are individually described. Third, the basic insert, withdraw, and scram operations are discussed. The actuation and hydraulic control systems are not fully included in the descriptions because they are considered auxiliary systems to the CRDM. Typical materials of construction are listed with those of the reactor internals in Section 11.2.3.

Table 11.1. BWR plant designations

Plant	BWR Designation	Construction Permit (year)	Operating License (year)
Big Rock Point	1	1960	1962
Oyster Creek 1	2	1964	1969
Nine Mile Point 1	2	1965	1969
Dresden 2,3	3	1966	1969, 1971
Millstone 1	3	1966	1970
Monticello	3	1967	1970
Pilgrim 1	3	1968	1972
Quad Cities 1,2	3	1967	1971, 1972
Browns Ferry 1,2	4	1967	1973, 1974
Browns Ferry 3	4	1968	1976
Brunswick 1,2	4	1970	1976, 1974
Cooper	4	1968	1974
Duane Arnold	4	1970	1974
Fermi 2	4	1972	1985
FitzPatrick	4	1970	1974
Hatch 1,2	4	1969, 1972	1974, 1978
Hope Creek 1	4	1974	1986
Limerick 1	4	1974	1984
Peach Bottom 2,3	4	1968	1973, 1974
Shoreham	4	1973	1985
Susquehanna 1,2	4	1973	1982, 1984
Vermont Yankee	4	1967	1973
LaSalle 1,2	5	1973	1982, 1983
Nine Mile Point 2	5	1974	1986
WNP 2	5	1973	1983
Clinton 1	6	1976	1987
Grand Gulf 1	6	1974	1982
Perry 1	6	1977	1986
River Bend 1	6	1977	1985

Description of External Subcomponents. The lower part of the CRDM is bolted to a flange on the CRDM housing, and the upper part (drive piston) is connected to the CRA through a coupling assembly. The weight of the fuel is supported by orificed fuel supports, which in turn are supported by the control rod guide tubes. From there, the weight is transferred through the housing and stub tubes to the bottom head of the RPV. The housing, its support, and the CRDM-to-CRA coupling are described in this section.

The CRDM housing forms part of the primary pressure boundary between the reactor and the containment. One type of overall arrangement is shown in Figure 11.2. Until about 1974, stub tubes were welded to the RPV bottom head during vessel fabrication, prior to the final stress relief of the vessel. Stress reliefs were conducted at about 620°C (1150°F) and required a number of hours because of the mass of the material. This treatment produced gross sensitization of the stub tubes. The CRDM housings were subsequently field–welded to the top of the stub tubes. They were not welded at the bottom, to allow for thermal expansion downward. After about 1974, the housings were welded directly to the bottom head without the intervening stub tube.

The stub tubes were made of sections of wrought stainless steel pipe until about 1966 or 1967; thereafter (until their elimination in about 1974), they were made of Alloy 600. A thermal sleeve (see Figure 11.2) is installed inside the housing to protect the housing–to–stub tube welds from thermal overstress during CRDM operation, such as when hot water is forced out of the CRDM during insertion and scram (discussed below). The sleeve is held in place by a bayonet–type lock that is rotated into position to form the joint (see inset of Figure 11.2), where a small amount of leakage takes place. The CRA guide tube (top of Figure 11.2) is placed on the housing and is locked into place by the same type of bayonet fit. The bottom of the housing is closed with a flange, to which the position indicator housing is bolted. The CRDM itself is also bolted to this flange. The pressure housing is designed and analyzed to conform to the requirements of the American Society of Mechanical Engineers Boiler & Pressure Vessel Code (ASME Code), Section III.[4]

Underneath the housing is a support to prevent ejection of a CRA from the reactor core in the event a housing should fail. In the case of a housing failure, the CRA movement is stopped by the support once it has travelled a short distance.

Description of Internal Subcomponents. The overall arrangement of the CRDM itself is shown in Figure 11.3. Figure 11.4 shows the openings in the flange face, Figure 11.5 the collet assembly, and Figure 11.6 shows the insert mode of CRDM operation. To relate the CRDM internal subcomponents to the external subcomponents described above, note that the internals are bounded on the bottom by the position indicator housing, on the sides by the CRDM housing, and on the top by the CRA and guide tube. A description of the CRDM components, beginning with the index tube/drive piston assembly on the upper end and proceeding to the flange on the lower end, will be covered next.

The index tube is a long hollow shaft made of nitrided stainless steel (see Figures 11.5 and 11.6). Circumferential locking grooves, spaced every 152 mm (6 in.) along the outer surface, transmit the weight of the control rod to the collet assembly (described below), which is a locking mechanism that surrounds the index tube as shown in Figures 11.5 and 11.6. The function of the index tube is similar to that of a piston rod in a conventional hydraulic cylinder. It is threaded into the drive piston at the lower end, and the drive piston/index tube assembly composes the main moving subcomponent of the CRDM.

The collet assembly (see Figures 11.5 and 11.6) serves as the index tube locking mechanism. The assembly prevents the index tube from moving down. Locking is accomplished by fingers that engage the locking groove in the index tube. The collet piston is normally held in position by a force of approximately 667 N (150 lb) supplied by a spring. The collet assembly will not unlatch until the collet fingers are unloaded by a drive–in signal. A pressure approximately 1.2 to 1.8 MPa (180 to 260 psi) (depending on the particular design) above reactor pressure must then be applied to the collet piston to overcome the spring force, slide the collet up against the conical surface in the guide cap, spreading the fingers out so they do not engage the locking groove in the index tube.

The drive piston is threaded to the lower end of the index tube, and operates between positive end stops, with a hydraulic cushion only at the upper end. The piston has both inside and outside seal rings and operates in an annular space between the piston tube and inner cylinder. The seal rings are made of Graphitar–16, and the sealing force is provided by Alloy X–750 C–springs. Because the type of inner seal used is effective in only one direction, the lower sets of seal rings are mounted with one set sealing in each direction.

Movement of the piston assembly is accomplished by differential hydraulic pressures (explained below). The effective piston area is approximately 774 mm^2 (1.2 $in.^2$) for downtravel (CRA withdrawal) and 2645 mm^2 (4.1 $in.^2$) for uptravel (CRA insertion). This difference in driving area tends to balance the CRA weight and ensures a higher force for insertion than for withdrawal.

The piston tube is a cylinder, or column, extending upward inside the drive piston and index tube (see Figure 11.6). The piston tube is fixed to the bottom flange of the CRDM and remains stationary. Water is brought to or expelled from the upper side of the drive piston through this tube. A series of orifices at the top of the tube provides progressive water shutoff to cushion the drive piston at the end of its scram stroke. A stationary piston, called the stop piston, is mounted on the upper end of the piston tube. This piston provides the seal between the normal operating pressure of the reactor coolant and the space above the drive piston. It also functions as a positive end stop at the upper limit of CRA travel.

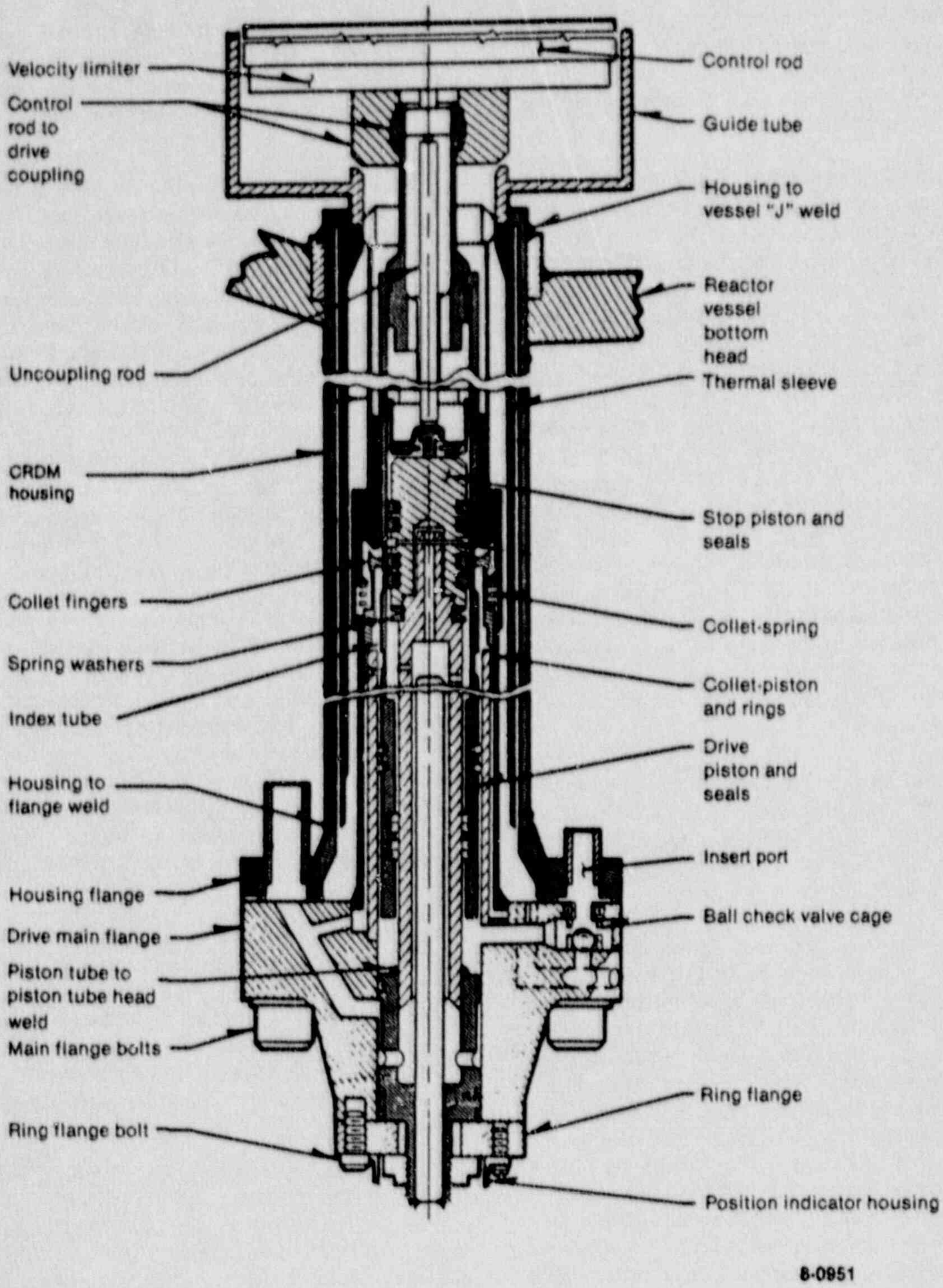

Figure 11.3. CRDM internal subcomponents.[1]

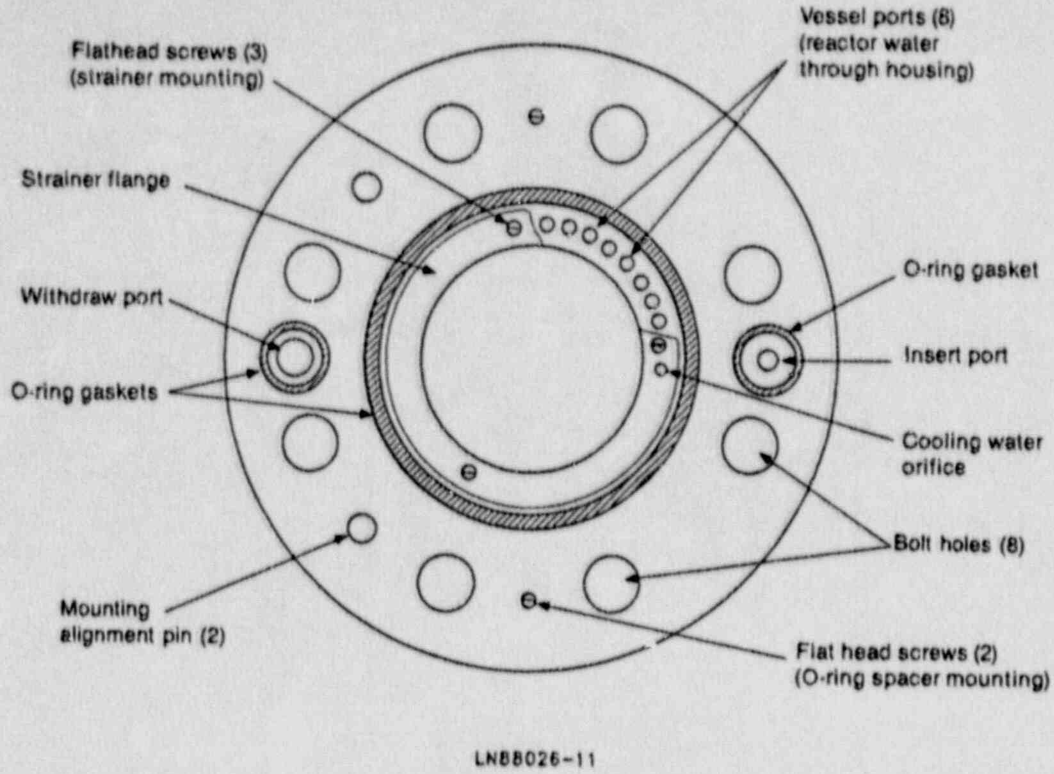

Figure 11.4. CRDM housing flange, showing insert and withdraw ports.[3]

The main flange and cylinder assembly (inner and outer cylinders welded to the flange) are bolted to the CRDM housing flange with eight equally spaced bolts. Three teflon–coated stainless steel O–rings (around the insert port, around the withdrawal port, and around the circumference of the outer cylinder) provide a pressure–tight seal. Figure 11.4 shows the openings in the flange face and the O–rings that prevent leakage of primary coolant to the containment. The inner and outer cylinders form an annulus through which pressure may be applied to the collet piston. The inside surface of the inner cylinder is honed to provide a smooth surface for the drive piston outer seals. Reactor coolant fills the annulus between the outer cylinder and the housing.

Porting in the main flange directs water from the withdraw port to the upper side of the drive piston and to the under side of the collet piston, and from the insert port to the lower side of the drive piston and to the CRDM cooling water channel between the thermal sleeve and the outer cylinder. Eight ports direct reactor water to the under side of the drive piston through a ball check valve, which serves as a two–way check valve to direct either reactor water or drive water for control rod insertion. Because the drive water is normally at a pressure greater than reactor pressure, the ball check valve is normally in the closed position. Directional control valves (DCVs) 120 through 123 control flow through the drive water and exhaust headers.

Insertion. CRDM operation during the insert mode shown in Figure 11.6 is as follows:

a. When a rod–insertion signal is received, DCV 123 opens and drive water from the drive water header enters the CRDM through the insert line and passes through the insert port in the flange. Since the drive water is at 1.2 to 1.8 MPa (180 to 260 psi) higher pressure than the reactor pressure, the ball check valve remains closed. The drive water flows upward between the piston tube and inner cylinder to act on the bottom of the drive piston, forcing it upward. Remember that the top of the drive piston is attached to the bottom of the index tube, which is in turn attached to the CRA.

b. Exhaust water flows from above the drive piston, up along the area between the index tube and the piston tube, through holes in the piston tube, down the inside of the piston

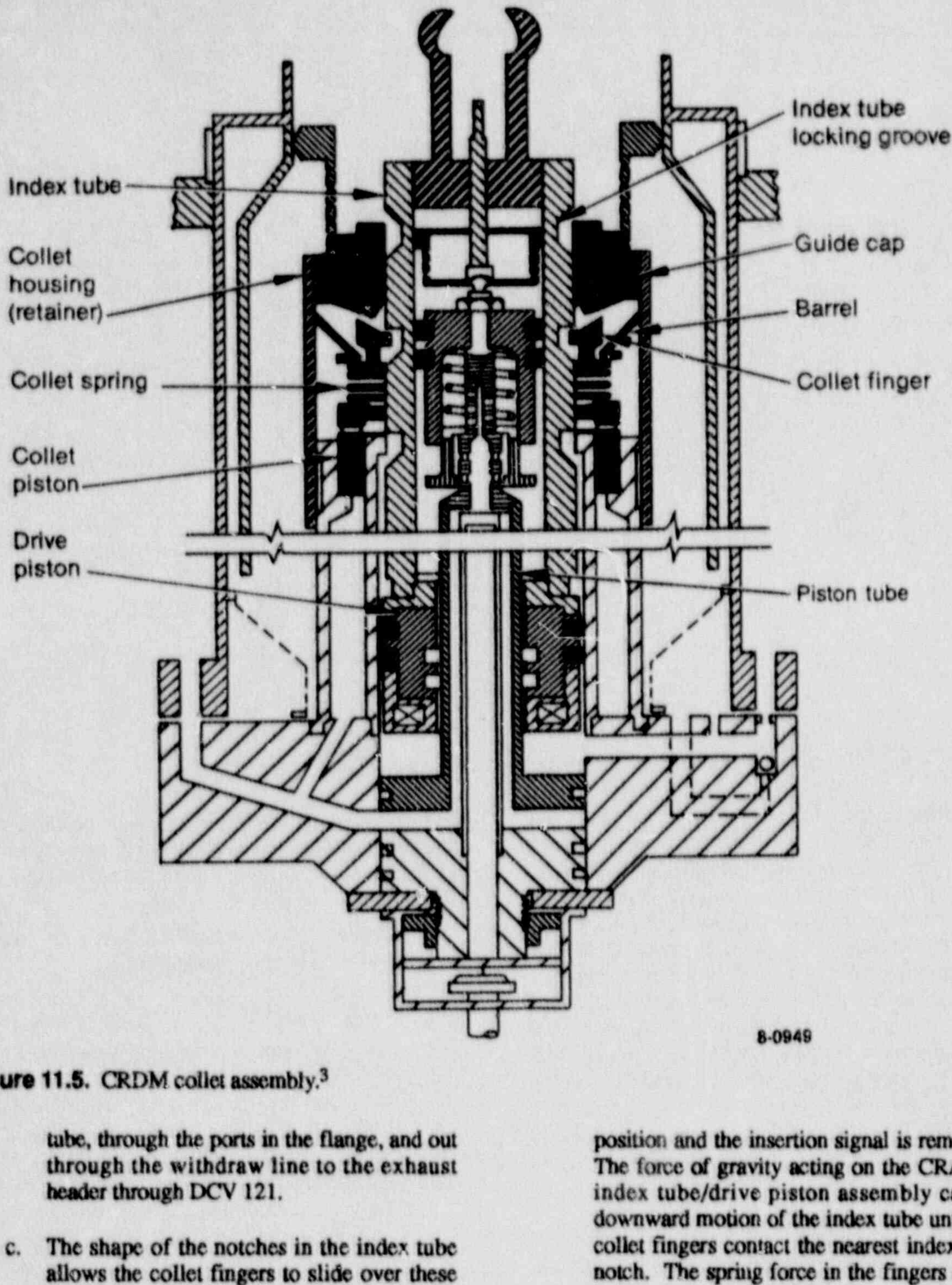

Figure 11.5. CRDM collet assembly.[3]

tube, through the ports in the flange, and out through the withdraw line to the exhaust header through DCV 121.

c. The shape of the notches in the index tube allows the collet fingers to slide over these notches without resisting movement in the upward direction. However, when rod motion ceases, the rod is not latched to prevent withdrawal, because the collet fingers are not lined up with the index tube notches.

Latching is accomplished by letting the rod settle, as follows. The CRDM is inserted slightly further than the desired notch position and the insertion signal is removed. The force of gravity acting on the CRA and index tube/drive piston assembly causes downward motion of the index tube until the collet fingers contact the nearest index tube notch. The spring force in the fingers move them into the notch, latching the assembly. As the insertion signal is removed, DCV 123 closes and DCV 120 opens, allowing water to flow from below the drive piston, down between the piston tube and inner cylinder, and out the insert line to the exhaust header.

d. When the CRDM is stationary, cooling water originating from the condenser hotwell reject

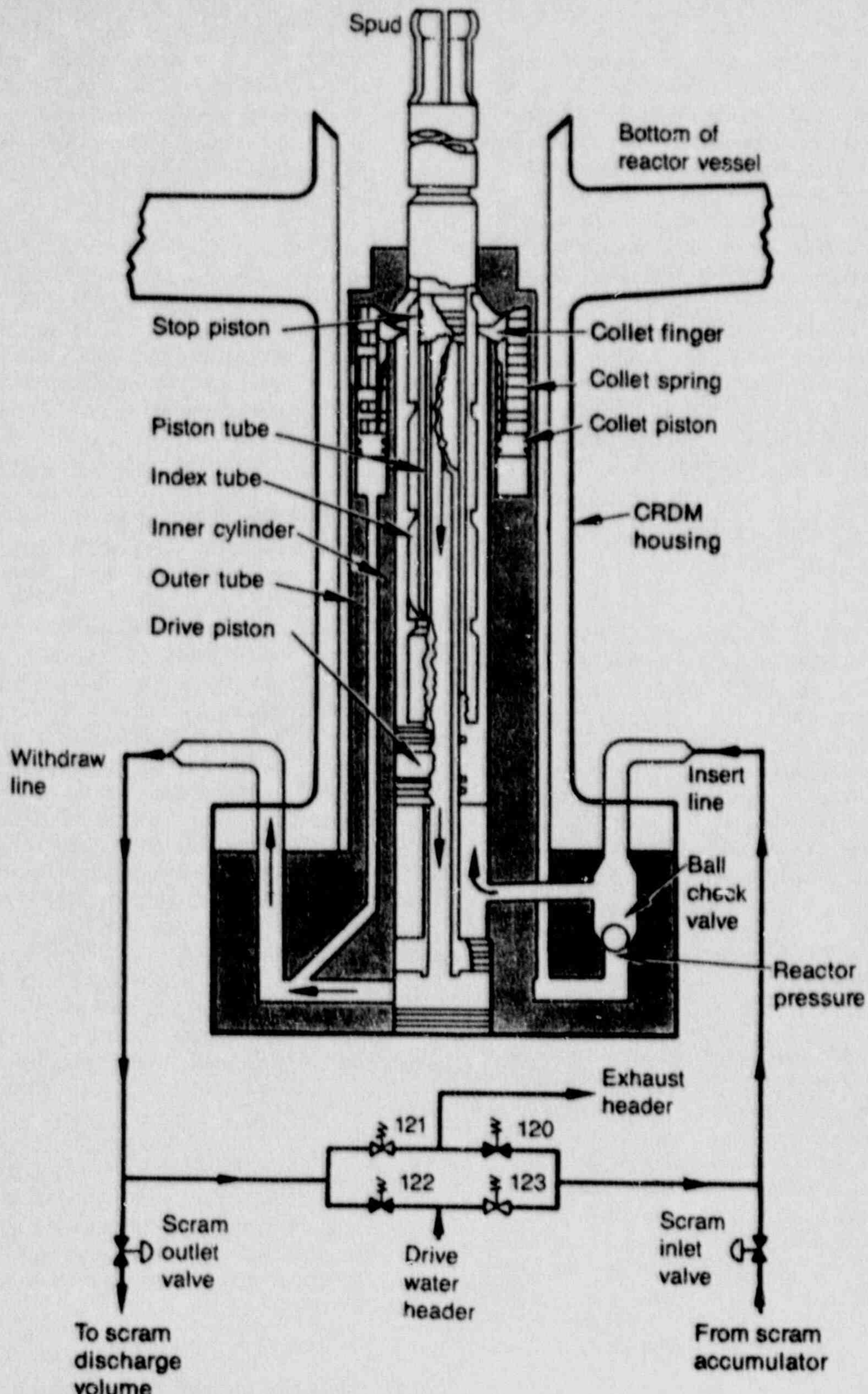

Figure 11.6. CRDM operation, insert mode.[2]

line or the condensate storage tank passes through the insert port to cool the CRDM. A cooling water orifice adjacent to the insert port permits cooling water to flow and protect the seals and bushings on the drive piston and the stop piston (see Figures 11.3 and 11.5), which are made of Graphitar-14, a material that would become brittle if exposed to BWR temperatures of 285°C (545°F). Seal degradation can prevent CRDM motion. The cooling water should maintain CRDM temperatures below 120°C (250°F). Normal cooling water pressure is 0.1 MPa (20 psi) greater than reactor pressure; the typical flow for each CRDM is 2×10^{-5} m^3/s (0.31 gpm); and discharge is into the RPV.

Withdrawal. CRDM operation during the withdraw mode shown in Figure 11.7 is as follows:

a. The weight of the control rod blade and the index tube/drive piston assembly is approximately 125 N (280 lb) and the tops of the notches on the index tube are square. Therefore, the friction between the index tube notch and the collet fingers is too great to allow a pressure force from the collet piston to remove the fingers from the square notches. So, initially an insertion signal is applied for a short time (0.5 s), which causes the rod to insert 51 to 76 mm (2 to 3 in.). As the rod inserts, the collet fingers slide out over the tapered bottom of the notch in the index tube.

b. After the insertion signal is removed, a withdrawal signal is applied. This opens DCV 122 and the withdraw port in the flange, supplying drive pressure through the withdraw line. The higher-pressure drive water flows between the inner and outer cylinders and acts against the bottom of the collet piston. The collet piston moves upward against the force of the collet spring, forcing the collet fingers into the recessed portion of the guide cap, thereby holding the collet fingers out of the way for the rod withdrawal.

c. The flow through the withdraw port branches so that a portion of the incoming fluid also travels up the inside of the piston tube, through the holes at the top of the piston tube, and down the outside of the piston tube to the top of the drive piston, forcing it downward. The exhaust water flows from beneath the drive piston, down the annulus between the piston and inner cylinder, through the insert line, and out the insert line through DCV 120.

d. The withdrawal signal is terminated shortly before the CRA reaches the desired position. This removes the pressure from the collet piston, allowing it to return to its normal position by the means of the force supplied by the collet spring. As the rod settles, the collet fingers engage the next notch in the index tube, as described above.

Scram. Figure 11.8 illustrates the fluid-flow path for CRDM operation in the scram mode. On a scram signal, the scram inlet valve aligns a charged accumulator, maintained at approximately 10 MPa (1500 psi), to the insert line. At the same time, the scram outlet valve shown at the bottom left of Figure 11.8 aligns the withdraw line to the scram discharge volume, which is initially at atmospheric pressure. All DCVs remain closed. The flow path within the CRDM internals is identical to that of the insertion mode. However, because of the higher differential pressure, scram insertion is much faster than normal insertion. The ball, or two-way, check valve directs either the reactor vessel pressure or the driving pressure, whichever is greater, to the underside of the drive piston. (Normally, the drive water pressure would initially be higher, and the reactor vessel coolant is a backup when no accumulator pressure is available.) Upon a scram, the accumulator provides the initial pressure to insert the control rod, but as accumulator pressure drops below reactor pressure, the ball check valve opens and reactor pressure completes the drive's forward stroke. The CRDMs normally operate at a steady-state temperature of about 120°C (250°F), because of the continuous flow of cooling water. However, when the ball check valve opens and reactor pressure is used to push the piston, hot 285°C (545°F) reactor coolant is suddenly drawn around the outside of the collet housing, as shown in Figure 11.8, imposing a severe thermal shock on the CRDM internals.

11.2.2 Reactor Internals. The reactor internals in a BWR not only comprise the core support structure as in a PWR, but also include the feedwater spargers (which spray incoming feedwater into the RPV), the jet pump assemblies (which increase flow through the core), and the steam separator and dryer assemblies

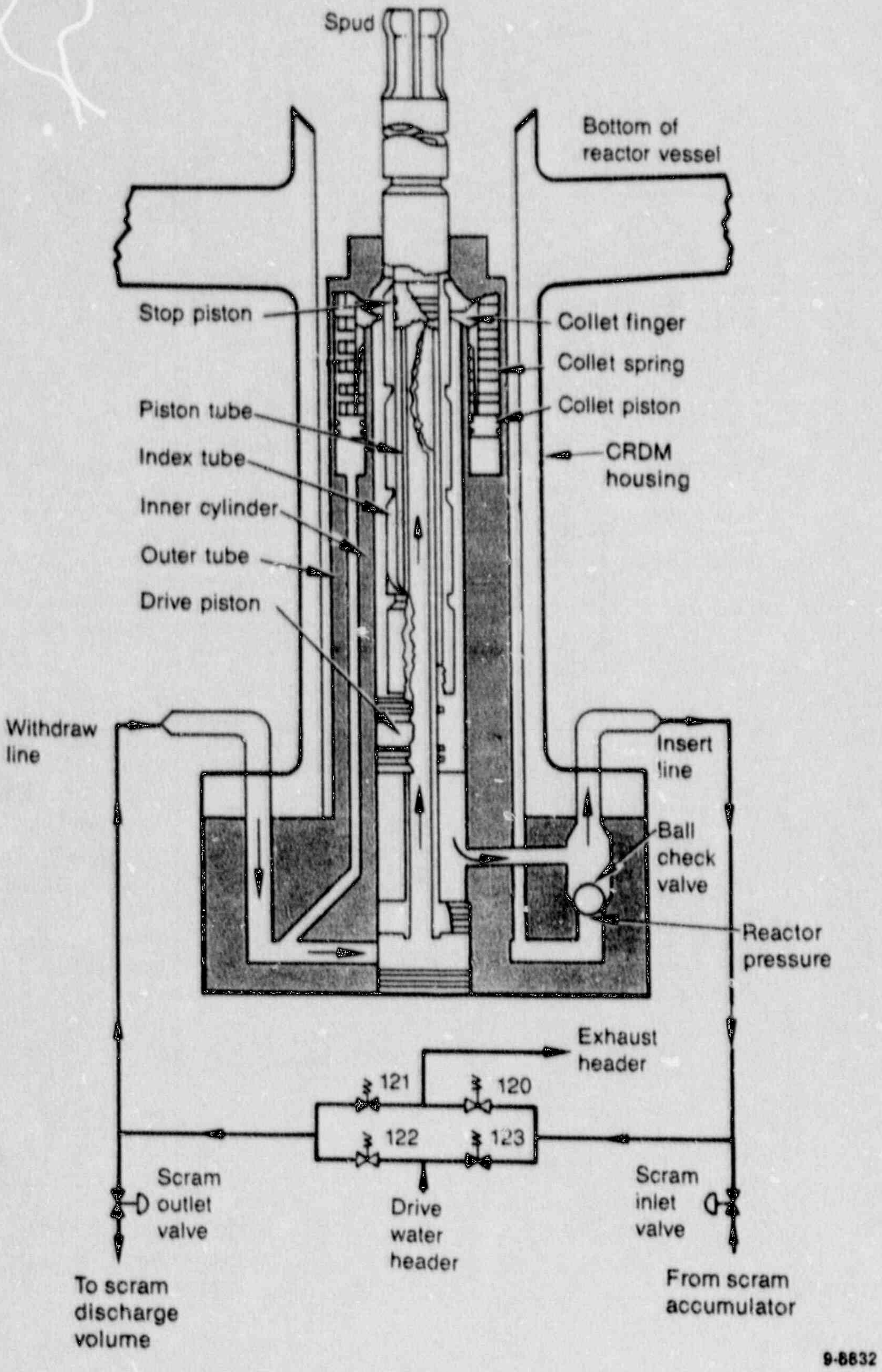

Figure 11.7. CRDM operation, withdrawal mode.[2]

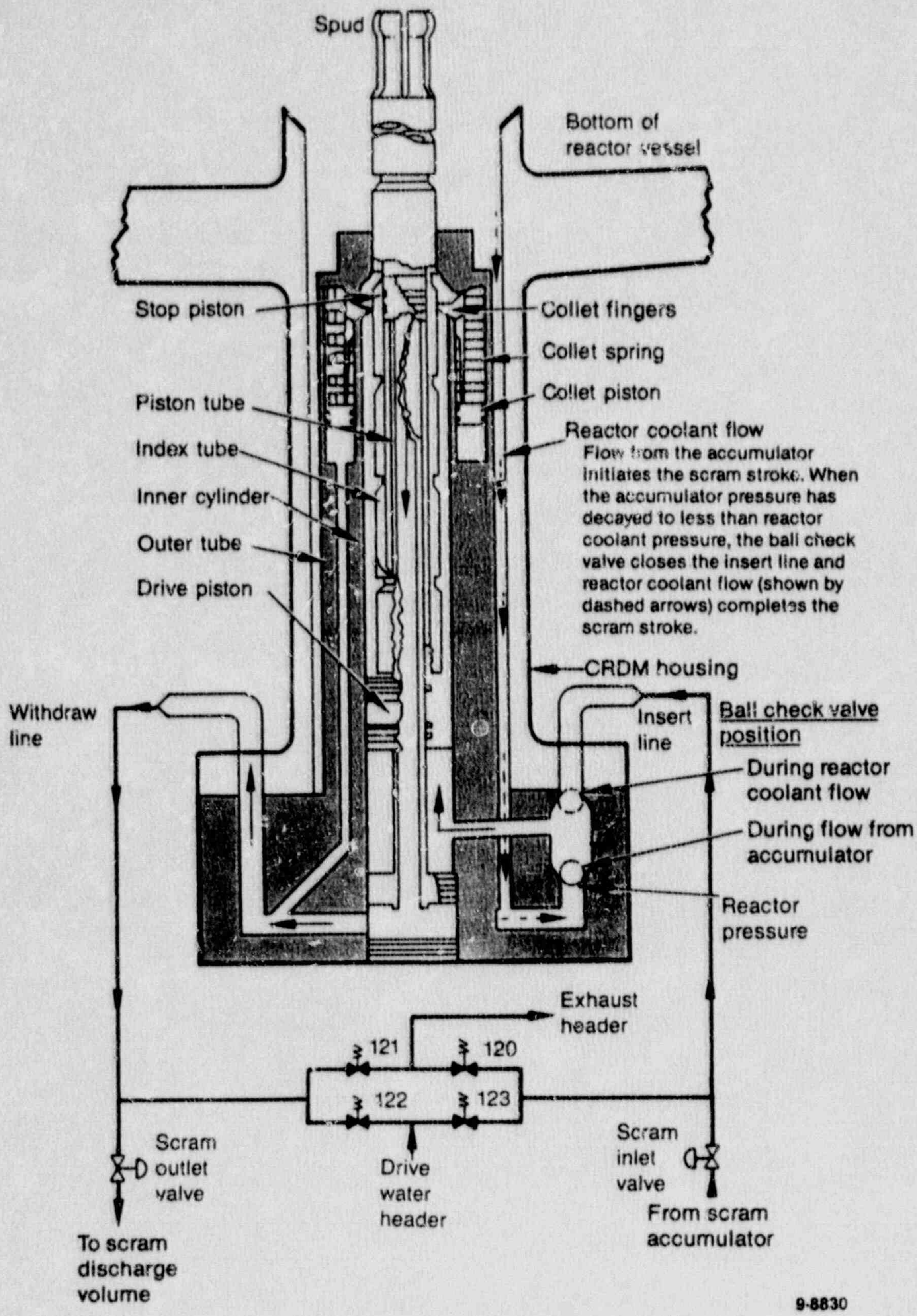

Figure 11.8. CRDM operation, scram mode.[2]

(which increase the quality[a] of the steam after it exits the core). The important reactor internals assemblies are described in this section.

Core Shroud and Core Plate. The core shroud (shown in Figure 11.9) is a 51-mm- (2-in.-) thick cylindrical stainless steel assembly that provides vertical and lateral support for the core plate, top guide, and shroud head. It also provides vertical support for all peripheral fuel assemblies, transferring their weight to the RPV bottom head. The lower end of the core shroud is welded to the core support cylinder.

The core plate assembly (shown in Figure 11.10) is a circular, horizontal stainless steel plate with vertical stiffener plate members underneath. Tie rods serve to cross-brace the stiffener members. The core plate supports the peripheral fuel bundles, both vertically and laterally, by means of their fuel support pieces. It also laterally supports all fuel support pieces and fuel bundles. The core plate assembly is bolted to a support ledge in the bottom area of the core shroud. Alignment pins on the core plate engage slots in the shroud to correctly position the core plate before it is secured.

Shroud Baffle Plate. The shroud baffle plate (see Figure 11.10) is welded to the RPV wall and is supported underneath by column members welded to the vessel bottom head. This Alloy 600 plate also is a mounting surface for the jet pump diffusers and it supports the weight of the core shroud, the core plate assembly, some fuel assemblies, the top guide, the core spray spargers, and the shroud head/steam separator assembly. The plate contains two access holes, 180 degrees apart, that were used during construction and subsequently closed by welding Alloy 600 cover plates over the openings.

Fuel Supports. The standard fuel support pieces are four-lobe Grade CF-8 stainless steel castings that support four fuel assemblies each, and contain orifices to ensure proper coolant flow distribution to the individual fuel assemblies (see Figure 11.11). These pieces rest on top of the control rod guide tubes and are aligned with the same alignment pins used by the guide tubes. They provide lateral alignment for the bottom end of four fuel assemblies, and transmit the weight of the fuel assemblies to the control rod guide tubes.

The Types 304 and 304L stainless steel peripheral fuel support pieces are located at the outer edge of the core and are used to support fuel assemblies not located adjacent to control rods. Each peripheral support piece supports one fuel assembly. These pieces are welded to the core plate and are not removable. (The peripheral fuel support pieces are also illustrated in Figure 11.11.)

Jet Pump Assemblies. The jet pumps (see Figure 11.12) provide forced flow through the core to yield a higher reactor power than would be possible with natural circulation. Jet pumps were introduced with the BWR/3 design. The 20 jet pumps are located in two semicircular groups with two jet pumps and a common inlet header forming an assembly. A thermal sleeve is welded into the recirculating water inlet nozzle to reduce the stresses in the nozzle wall caused by differences in temperatures between the inlet water and RPV wall, and between the inlet water and nozzle wall. The thermal sleeve is welded to an inlet riser used to lower the nozzle elevation level below the active fuel region to reduce fast neutron flux exposure to the nozzle welds. Restrainers (riser brace arms) provide lateral support for the upper end of the risers and yet allow for the vertical differential expansion between the riser and RPV during heatup and cooldown. The upper end of each BWR/5 and BWR/6 jet pump is a nozzle assembly that includes five small nozzles cast together, whereas each BWR/3 and BWR/4 jet pump has a single nozzle.

The jet pump diffusers are welded to adapters that are first welded to the shroud support (baffle) plate. The jet pump is primarily composed of forged Type 304 stainless steel. Exceptions are the inlet transition piece casting, the wedge casting, and the diffuser collar casting (Grades CF-3 and CF-8 stainless steel). The diffuser is made by welding a stainless steel forged ring to a forged Alloy 600 ring. The inlet mixer contains a pin, insert, and holddown beam made of Alloy X-750.

Top Guide. The top guide is set on a rim near the top end of the core shroud and is bolted into place. It is formed by a series of Type 304 stainless steel plates joined at right angles by means of vertical slots (no welds) to form a matrix of square openings (see Figure 11.13). The beams are welded to a peripheral ring. Each central opening accomodates four fuel assemblies and one control rod. Along the periphery are smaller openings that accommodate the peripheral fuel assemblies. Cutouts on the bottom edge of the top guide at the junction of the cross plates support the top end of the neutron instrument assemblies and neutron source holders. The top guide provides lateral support for the upper end of all fuel assemblies, neutron monitoring instruments, and the installed neutron sources.

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a. The quality $x = \dfrac{v - vf}{vg - vf}$, where v, vf, and vg are the specific volumes of the steam, liquid, and saturated vapor states, respectively, for a given pressure.

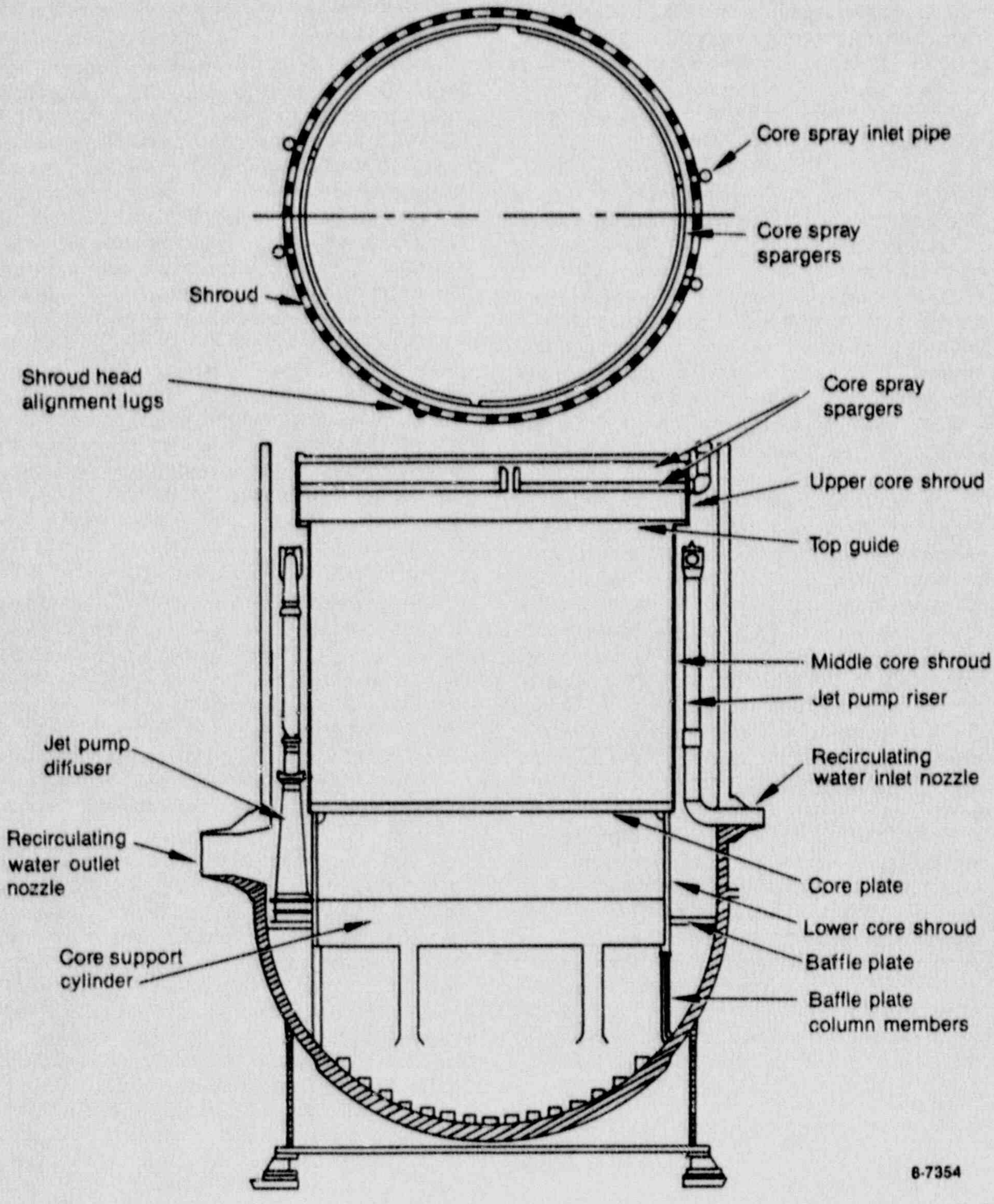

Figure 11.9. Core shroud.[2]

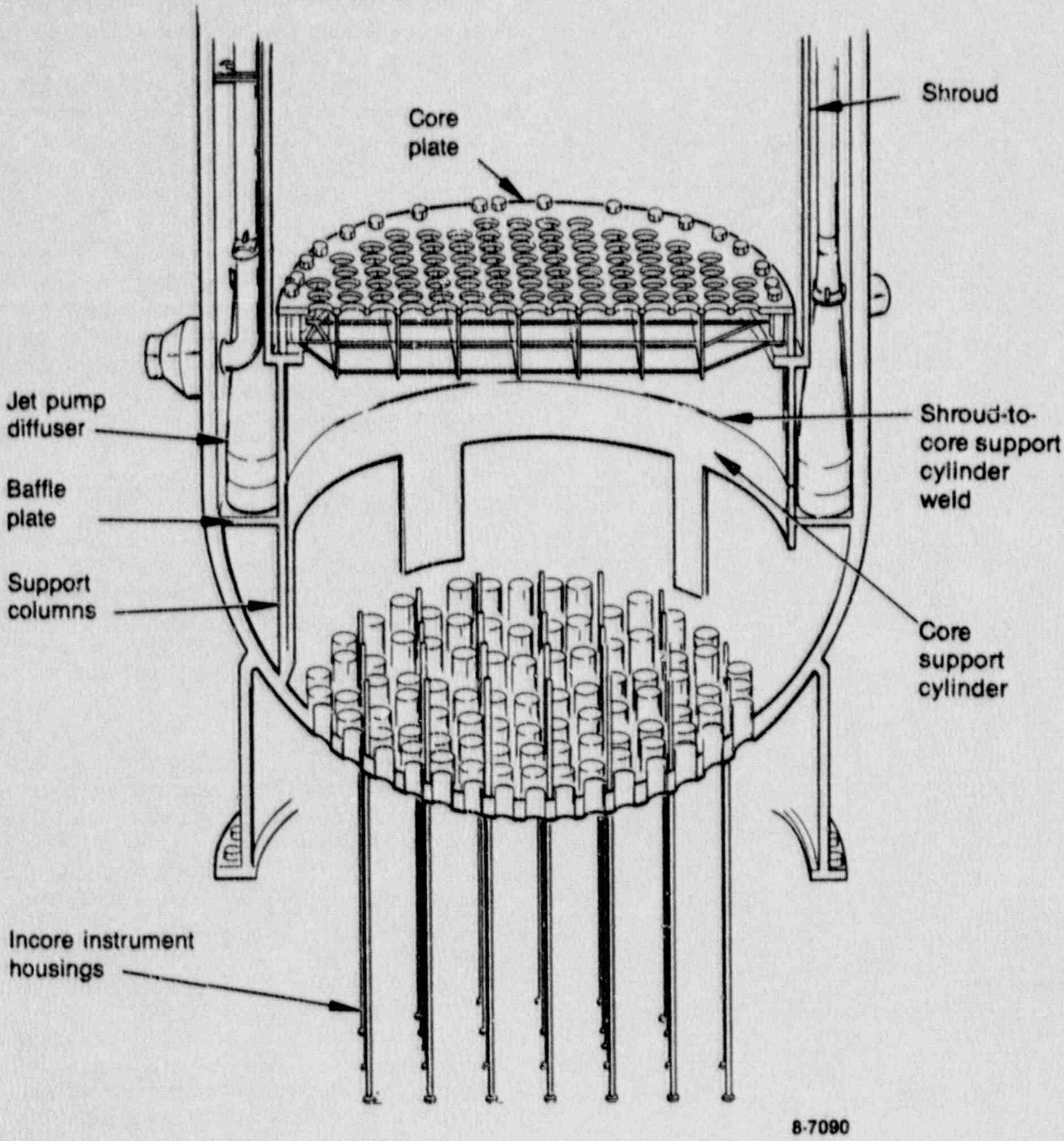

Figure 11.10. RPV lower plenum region components.[2]

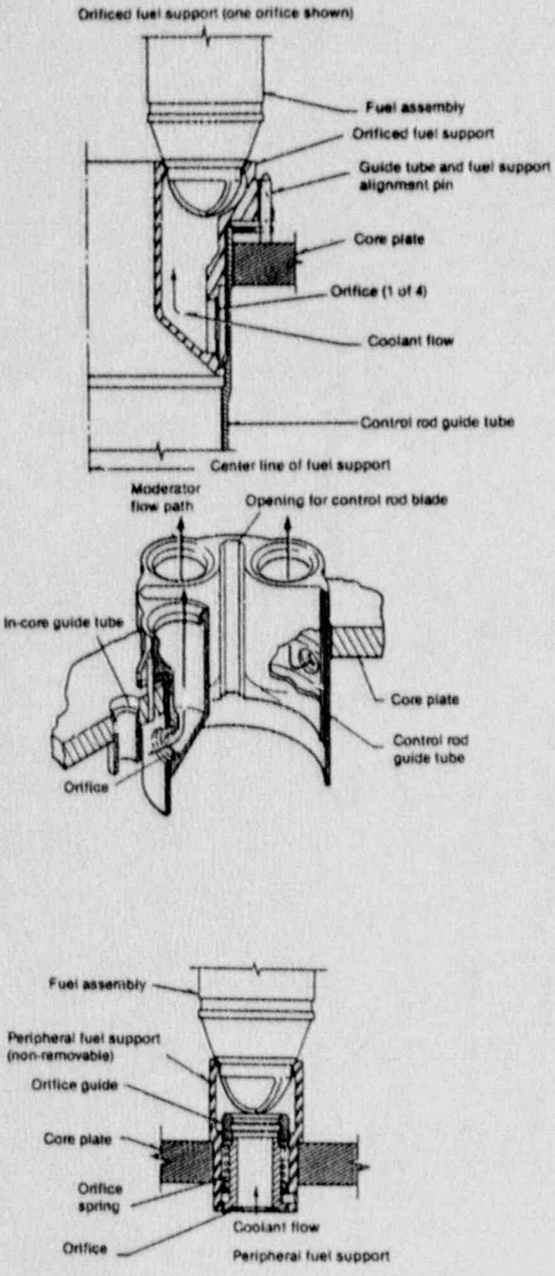

Figure 11.11. Fuel support pieces.[2]

Core Spray Lines and Spargers. The design of the emergency core cooling system (ECCS) depends on the vintage of the plant. In all cases, there is a high-pressure and a low-pressure ECCS. In the BWR/2 through BWR/4 plants, the high-pressure ECCS is delivered to the vessel annulus through the feedwater lines. However, in BWR/5 and BWR/6 plants it is delivered through a spray ring (sparger) inside the core shroud. In one of the low-pressure ECCS systems, the core spray is delivered inside the core shroud by two spray rings in the BWR/2 through BWR/4 plants, and through one spray ring in the BWR/5 and BWR/6 plants (see Figure 11.9). Each spray ring contains two 180-degree, Type 304 stainless steel spargers. The core spray lines (supply headers) are supported by clamps attached to the vessel wall, and by brackets inside the core shroud. Spray nozzles connect to the spray spargers.

Shroud Head. The Type 304 stainless steel shroud head closes off the core outlet so that all the liquid moderator and steam is forced through the steam separators. It consists of a flange and dome onto which is welded an array of standpipes, with a steam separator located at the top of each standpipe, as shown in Figure 11.14.

The shroud head/steam separator assembly is bolted to the top of the upper shroud by 24 to 36 bolts per plant (see Figure 11.1 and Figure 11.14, Detail A). These bolt assemblies consist of a 305-mm- (12-in.-) long Alloy 600 stud threaded into the shroud, a stainless steel nut threaded onto the Alloy 600 stud, and a tensioning bolt attached to both the nut and stud.

Feedwater Spargers. The reactor is supplied with feedwater by means of four (several older BWRs) or six Type 304 stainless steel feedwater spargers (Figure 11.15) that are supported by brackets attached to the RPV wall. Each sparger consists of a thermal sleeve, distribution header, and converging discharge nozzles. The thermal sleeve (made of Type 304 stainless steel or Alloy 600) is intended to protect the hot feedwater nozzle surface from coming in contact with the cold feedwater, thus minimizing the potential for thermal fatigue damage in the safe end or the safe-end-to-feedwater piping welds. The converging discharge nozzles are welded to the top of the distribution headers to ensure that the thermal sleeves and distribution headers remain full of water during all modes of reactor operation.

The feedwater enters through the thermal sleeves, the distribution headers, and then the converging discharge nozzles, which direct the feedwater from the distribution header radially inward into the downcomer. The relatively cool feedwater [about 216°C (420°F)] in the downcomer annulus region subcools the water flowing to the recirculation pumps and jet pumps to ensure adequate net positive suction head to these pumps, so that they will not be damaged by cavitation.

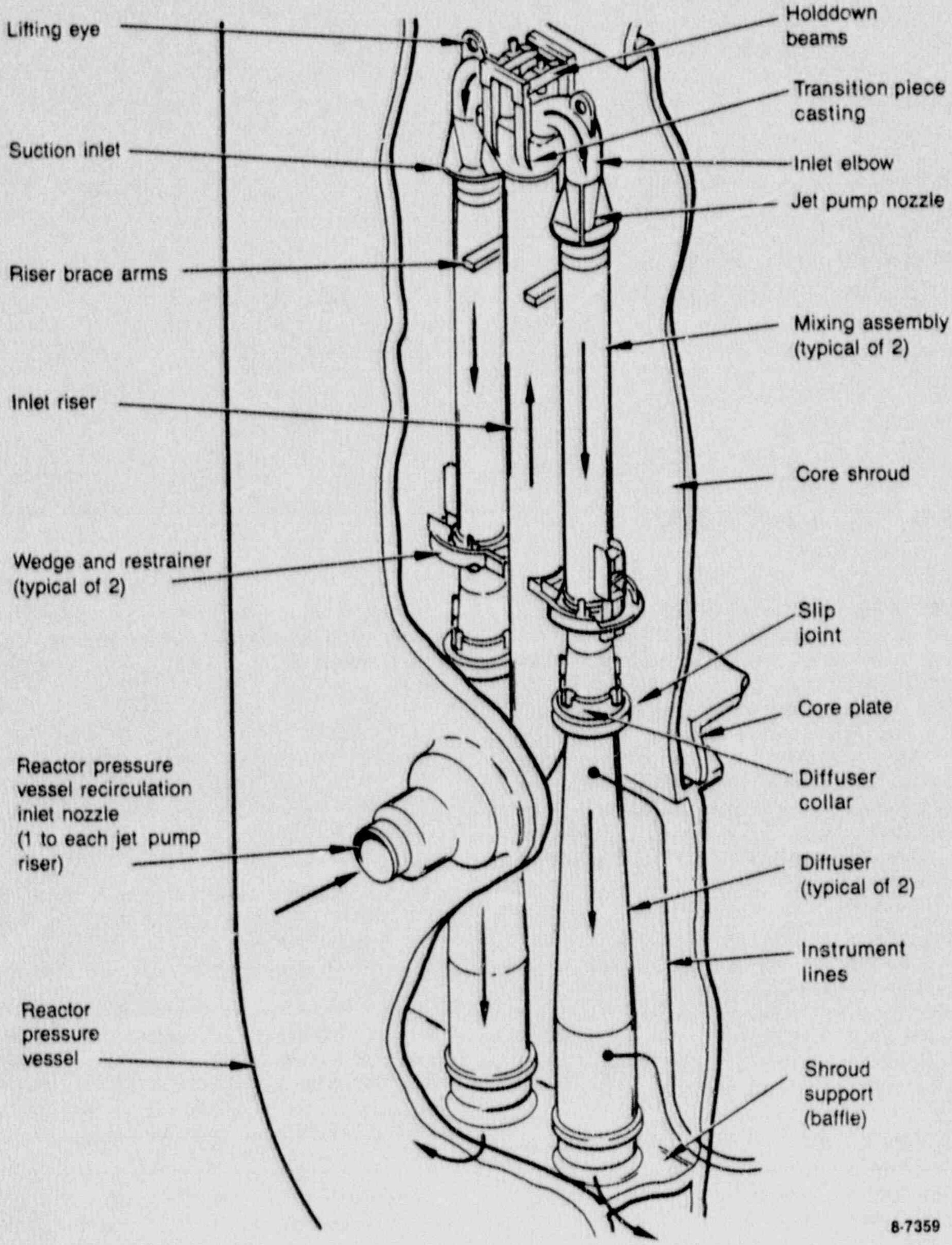

Figure 11.12. Jet pump assembly.[2]

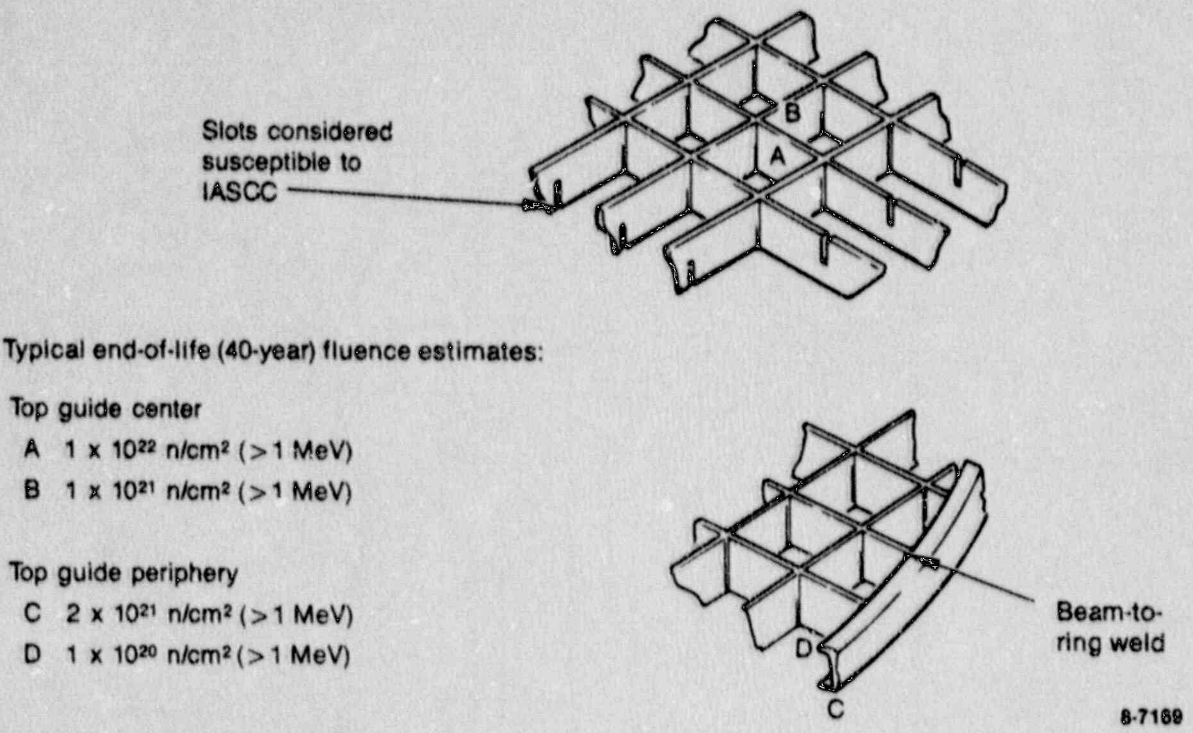

Figure 11.13. Top guide structure.[9]

Steam Separator and Dryer Assemblies. The steam separator assembly (made of Types 304 and CF-8 stainless steel) increases the quality of the steam from 10 to 90% as it travels between the core exit and the steam dryers. The separator assembly consists of 261 cyclone-type separator assemblies, each consisting of a 254-mm- (10-in.-) diameter steam separator welded to the top of a 150-mm (6-in.-) diameter standpipe (see Figure 11.16). The standpipes are welded to the shroud head, as discussed above. The separators are cross-braced to form a rigid structure to prevent vibration.

The steam dryers (see Figure 11.17) are fabricated into a one-piece assembly with no moving parts and increase the steam quality to greater than 99.9%. The assembly is properly aligned by vertical guide rods that are attached to brackets welded to the RPV wall. Upward movement is restricted by hold-down brackets attached to the RPV top head.

11.2.3 Materials. The BWR CRDMs and reactor internals are primarily made of stainless steel. Typical CRDM component materials are listed in Table 11.2. These are mainly forged Type 304 stainless steel, but some components, such as parts of the CRA guide tube, are made of Grade CF-3 and CF-8 cast stainless steel.

Two special processes are employed that subject selected Type 304 stainless steel parts to temperatures in the sensitization range:

1. The inner cylinder and spacer in the inner cylinder, outer cylinder, and flange assembly and the retainer in the collet assembly are hard-surfaced with Colmonoy 6 (a nickel-based alloy).

2. The collet piston and guide cap (in the collet assembly) are nitrided to provide wear-resistant surfaces.

Colmonoy hard-surfaced components have been used for the past 10 to 15 years in CRDMs. Nitrided components have been used in CRDMs since 1967. It is normal practice to remove some CRDMs at each refueling, and visually examine Colmonoy hard-surfaced parts and nitrided surfaces for wear.

A stainless steel (SA-336, Cl F8) safe end on the CRDM hydraulic system return is attached to a carbon steel (SA-508 Cl 2) nozzle on the reactor pressure vessel. The weld is buttered with stainless steel.[5]

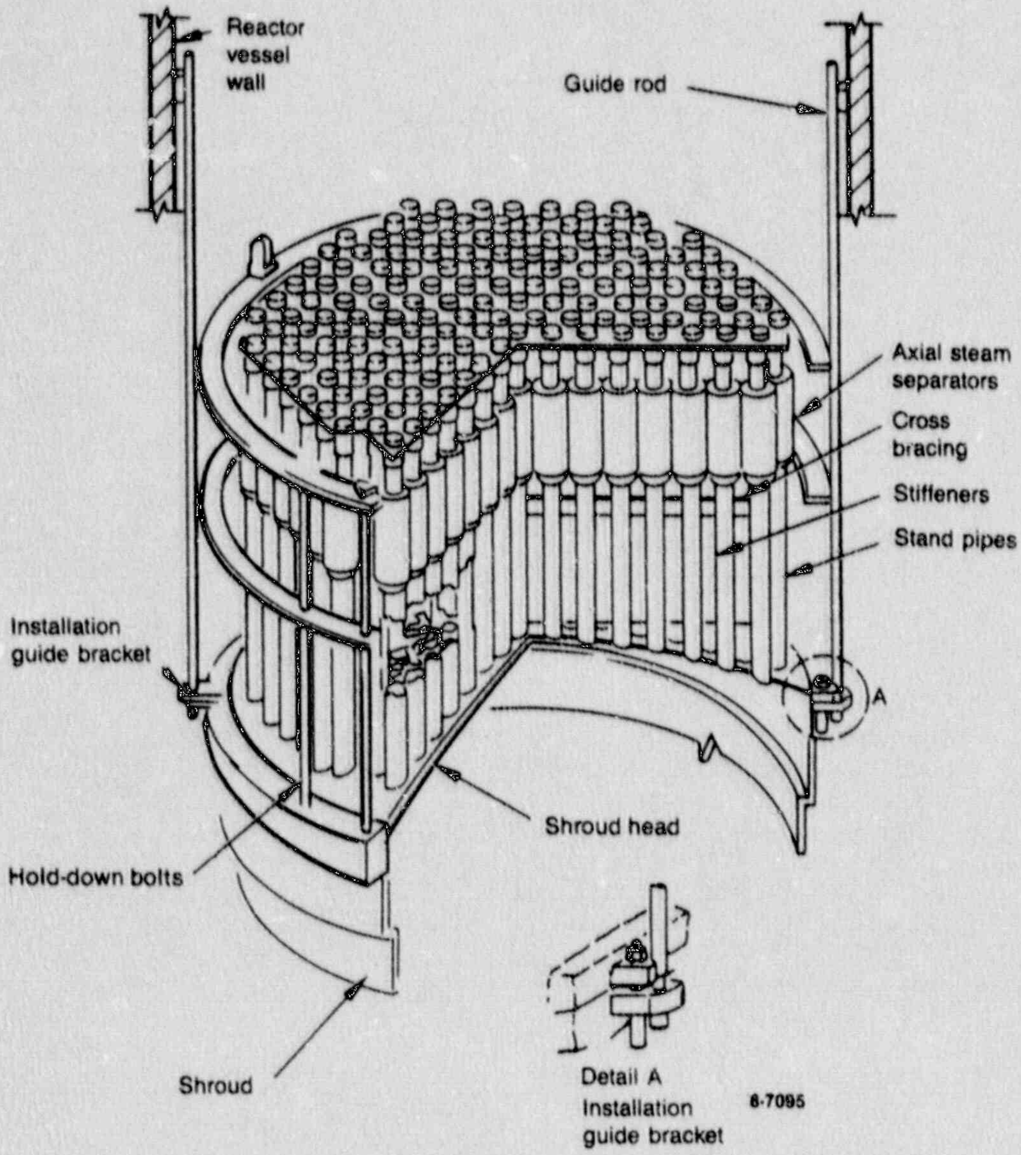

Figure 11.14. Shroud head.[2]

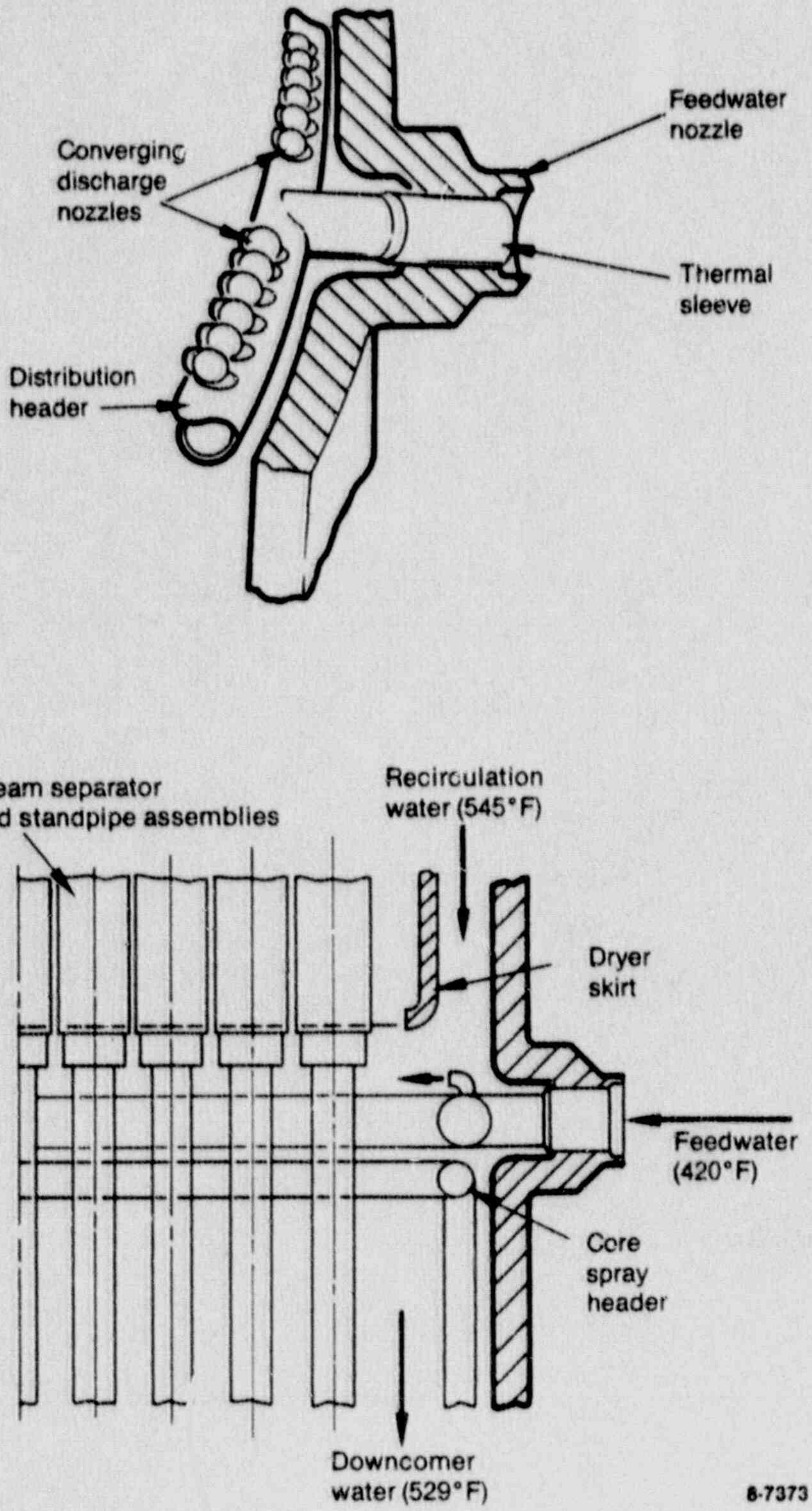

Figure 11.15. Feedwater spargers.[2]

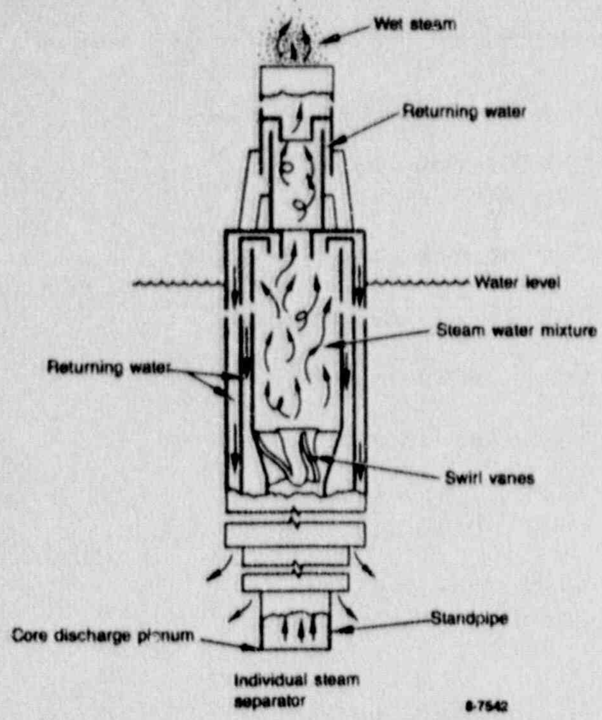

Figure 11.16. Steam separator assembly.[2]

The diaphragms in the air operators of the solenoid-operated valves (such as the scram outlet valve in Figure 11.6) are included in Table 11.2 because they have a limited shelf life. The diaphragm is made of BUNA-N rubber and nylon material.

The reactor internals materials are listed in Table 11.3 and are either stainless steel or a Ni-Cr-Fe alloy. The core plate and top guide studs, nuts, wedges, and pins are made of Type 304 stainless steel, Type XM-19 stainless steel, and ASTM A193 (Gr. B8A) and ASTM A194 (Gr. 8A) high-alloy steel bolting material. Some castings (Types CF-3 and CF-8 stainless steel) are used. The jet pump holddown beams are made of Alloy X-750.

11.3 Stressors

Although both CRDMs and reactor internals are subject to thermal cycles and a corrosive environment, the stressors for each are somewhat different and are discussed individually below.

11.3.1 CRDMs. The main stressors causing component degradation for the CRDM are the high-temperature corrosive environment; the thermal transients caused by plant heatups, cooldowns, and

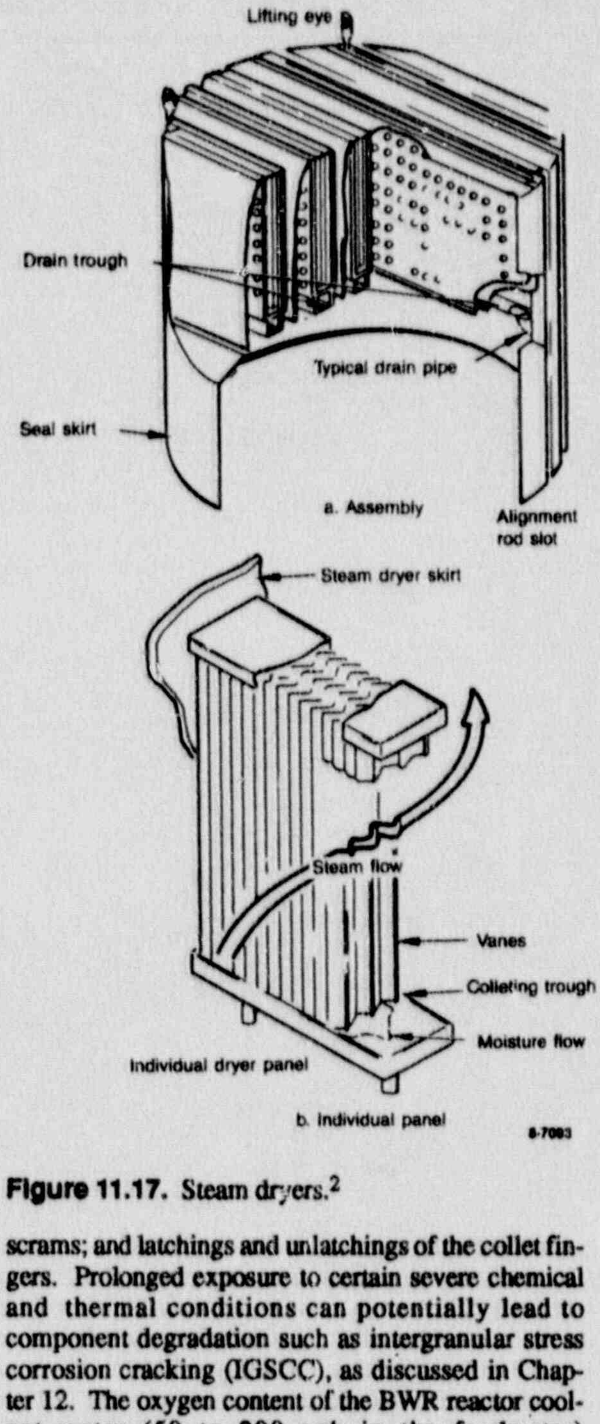

Figure 11.17. Steam dryers.[2]

scrams; and latchings and unlatchings of the collet fingers. Prolonged exposure to certain severe chemical and thermal conditions can potentially lead to component degradation such as intergranular stress corrosion cracking (IGSCC), as discussed in Chapter 12. The oxygen content of the BWR reactor coolant water (50 to 200 ppb in the feedwater) is considerably higher than that of PWRs, thereby increasing the corrosion potential for CRDM components. Therefore, hydrogen water chemistry has been recommended because it specifically reduces the oxygen content of the BWR reactor coolant.[6] Some BWRs are located near the ocean, but no provision was made to prevent the ingress of salt air during construction, which proved to be a highly corrosive stressor.

Table 11.2. Materials used in control rod drive mechanisms

Component	Material
Stub tube	Type 304 stainless steel or Alloy 600
Housing	Type 304 stainless steel
CRA Guide Tube	Types CF-8 and 304 stainless steel
Flange and plugs	Grade F304 stainless steel
Cylinder and outer tube	Type 304 stainless steel
Piston tube	ASME SA-249 or SA-479, Grade XM-19 stainless steel
Index tube	ASME SA-479 or SA-249 Grade XM-19 stainless steel, 17-4 PH
Collet piston	Type 304 stainless steel
Collet fingers; coupling spud; collet spring	Alloy X-750
Drive and stop piston seals and bushings	Graphitar-14
Piston seal C-springs	Alloy X-750
Piston rings	Haynes 25
Ball check valve	Haynes stellite
Elastomeric O-ring seals	Ethylene propylene
Drive piston head	17-4 PH
O-rings	Teflon-coated, Type 304 stainless steel
Diaphragms in valve air operators	BUNA-N rubber; nylon

Plant heatups and cooldowns can cause fatigue damage to the materials of construction, as has been discussed in Sections 3.2 and 5.2 of Volume 1. The expected transients during a typical BWR 40-year lifetime are listed in Table 11.4.[1] The most severe transients from a fatigue standpoint are the scram and the heatup/cooldown cycle. Most of the CRDM is cooled by <120°C (< 250°F) external cooling water to ensure the life of the Graphitar-14 seals and bushings, which become brittle when exposed to high temperatures over long periods. However, reactor water at 285°C (545°F) is suddenly drawn through the CRDM around the outside of the collet housing [originally at less than 120°C (250°F)] during a

Table 11.3. Materials of reactor internals

Component	Material
Shroud support (baffle plate)	Alloy 600
Baffle plate access hole covers	Alloy 600
Core support cylinder	Alloy 600
Jet pump assembly	Types 304, 304L, and 316L stainless steel; Alloy 600 (forgings); Grades CF-8 and CF-3 stainless steel (castings)
Jet pump holddown beams	Alloy X-750
Fuel assembly bolts and fingers	Ni-Cr-Fe, Alloy A-286
Peripheral fuel supports	Type 304 and 304L stainless steel
Orificed fuel supports	Grade CF-8 stainless steel
Top guide pins	Type XM-19 stainless steel
Core spray spargers	Type 304 stainless steel
Shroud head holddown bolts	Type 304 stainless steel and Alloy 600
Shroud, core plate and top guide	Type 304L stainless steel
Feedwater spargers and thermal sleeves	Type 304 stainless steel or Alloy 600
Steam separator and steam dryer beams	Alloy A-286
Steam separator and steam dryer assembly	Type 304 stainless steel (forgings); Grade CF-8 stainless steel (castings)

scram.[7] Temperatures and pressures during a normal plant heatup/cooldown cycle range from ambient temperature and atmospheric pressure to hot operating conditions [core inlet temperature of 278°C (533°F)] at full plant pressure [the nominal core design pressure is 7.238 MPa (1035 psig)].

The latchings and unlatchings of the collet fingers and the index tube can cause mechanical wear over time. Debris from wear and corrosion products or from other types of component degradation (such as metal chips) can lodge in the internal mechanisms and cause improper operation. Misalignment of internal subcomponents can cause wear and sticking. Also, improper installation and maintenance can increase the probability of failure, because of the complicated operation of the CRDM and its numerous small subcomponents with tolerances critical to proper functioning.

11.3.2 Reactor Internals. The most significant life-limiting stressors for the reactor internals subcomponents include the high-temperature corrosive coolant, prolonged exposure to high neutron fluxes, the thermal transients that occur during plant heatups and cooldowns, high preload stresses in the bolts and studs, and flow-induced vibrations. The lower reactor internals are subjected to the same reactor coolant chemical environment as the CRDMs. However, in the upper reactor internals region, there is a two-phase (water and steam) mixture, and the chemistry of the coolant is not as well-known.

Table 11.4. Typical BWR CRDM design transients

Transient	Design Events for 40-Year Lifetime
Reactor startup/shutdown	120
Vessel pressure tests	130
Vessel overpressure tests	10
Interruption of feedwater flow	80
Scrams	300
Operating-basis earthquake	10
Safe shutdown earthquake	1
Scram with inoperative buffer[a]	10
Jog cycles	30000

a. Without the buffer to cushion the stop of the CRDM at the conclusion of the scram stroke, the impact force will be greater than with the normal scram. Loss of piston seals could make the buffer inoperative.

There is a clear correlation between the coolant conductivity in a BWR and the propensity for IGSCC initiation in certain creviced reactor internals components, for example, Alloy 600 shroud-head bolts, stainless steel intermediate and source range monitor dry tubes, and stainless steel safe end welds.[6] Significant reductions in crack-growth rates were found with low conductivities (<0.3 μS/cm) and with low electrochemical potential (ECP), such as achieved with hydrogen addition to the feedwater, that is, hydrogen water chemistry.

Since the reactor internals are in close proximity to the fuel, they must endure very high cumulative neutron fluences. Those components nearest the core, such as the shroud and top guide, are particularly susceptible to irradiation-assisted stress corrosion cracking (IASCC). Estimates of measured and calculated fluences for various BWR internals locations are listed in Table 11.5 for 40 years of operation (100% full power, 100% of the time).[8] Other estimates of peak fluence levels for the top-guide structure after approximately 40 years of operation are on the order of 1×10^{22} n/cm^2 (>1 MeV). Using 1×10^{22} n/cm^2 (>1 MeV) as the 40-year fluence at the bottom-center of the top guide, typical estimated fluence levels at other top-guide locations are shown in Figure 11.13.[9]

Laboratory tests have shown that high stresses, crevices, and high fluence levels accelerate IASCC. Reference 10 reports a threshold for IASCC of 5×10^{21} n/cm^2 (>1 MeV). It is not necessary that the material be initially sensitized to be susceptible to IASCC. Other laboratory tests have shown that Types 316NG, 316L, and 304 stainless steel specimens irradiated to 2.5×10^{20} n/cm^2 (>1 MeV) experience IGSCC, though the IGSCC was much less severe when the oxygen content of the water was reduced from 32 to 0.2 ppm.[10] Stainless steels also experience irradiation embrittlement and a loss of toughness when irradiated above 1×10^{21} n/cm^2 (>1 MeV).

11.4 Degradation Sites

The major BWR CRDM operational problems have been associated with the reliability of the hydraulic valves. Another degradation site of concern is the pressure housing and the stub tubes.[5] The pressure housings are susceptible to fatigue from the thermal and pressure cycles. The stub tube-to-pressure vessel welds are particularly susceptible to IGSCC. Collet housings have cracked from thermal fatigue. The CRDM internal components such as the index tube and collet assembly, valves, springs, etc., experience mechanical wear, and degradation from debris particles (from general corrosion products in the coolant) settling on the index tube so that the collet fingers do not seat properly. Piston seal C-springs made of Alloy X-750 have failed from IGSCC. The Alloy X-750 coupling spud may experience IGSCC, causing failure and separation of the CRA and CRDM. Valve diaphragms and other components made of rubber

Table 11.5. Estimated fluences (n/cm^2) at reactor internals locations over 40-year life[8]

Reactor	Component	Measurement	Reproducibility	Calculation
BWR/6	Shroud	—	—	4×10^{20}
BWR/6	Top guide	—	—	4×10^{20}
BWR/6	Core plate	—	—	3×10^{20}
BWR/6	Jet pumps	—	—	1×10^{19}
BWR/6	Fuel support	—	—	5×10^{21}
Dresden 2	Outside shroud	6×10^{19}	±50%	8×10^{19}
Humboldt Bay	Outside shroud	8×10^{20}	±30%	2×10^{20}

(BUNA-N) and nylon, which have limited shelf lives, can also degrade.

The jet pump components, core shroud, core plate, feedwater spargers, and the baffle plate are also susceptible to IGSCC, whereas the top guide is particularly susceptible to IASCC.[5] Welds attaching the reactor internals (such as baffle plate, jet pump riser braces, core spray and feedwater spargers, and steam dryer support brackets) to the reactor vessel wall are susceptible to IGSCC and fatigue.

In February 1970, the holddown beam assembly of a jet pump failed at the Dresden 3 plant.[11] Similar cracks were discovered at the Quad Cities 2, Pilgrim, Millstone 1, and Vermont Yankee plants. IGSCC occurred across the ligament sections of the Alloy X-750 beams (see Figure 11.18).[12] The restrainer brackets and instrumentation lines in BWR jet pumps have also experienced degradation, the former from improper assembly, the latter from flow-induced vibration.[13] Degradation of the core shroud during normal operation is generally not a concern, but it has been judged to be the reactor internals location most susceptible to thermal shock following a design-basis accident.[14] Feedwater sparger heads have experienced fatigue and IGSCC problems.[15] Sparger failures were first observed in 1972 at the Millstone 1 plant.[11] The problem has apparently been corrected after about three redesigns. In the meantime, sparger failures were also discovered at the Monticello, Dresden 2 and 3, and Quad Cities 1 and 2 plants. These problems occurred at about the same time as the vibration-induced failures were occurring in the BWR/3 jet pump supports. The covers for the access holes in the baffle plate (supporting the lower shroud and the jet pump assemblies) have experienced IGSCC[16] in the Peach Bottom Unit 3 plant.[a] Core spray nozzles have experienced cracking in the Dresden 2, Nine Mile Point 1, and Oyster Creek plants. Core spray spargers have cracked in the Oyster Creek and Pilgrim plants.

Several fastener failures have occurred caused by a combination of material sensitivity, stress, corrosion, and flow-induced vibration. The failures involved Alloy 600 fuel-assembly bolts and fingers, shroud head bolts, and Alloy A-286 fuel-assembly bolts.[17] Alloy A-286 steam separator/dryer assembly beams have also failed.[17]

11.5 Degradation Mechanisms

The degradation mechanisms potentially most damaging to BWR CRDMs and reactor internals are IGSCC, IASCC, and fatigue. The mechanisms of general corrosion, thermal embrittlement, and rubber degradation are also discussed.

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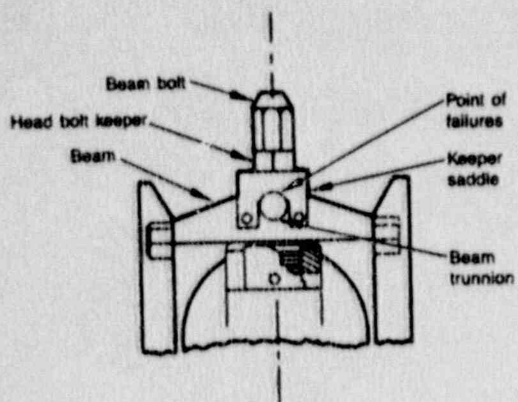
a. Inspections of access hole covers in five other BWR plants (including Peach Bottom 2) showed no such cracking.



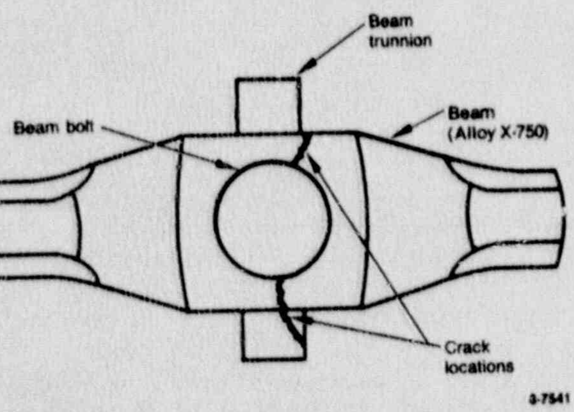


Figure 11.18. Failure locations in jet pump beams (see Figure 11.12 for location at top of the jet pump).[12]

11.5.1 IGSCC. Certain sites on the CRDM pressure housing, especially those that were sensitized[a] as a result of the original manufacturing process, some of the CRDM internal components, and many of the reactor internals components are susceptible to IGSCC. As summarized in Tables 11.6 and 11.7, there have been far more reactor internals IGSCC problems than CRDM IGSCC problems. Included in the tables are significant contributing factors other than the corrosive (high oxygen level) coolant environment. IGSCC has also been a significant problem in BWR austenitic stainless steel (Types 304, 304L, 316 base metal, and 308 weld metal) recirculation piping and safe ends and is discussed in Chapter 12.

A chronology of earlier occurrences of IGSCC in BWR components, including CRDMS and reactor internals follows:[18]

1965. The first IGSCC occurred in the Dresden 1 plant adjacent to a weld in a small diameter pipe. The cracks initiated on the inside surface of the pipe, propagated intergranularly through the sensitized zone adjacent to the weld, and penetrated through the pipe to cause a small leak. Similar cracks occurred at other small diameter pipe locations, especially in the valve bypass lines in the recirculation systems.[19] At least one incident was related to severe cold working.

1967. IGSCC occurred in CRDM stub tubes during construction of the Tarapur (India) and Oyster Creek plants. The tubes are sections of wrought stainless steel pipe that were welded to the vessel lower head prior to the final stress relief of the vessel. The stress relief produced gross sensitization[a] of the stub tubes. Both plants are located near the ocean, and ingress of salt air occurred during construction. Also, the weld fumes and weld spatter from the coated welding electrodes introduced fluorides into the environment. The problem was addressed by substituting Alloy 600 (a material less susceptible to IGSCC than Type 304 stainless steel) for the stub tube, controlling the atmosphere during construction, and banning coated electrodes for weld repairs.[18]

1970. IGSCC occurred in the core spray safe-end weld of the Nine Mile Point 1 plant. The initial filling of the vessel was through the core spray system, with cold deionized water saturated with air. After filling, a dead leg of water remained in the core spray line. A restraining clamp was inadvertantly installed on the colder portion of the vertical run of the core spray line. When the vessel heated to operating temperature, the differences in thermal expansions led to severe bending stresses on the core spray safe end. Through-wall IGSCC developed in the sensitized safe end within several months.

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a. Sensitization of the microstructure of austenitic stainless steel occurs when the material is exposed to temperatures between about 550 and 850°C (1020 and 1560° F) for certain minimum periods of time. This leads to precipitation of chromium carbide particles along the grain boundaries and a depletion of the local chromium content. Once the chromium content in the neighborhood of the grain boundaries falls below about 12%, the material becomes sensitized and susceptible to IGSCC. See Section 12.2 for a more complete discussion.

Table 11.6. History of IGSCC in BWR CRDMs

Location	Date Detected	Material	Contributing Factors
Index tube	1960	17–4 PH Stainless steel	Low-temperature heat treatment
Stub tube welds	1967	Stainless steel	Residual stresses, marine environment, sensitized HAZ[a]
Piston seal C–springs	—	Alloy X–750	High stress (~ 120% of yield stress)
Hydraulic return line[b]	1983	Stainless steel	Pressure stress, sensitized HAZ of weld
Housing flange	1984	Stainless steel	Slight corrosion film, pressure stress

a. HAZ = heat-affected zone.

b. Reference 20.

Table 11.7. History of IGSCC in BWR reactor internals

Location	Date Detected	Material	Contributing Factors
Jet pump holdown beam	1970	Alloy X–750	High applied stress, crevice at thread root, susceptible microstructure
Core spray sparger	1978	Stainless steel	Cold work, sensitization, installation stresses
Supply junction box between vessel wall and shroud	1982	Stainless steel	Sensitized HAZ of weld
Core spray sparger arm weld	1982	Stainless steel	Sensitized HAZ of weld
Jet pump instrumentation penetrations	1984	Stainless steel	Sensitized HAZ of safe end weld
Neutron monitor dry tubes	1984	Stainless steel	High coolant conductivity, high neutron fluence, crevices, oxide wedging
Jet pump safe ends	1985	Stainless steel	High coolant conductivity, crevices, cold work
Shroud head bolts	1986	Stainless steel Alloy 600	High coolant conductivity, residual weld stress, crevices
Access hole cover in shroud support plate (baffle plate)	1988	Alloy 600	High weld residual stress, crevices

1975. IGSCC occurred adjacent to the welds in the 254-mm (10-in.) core spray lines. The common features of these failures were (a) heavy surface grinding in the weld prep counterbore where the crack initiated and (b) intergranular penetration from the inside to the outside surfaces through the sensitized zone.

1977-1978. IGSCC occurred adjacent to welds in the 610-mm (24-in.) piping in a German BWR (KRB Unit A). Similar cracks have been observed in the large-diameter piping of at least five other plants, but to date no through-wall penetrations have occurred.

1979. Cracks were detected in the Alloy 600 safe ends of the recirculation system inlet nozzles on the Duane Arnold BWR plant. The cracks occurred in the crevice near the welded joint between the safe end and an Alloy 600 thermal sleeve, and in the vicinity of an external repair weld that had been made on the safe end. There were high residual stresses in the weld repair area, and SO_4 was a major contributor to the IGSCC.

More recent problems have been found in 16 BWR recirculation piping systems, many of which have had to be replaced, for example, those at Monticello. IGSCC of 17-4 PH stainless steel (such as the index tube and the drive piston head) and Alloy 600 (such as shroud head bolts) has also been observed.

IGSCC generally occurs only where a high level of tensile stress exists in material that is susceptible and subjected to a corrosive environment. The first factor often appears as an inherent result of the normal welding process that was used for assembling piping systems in the currently operating reactors. The resulting residual stresses may be higher than the yield stress at the operating temperature. High stresses may also result from bolt preloads and from applied thermal and mechanical loads.[6,21,22] For example, the jet pump holddown beams are subjected to beam bolt preloads and the hydraulic loads caused by jet pump inlet flow, and the upper surface of the beam experiences tensile bending stresses. The upper surface adjacent to the bolt hole may experience stresses as high as 90 percent of the yield stress, and cracking has been observed at this location, mainly in BWR/3 holddown beams.

The heat treatment of BWR/3 holddown beams, which are made of Alloy X-750, was performed at low solution-annealing temperatures [~885°C (1625°F)] and was followed by thermal aging.[22] The heat treatment resulted in an absence of chromium carbide at grain boundaries and has made the material susceptible to IGSCC. Holddown beams in the later models of BWRs were given heat treatment at higher solution-annealing temperatures [1093°C (2000°F)] followed by thermal aging, which resulted in the presence of chromium carbides at grain boundaries and has made the material resistant to IGSCC. In addition, the later model holddown beams were subjected to lower applied stresses, and, therefore, have experienced little cracking.

Examples of corrodents that promote IGSCC are oxygen, chlorides, fluorides, sulfates, and other sulfur ions. Salt air has sometimes provided the corrodent during construction, and this is thought to be a leading contributor to the CRDM stub-tube-weld failures in some plants. Dissolved oxygen and chloride in the coolant have provided the corrosive environment during operation of BWRs. The PWR reactor coolant systems have a hydrogen overpressure maintained as an oxygen scavenger during power operation. As a result, PWR primary pressure boundary piping has generally not been affected by IGSCC. However, good primary chemistry control (particularly oxygen removal) to prevent this mechanism in BWRs has generally not been the rule, and, thus, the Monticello study ranked IGSCC as the most troublesome life extension problem for the CRDM.[5] In fact, the study concluded that without hydrogen water chemistry (HWC), the CRDM housings are likely to leak at the stub-tube weld during their 40-year intended life.

IGSCC was formerly thought to occur only in sensitized stainless steel; however, a potentially significant problem arose when cracking was found in the Type 316L low-carbon stainless steel jet pump inlet riser safe ends. Such cracking in the safe end thermal sleeve area (see Figure 11.19) may represent an especially significant problem.[23] Indications of such cracking in the Peach Bottom 2 reactor were reported in July 1984. Subsequent examinations found indications in five of the ten riser ends inspected. Ultrasonic test examinations at another BWR plant in 1985 revealed similar indications. General Electric determined that the indications were IGSCC, both on the creviced and noncreviced sides of the weld. Both creviced and noncreviced areas had the same thermal and chemical environment. The noncreviced site had been cold worked. Cold working and crevices are factors that are thought to enhance IGSCC. Some important concerns raised by this discovery are as follows:

- The cracks are in low-carbon stainless steel both in creviced and noncreviced locations
- This represents the first field experience where cracking has occurred in a low-carbon austenitic stainless steel
- The material was not sensitized.

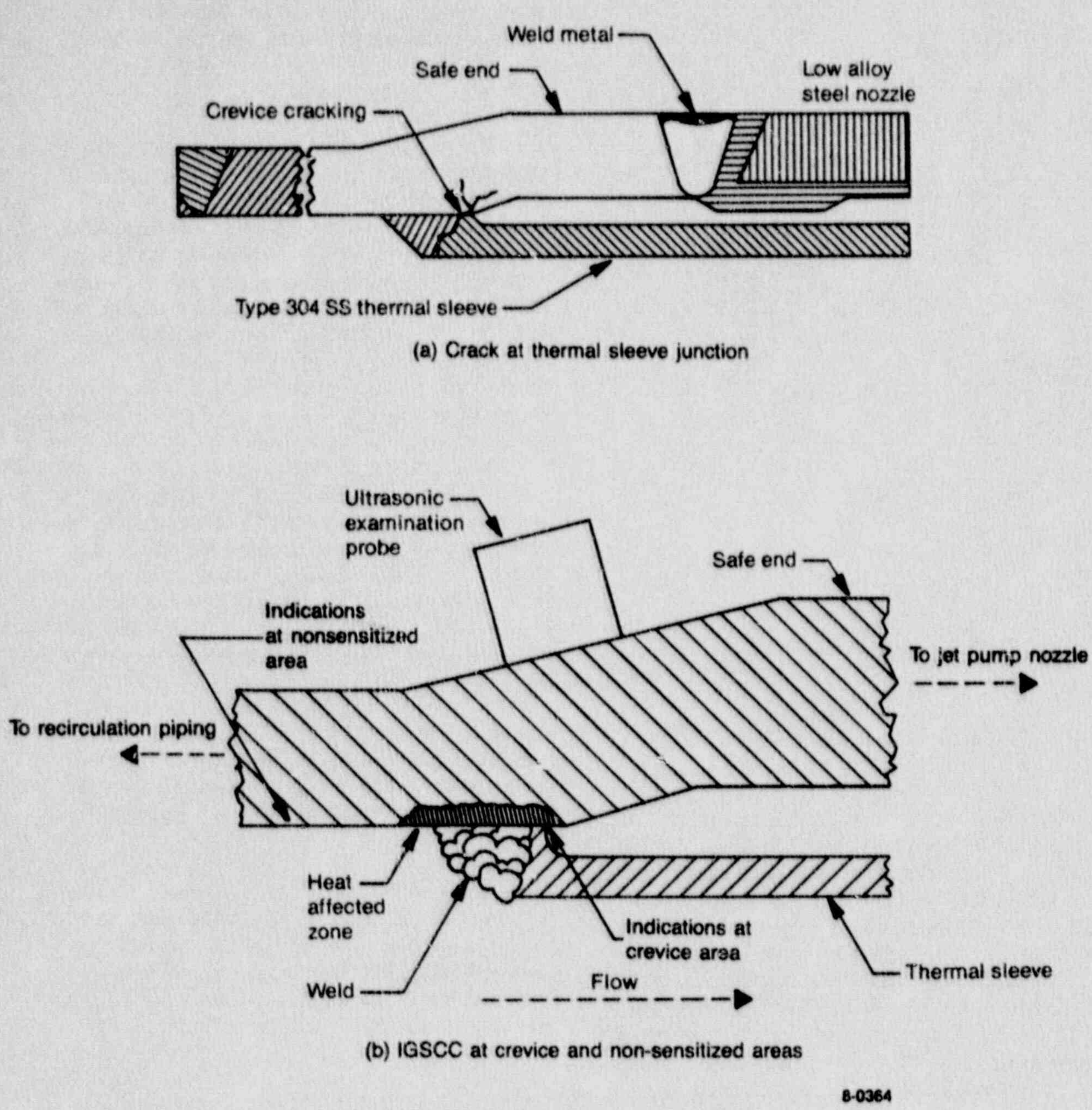


Figure 11.19. IGSCC locations in the Peach Bottom 2 recirculating water inlet nozzle to the jet pump riser.[6,23]

Inspections of creviced low-carbon stainless steel safe ends at another BWR plant, with a lower lifetime average coolant conductivity, revealed no evidence of cracking.[6] Thus, high conductivity is an important contributor to IGSCC.

Cracking was discovered at creviced locations in preloaded Alloy 600 shroud-head bolts at a number of BWR plants in 1986. As illustrated in Figure 11.20, cracking occurred in the creviced region in the vicinity of a weld joining the 304 stainless steel collar to the Alloy 600 bolt. Initiation and growth of the IGSCC were apparently driven by the residual weld stress, but the cracking was sufficiently distant from the weld root that it was not affected by the HAZ.

The bolt thread areas of the failed jet pump Alloy 600 holddown beam (Figure 11.18) also served as stress raisers. CRDM Alloy 600 piston seal C-springs experience stresses as high as 120% of yield stress and are susceptible to IGSCC. The C-springs are replaced at 5-year intervals.[22]

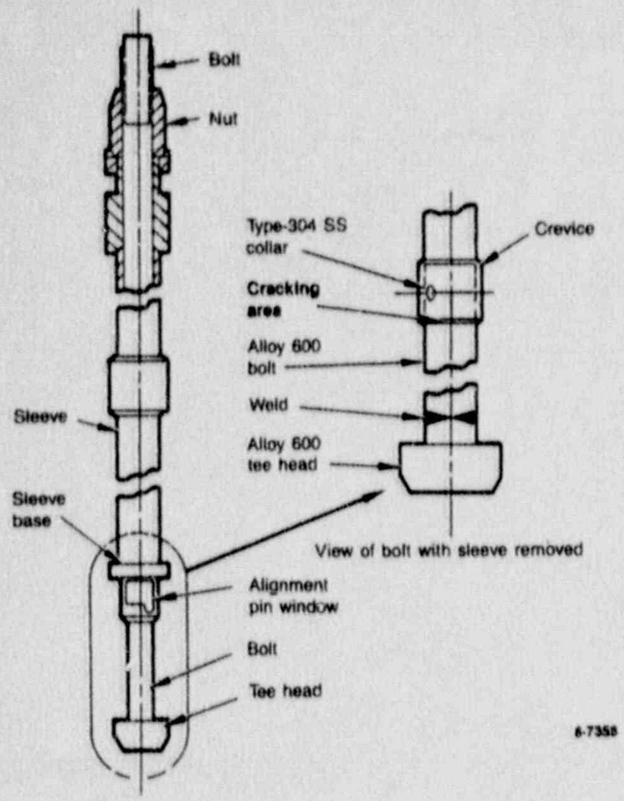


Figure 11.20. Failure location in shroud head bolt.[6]

Intermediate and source range monitor dry tubes are thin-walled stainless steel tubes that contain in-core flux monitoring instrumentation. Tube cracks were first discovered through visual inspection in 1984 and are generally attributed to crevice-accelerated IGSCC and IASCC. The cracking typically initiates in the crevice between the spring housing tube and guide plug, as shown in Figure 11.21. Thick oxide formation in the crevices appears to be the source of the stress. As the oxide grew, it forced open the crevices, a phenomenon termed oxide wedging. Sensitization does not occur in the HAZ because the tube is thin and is cooled quickly and evenly after welding. Fluence levels in this region range from 5 x 10^{21} to 1 x 10^{22} n/cm^2 (>1 MeV).

There also was a strong correlation between plant average coolant conductivity and propensity for cracking (see Figure 11.22) for both shroud head bolts and neutron monitors. Both Figures 11.22a and b show a threshold of about 0.25 μS/cm for initiation of IGSCC. The dry tube data show a linear fit, while the shroud head bolt data increase sharply at the threshold, then level off. Three data points in Figure 11.22a are substantially higher where there were large excursions in the high conductivity not reflected in the average value.

BWRs with jet pumps (BWR/3 and later designs) are designed with two access holes in the shroud support plate (baffle plate in Figure 11.9), which is located at the bottom of the annulus between the core shroud and the reactor vessel wall. The holes, located 180 degrees apart, are used for access during construction and are subsequently closed by welding a plate over the hole. The covers and the shroud support ledge are Alloy 600 material. The connecting weld material also is Alloy 600 (Alloy 182 or 82). The high residual stresses resulting from welding, along with a possible crevice geometry of the weld, when combined with less than ideal water quality present a condition conducive to IGSCC. General Electric has recognized this problem and developed a remotely operated ultrasonic testing capability for detecting cracks in the cover plate welds. The first use of this custom ultrasonic testing fixture was at Peach Bottom Unit 3. In January 1988, intermittent short cracks were found in the weld HAZ around the entire circumference of the covers at Peach Bottom Unit. 3. It is estimated that cracking existed over 50 to 60% of the circumference, with cusps as deep as 70% through the wall. It is possible that the cracking is generic and may affect all BWRs with jet pumps; however, five other plants have been inspected and no access hole cover cracks were discovered.[16]

Other sites of potential IGSCC are the weld between the shroud and core support cylinder, the weld between the shroud and the core-spray-inlet tee, and the beam-to-plate welds in the core plate (because of their creviced geometries), and the HAZ at the CRDM housing welds where residual stresses may be high.

IGSCC cracking of jet pump inlet nozzle welds has also propagated past the weld region and into the low-alloy steel of the reactor vessel.[24,25] The cracks were initiated in the Alloy 600 weld butter material. Three BWR plants have experienced such cracking: Vermont Yankee and Brunswick 2 in the United States and the Chinshan reactor in Taiwan. Since there are also Alloy 600 welds attaching the CRDMs and reactor internals to the reactor vessel (see Figure 11.23 for example), these welds might also experience IGSCC which could propagate to the reactor vessel base metal from the inside. A stress corrosion crack was also found to propagate from the Ni-Cr-Fe clad to the SA-302B base metal of a steam generator in an Italian plant.[26]

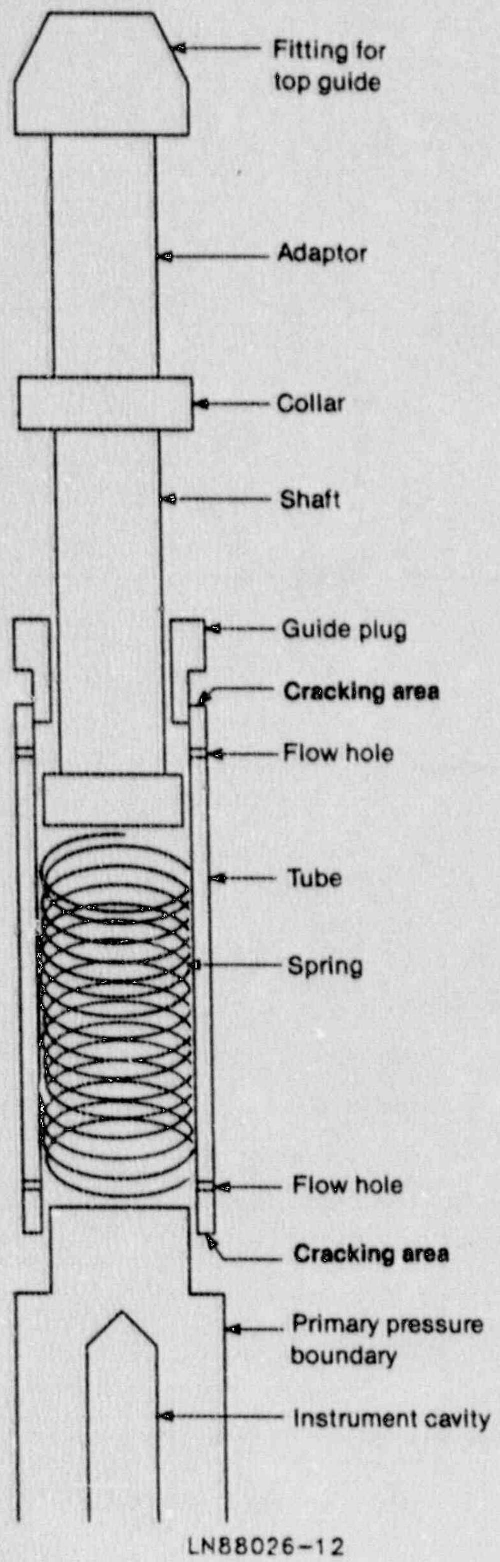
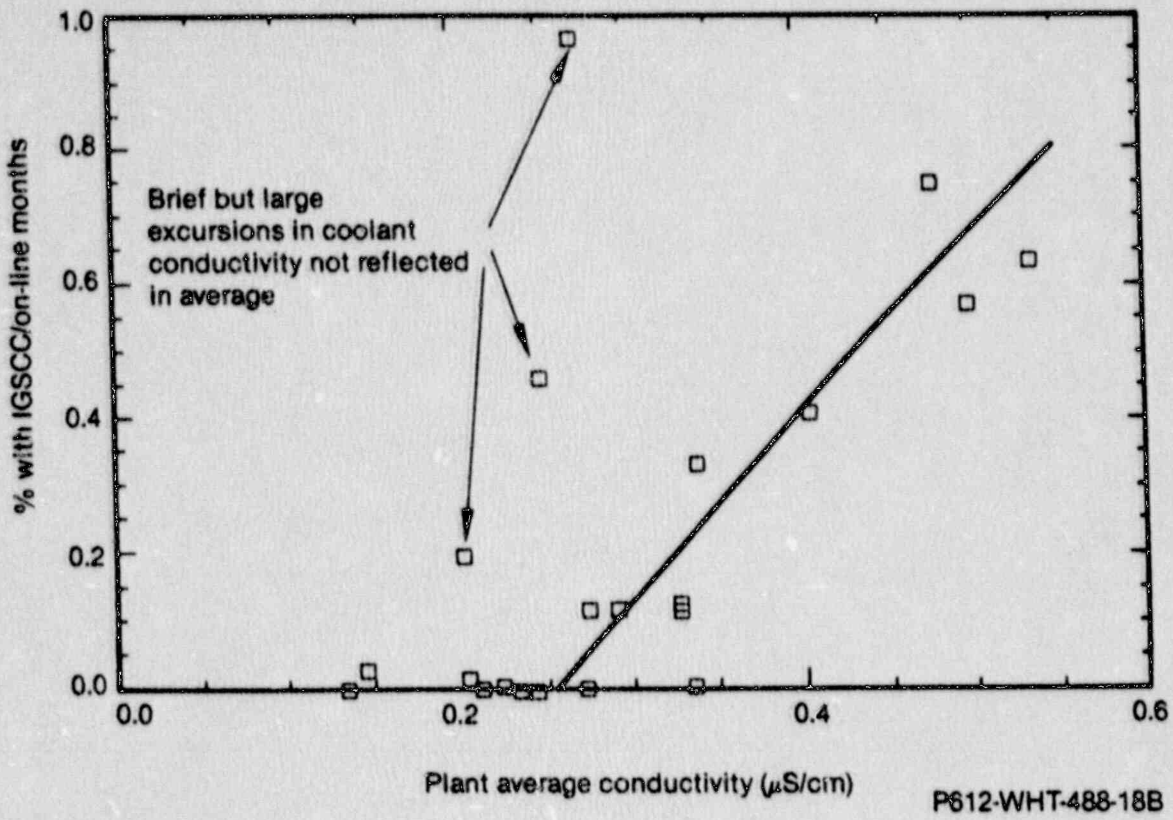
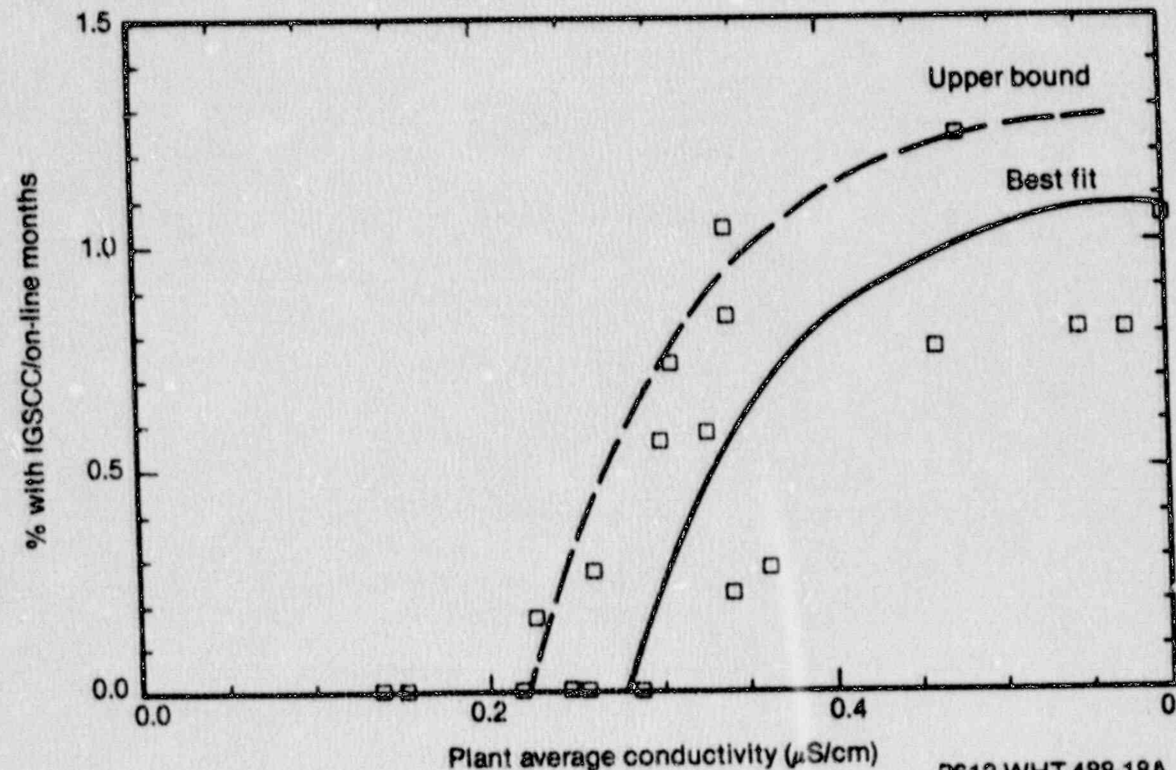


Figure 11.21. Failure location in neutron monitor dry tubes.[6]



a. Dry Tube Data



b. Shroud Head Bolt Data

Figure 11.22. Relationship between conductivity and IGSCC.[6]

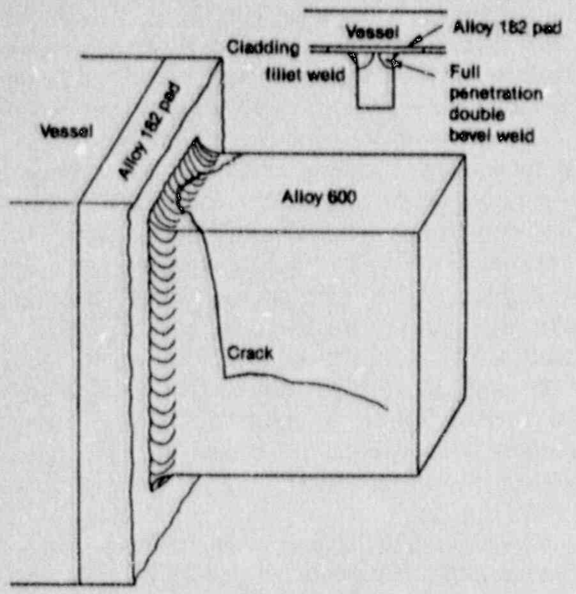


Figure 11.23. Steam dryer support bracket crack.

Hydrogen water chemistry (HWC) is a process that modifies the BWR environment through hydrogen injection in the feedwater. HWC effectively reduces the corrosive potential of the water that produces IGSCC.[27,28] Variations in the water chemistry throughout the core region caused by radiolytic effects influence the degree of protection afforded to different locations within the vessel for a given hydrogen injection rate.[29,30] HWC has been shown to arrest the growth of existing cracks and postpones the initiation of new cracks.[31,32,33] However, the long-term effects of HWC have not yet been demonstrated. The only significant detrimental side effect is increased radiation in the steam system.

11.5.2 IASCC. IASCC, like IGSCC, requires a combination of susceptible material (for example, austenitic stainless steel), a corrosive environment, and tensile stress (but lower than that required for IGSCC). Fast neutron fluence causes depletion of the chromium at the grain boundaries in Type 304 stainless steel, making it prone to stress corrosion cracking where corrosive agents and stress are present.[34] Laboratory tests show that high tensile stresses, crevices, and high fluence levels accelerate cracking.[8,9] However, unlike IGSCC, there is no field evidence that HWC is effective in suppressing IASCC.

Several failures of highly irradiated reactor internal components fabricated of stainless steel are attributed to IASCC. These include failure of fuel cladding tubes (the small uranium dioxide pellets are surrounded by cladding tubes), source–holder tubes, and control rod absorber tubes. Some more recent failures have suggested that cracking can occur in highly irradiated areas with very little applied stress. The failure of a control rod blade handle and recent failures of in-core guide tubes suggest that cracking will begin to occur in stainless steel irradiated to about 5×10^{21} n/cm^2 (>1 MeV).[9] Reference 10 reports a threshold for IASCC of close to 8×10^{20} n/cm^2, whereas Reference 6 reports a cracking threshold of 5×10^{20} n/cm^2 (>1 MeV) based on neutron monitor dry tube experience. Visual and ultrasonic inspection of several top guides in operating plants show no cracking, even though the fluence is at or above the threshold for IASCC. The neutron flux in the CRDM is estimated to be an order of magnitude lower than the IASCC threshold.

As discussed earlier in this chapter, the components addressed in this chapter with the highest neutron flux are the fuel supports, the shroud, and the top guide (see Table 11.5). The instrument slot at the bottom beam of the top guide is a critical location from an IASCC standpoint. A General Electric study concluded that IASCC cracks larger than 76 mm (3 in.) would have to develop in a BWR top guide before failure would occur from a crack initiated at a slot in the bottom beam.[9] However, this study did not consider several factors, the significance of which are not well–understood: radiation–induced swelling, multiple beam failures, refined material properties, and refined fluence estimates.

11.5.3 Fatigue. Another degradation mechanism that affects the CRDM pressure housing is thermal fatigue. However, in contrast to other heavily stressed components, the pressure housing is not highly stressed and has a relatively low fatigue usage factor as predicted by ASME Code analysis methods. (A discussion of the ASME Code fatigue curves and analysis methods is presented in Section 3.4.1.) In fact, a typical fatigue lifetime of 200 years is expected,[5] which means that the fatigue usage over 40 years is 0.2. In addition, the operating transients may be less severe than the design transients used for the calculation. Thus, IGSCC rather than fatigue is likely to be the life–limiting degradation mechanism for the CRDM pressure housing.

Although CRDM designs have included thermal sleeves to minimize thermal gradients in some subcomponents during operational transients, several locations (for example, the index tube and collet assembly) are not well protected and will experience relatively high fatigue usage. As discussed above, these components are cooled to <120°C (<250°F) during normal CRDM operation. However, during a scram and rod insertion, hot reactor water is forced past the CRDM. Subcomponents such as the index tube are then subjected to a severe thermal shock caused by a change in the surrounding temperature of more than 150°C (300°F) almost instantaneously. Also, the different flow paths of the cooling and reactor water can cause the tubes to experience a 150°C (300°F) temperature difference across their walls during control rod motion. CRDM collet housing thermal fatigue failures caused by reactor scrams have occurred in the Dresden 2 and 3, Vermont Yankee, and Browns Ferry 1 plants. CRDM return line nozzles and stainless steel thermal sleeves have cracked in the Peach Bottom 2 and 3 and Hatch 1 plants, among others, from thermal fatigue caused by the alternating flow of relatively cold CRDM return water from the condensate system [10 to 38°C (50 to 100°F)] and hot RPV water [288°C (550°F)]. (There can be a temperature gradient of 288 to 10°C (550 to 50°F) between the top and bottom of the nozzle.)

The weld attaching a steam dryer support bracket to the reactor vessel of a domestic BWR was found to be cracked (see Figure 11.23).[26] A metallurgical examination determined that the bracket failed by a fatigue mechanism. The crack initiation sites were on the side of the bracket, which implies that the bending loads causing fatigue damage were applied in the horizontal direction. It was found that the improperly positioned seismic block had imposed the horizontal bending loads on the bracket and caused the fatigue failure.

The reactor internals component most susceptible to high-cycle fatigue is the jet pump.[5] A jet pump might experience over 10^{10} cycles during its 40-year design life. Although fatigue has not yet caused any jet pumps to fail, the riser support braces have been identified as a potentially life-limited area.[5] Should other reactor internals components, such as the shroud, top guide, or feedwater spargers be damaged by IGSCC or IASCC, fatigue cycling might cause the cracks to grow and cause failure of the component. In fact, feedwater sparger fatigue failures caused by high cycle vibrations (compounded by thermal gradients and leakage between the sparger and nozzle) have occurred in numerous BWRs, including the Millstone 1, Humboldt Bay, Dresden 2 and 3, Quad Cities 2, and Peach Bottom 2 and 3 plants.

11.5.4 Transgranular Stress Corrosion Cracking. Transgranular stress corrosion cracking can take place in a susceptible material (for example, Type 304 stainless steel) exposed to a high chloride concentration, under stress such as caused by internal pressure. The threshold temperature for chloride stress corrosion cracking in Type 304 stainless steel is about 38°C (100°F).

A visual examination performed during a 1988 hydrotest at the Brunswick 2 plant detected weeping from two CRDM withdraw lines. Additional examinations discovered leaking on other withdraw (Schedule 80, 3/4-in. diameter) and insert (Schedule 80, 1-in. diameter) lines. Laboratory analyses of the deposits discovered on the exterior of the Type 304 stainless steel lines revealed high levels of chloride ions. The temperature in the area was judged to have been 35 to 49°C (95 to 120°F). The lines had multiple transgranular stress corrosion cracking originating at the outside surface. The cracks were small and maintained ASME Code design margins for the largest through-wall crack found. The source of the chlorides is unknown, but debris that might have been deposited during plant construction is suspected.[35]

A similar incident occurred in the Duane Arnold plant in 1988. Cable insulation jacket material in an electrical field option box directly above the insert and withdraw lines was degraded from excessive temperature. Moisture from a steam leak above the box condensed on the cable and leached chlorides from the insulation jacket. The water then dropped down on the CRDM insert and withdraw lines and the chloride contamination induced the transgranular stress corrosion cracking.[36]

Complete rupture of a withdraw line would result in a primary coolant leak of about 1 to 3 gpm. The leak rate would still be less than 10 gpm if the Graphitar-14 seals in the CRDM were failed. This rate of loss of coolant could be supplied by makeup water. A break of an insert line would cause a pressure drop resulting in a closure of the ball check valve (see Figure 11.6) that seals the break. An insert line break would also result in loss of cooling water for the seals, and the seals may degrade because of the resulting high temperatures.

11.5.5 General Corrosion/Fouling. One of the operational problems in BWR CRDMs is that of corrosion or corrosion products interfering with the operation of the internal components. An example is improper seating of valves, which permits unintended leakage. A number of problems have been caused in the Dresden 1 plant by foreign material buildup in the collet and drive piston area. This problem, primarily comes from corrosion products in the coolant entering the CRDM rather than corrosion of the CRDM components themselves. The corrosion rate for Types 304 and 316L stainless steels in normal BWR coolant water has been estimated to be very insignificant,[5] low enough to preclude through-wall damage but not CRDM operational problems, since the corrosion particles can be transported from the piping to the CRDM and trapped in the

CRDM. These problems are further discussed in Section 11.6.1.

11.5.6 Thermal Embrittlement. The CF–8 (and CF–3 in some cases) stainless steels and their welds may be subject to thermal embrittlement with prolonged exposure to BWR operating temperatures. These alloys contain as much as 30% ferrite. A high fraction of ferrite in the microstructure is a concern, particularly when the ferrite content exceeds 15%. A significant loss of impact properties has been observed when the ferrite content is above 15% and the material is tested after aging at 400 to 450°C (752 to 840°F) for selected periods of time. However, the thermal embrittlement of cast stainless steel has not been fully investigated, especially at LWR temperatures and long times (many years), and is currently being examined by a Westinghouse Electric Corporation owners' group,[5] EPRI,[37] and an NRC–sponsored program at the Argonne National Laboratory.[38] Life assessment procedures for cast stainless steel components subjected to thermal embrittlement are being developed.

Components made of CF–8 and CF–3 cast stainless steel are listed in Tables 11.2 and 11.3. These include CRDM internal components, such as the collet housing tube, the tube and spacer in the flange and cylinder assembly, and portions of the CRA guide tube. Reactor internals components fabricated from cast stainless steel include the orificed fuel supports, portions of the jet pump (the transition piece casting, the wedge casting, and the diffuser collar casting), and the steam separator/dryer assembly. Thermal aging is discussed in more detail in Section 5.3.2 of Volume 1, and Section 2.3.1 of this report.

11.5.7 Wear. All mating subcomponents in the CRDM experience mechanical wear to varying degrees. Parts that have been degraded by wear in the past include the index tubes (galled), chrome surfacing partially stripped from the collet assembly, the nitrided guide tube roller pins, the index tube, and the drive and stop pistons.[40] Some of this degradation has been caused by foreign particles entering the CRDM. Seals and bushings have also been subject to wear.

General Electric has performed life tests on CRDMs to determine allowable numbers of cycles for design life. Although these tests have not been allowed to progress to the point of absolute failure of the CRDM to function, they nevertheless suggest that with proper preventative maintenance the BWR CRDMs will remain functional during a 40–year life. This type of degradation has not occurred to such an extent (or at a single time) that it has proven to be a plant safety problem. However, it has caused operating problems and required CRDM replacement and/or refurbishment.

11.5.8 Rubber Degradation. Subcomponents made of rubber, such as diaphragms in the CRDM solenoid–operated valves, have restricted shelf and service lives. The material BUNA–N becomes brittle over time; it breaks up and can block vent ports in the scram pilot valves. As with the wear discussed in Section 11.5.6, this type of degradation has not occurred to such an extent that plant safety has been compromised.

11.5.9 Irradiation Embrittlement. Laboratory data indicate that stainless steel looses its toughness at high levels of neutron irradiation. Figure 11.24 shows the decrease in ductility of Type 304 stainless steel with increasing fluence; the percent elongation and reduction in area begin to significantly decrease at about 10^{19} n/cm^2 (>1 MeV), whereas the yield stress increases with fluence, rising more rapidly at about 10^{20} n/cm^2 (>1 MeV).[9]

Irradiation embrittlement of the cast stainless steel austenite phase and thermal embrittlement of the ferrite phase could occur simultaneously. This possibility should be investigated.

11.5.10 Stress Corrosion Cracking. Cracks were discovered in the 4140 medium–strength alloy steel bolts holding down the 185 CRDMs of the Susquehanna 2 plant in May 1988.[41] Each CRDM is secured to the containment floor by eight bolts passing through a flange. Inspection of all 1,480 bolts disclosed that 27% had stress corrosion cracking where the head and shank join. The likely cause was trapped moisture underneath the reactor vessel. The utility now plans to replace these bolts at 10– to 12–year intervals. This phenomenon has not been reported at other BWRs.

11.5.11 Erosion. There are high flow rates in the reactor internals areas. The flow velocity is highest in the jet pumps, which are considered to be the components most susceptible to erosion. However, Type 304 stainless steel is highly resistant to erosion, and the probability of erosion–induced failure is low.

11.6. Potential Failure Modes

Some of the past failures of BWR CRDMs and reactor internals are listed in Sections 11.6.1 and 11.6.2, respectively. These have presented no major safety problems, but are indicators of what might go wrong and lead to more serious events.

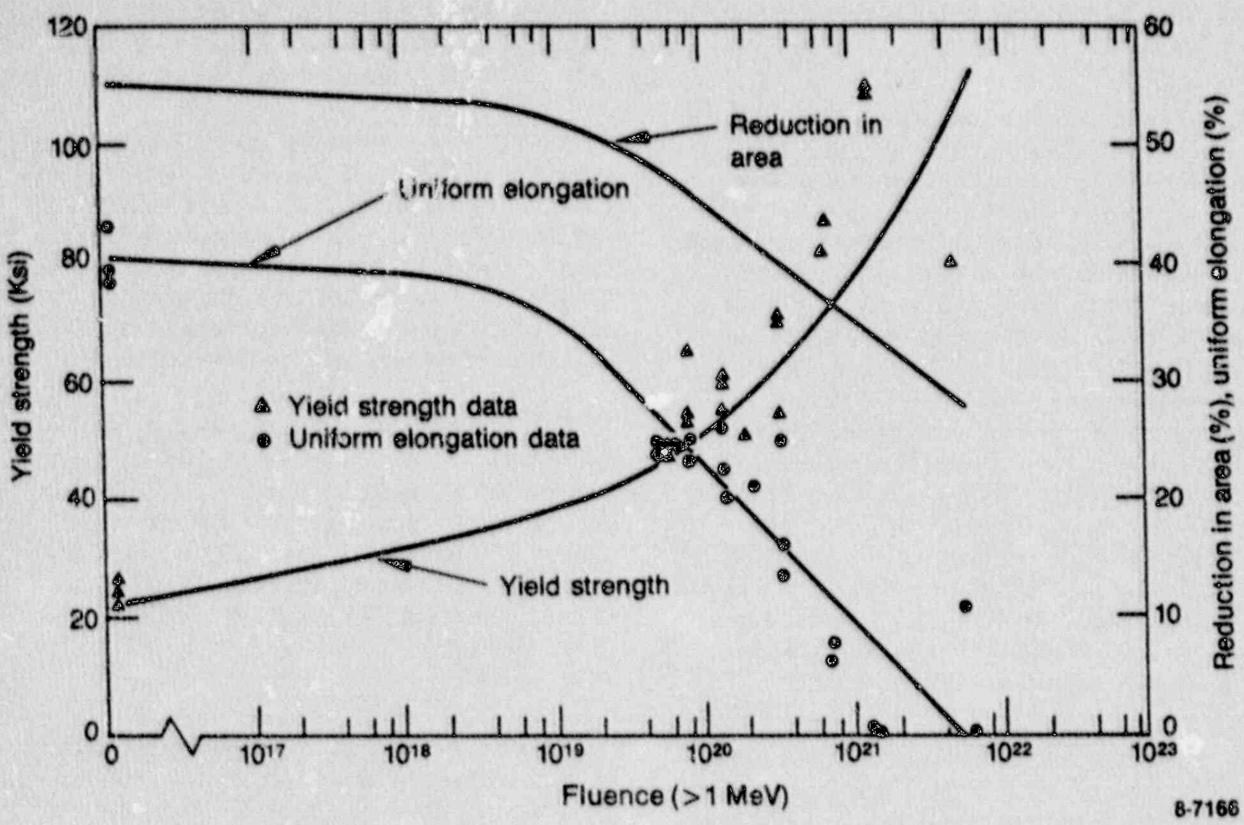


Figure 11.24. Change in Type 304 stainless steel parameters with irradiation at 288°C (550°F).[8]

11.6.1 CRDMs. CRDM housing leaks were discovered at Nine Mile Point 1 in 1983–1984.[42] The cause is believed to have been IGSCC that occurred in the HAZ of the stub tube between the CRDM and RPV (see Figure 11.2). In most cases, such leaks cause reactor shutdown and subsequent metal repair. The stub tube problem can be resolved by substituting Alloy 600 for the original stainless steel stub tubes, or by cladding the Type 304 stainless steel tubes with 308L weld metal; controlling the atmosphere during construction; and banning coated electrodes for weld repairs.[18] The worst-case pressure boundary failure scenario is a housing rupture and a rod ejection accident, which is addressed in the safety analysis, and is resisted by the CRDM support. A small-break loss-of-coolant accident would also occur during this scenario.

The most common CRDM failure mode is the inability of a rod to move properly. This includes rod motion with no signal, rod drift, failure to insert upon actuation, or failure to insert fully. Several methods to achieve rod operation, including manual operation of the air-operated valves, are possible. When a CRDM fails to operate properly, that particular CRDM can be valved out, and plant operation can continue, provided that a predetermined number of rods are operable. If a continuing problem exists that the utility cannot tolerate, replacement or refurbishment of the CRDM is necessary. CRDM changeouts at Browns Ferry 1, 2, 3, Fitzpatrick, Peach Bottom 2, and Dresden 2 occurred in 1983–1984.[42]

CRDM inoperability has been caused by a number of factors. In June 1980, 76 of the 195 control rods at Browns Ferry 3 failed to fully insert during a manual scram.[43] Subsequent investigation disclosed that the Scram Discharge Volume (SDV) was 80% filled with water caused by a malfunction of the vent system (a stuck ball in a check valve), which prevented adequate drainage. Thus, the discharge water could not be completely removed through the withdraw line, and the CRDM could not complete its stroke.

Three control rods failed to insert during a scram-time test in December 1985 at Millstone 1.[44] The causes in one case were attributed to deterioration of the BUNA-N valve disc material within the valve, and in the other two cases to a misalignment. The BUNA-N becomes brittle over time, breaks up, and sometimes blocks the vent ports in the valves, as discussed above. The shelf life of this subcomponent is estimated to be only seven years.

Rod insertion by a single CRDM occurred in the Nine Mile Point 1 plant in 1986 when the diaphragm in the air operator of the scram outlet valve failed.[45] The failure was attributed to aging of the rubber (BUNA-N and nylon material), causing a radial crack to develop. Niagara Mohawk Power Corporation had previously changed out the diaphragms in approximately one half of the CRDMs in 1975 and 1976.

A CRDM was found to be stuck during full-scram preoperational tests at Clinton in April 1986.[46] Investigation revealed that the scram discharge riser manual isolation valve was in the incorrect (closed) position. The closed valve caused a very high pressure to develop within the CRDM, crushing the index tube. This caused interference with the movement of the piston and, thus, the rod stuck. The rod was ultimately freed by cutting the index tube into two pieces and removing it. Similar incidents occurred at the Quad Cities 2 plant in October 1984, and at the Perry plant in April 1985. At the Dresden 3 plant in October 1984, the scram discharge riser manual isolation valve disc separated from the stem, causing yet another problem of this kind.

In July 1986, the Grand Gulf plant experienced an uncontrolled single CRDM withdrawal to the full-out position while at 69% power. The licensee concluded after investigation that temporary particulate accumulation on the valve (DCV 122 in Figure 11.8) seating surface caused incomplete closure of the valve when the withdraw command was terminated, allowing drive water to leak past the valve and force the drive piston downward.[47]

The frequency of CRDM problems was about 1.3 incidents per year prior to 1978 and increased to 3.7 incidents per year in 1978 and 1979.[48] The data base does not as yet have the information required to project at what point in a BWR lifetime the CRDMs would be expected to experience significant aging-related failure. BWR CRDMs must periodically be removed from the reactor and rebuilt in order to ensure that they continue to meet performance criteria. The most common problem that requires rebuilding is worn seals. Current guidelines at several plants call for rebuilding 10% of the CRDMs during each outage. Several plants report that they rebuild more than 10%, one stating that they replaced or rebuilt nearly 50% of the drives during one plant outage.[11]

11.6.2 Reactor Internals. The reactor internals provide positioning and support of the fuel and control rods. Loss of mechanical integrity could cause reactivity accidents caused by fuel relocation or inability to insert the control rods. Since the reactor internals direct the coolant flow inside the RPV and through the core, their damage could also cause local hot spots within the core region, or flow-induced vibration failures of core components. For example, if the baffle plate hole covers failed, some of the coolant flow would bypass the jet pumps, ECCS would not be able to flood the core to the two-thirds level, and a loose part could cause damage to the recirculation pumps. Failure in the steam separator/steam dryer assembly could cause low-quality steam to be transmitted to the steam lines and steam turbines, thereby causing erosion-corrosion problems in the steam system.

As discussed elsewhere in this chapter, IGSCC field failures of BWR internals have included the jet pump holddown beam, the jet pump instrumentation penetrations, the core spray sparger, the supply junction box between the vessel wall and shroud, neutron monitor dry tubes, and the shroud head bolts. Highly stressed areas with sensitized metal, cold work, or crevices are susceptible to IGSCC. There is potential concern that an IGSCC crack in the attachment welds may propagate in the reactor vessel base metal.

Field failures of feedwater spargers have been caused by high-cycle vibration compounded by stresses induced by thermal gradients between the feedwater and sparger walls. The jet pumps are also potentially susceptible to high-cycle fatigue caused by flow-induced vibrations, though there have been no failures to date.

The top guide, shroud, and fuel supports will have a high cumulative neutron fluence at the end of the 40-year life, making these locations potentially susceptible to IASCC failures after long periods of exposure. Cast stainless steel subcomponents, such as portions of the steam separator/dryer and jet pump assemblies, are susceptible to thermal embrittlement; though again, there has been no evidence of this phenomenon in the BWR reactor internals. Cast stainless steel components subject to high levels of radiation are susceptible to both irradiation and thermal embrittlement, and the potential failure mode is brittle fracture.

11.7 Inservice Inspection and Surveillance Requirements

Formal guidelines for inspection of the CRDM housing welds are listed in Table IWB-2500-1 of Reference 49 (Section XI of the ASME Code). It calls for volumetric inspection of 10% of the peripheral CRDM housings during each inspection period. In the same section, requirements for visual inspection of the CRDM bolts, studs, and nuts are listed.

The stub tube welds are very difficult to inspect, and inspections have been conducted at only a few BWRs with stub tubes because of inaccessibility. Inspection of these welds should be performed, possibly by using a remote ultrasonic testing probe on the interior of the vessel. A program to develop remote ultrasonic testing methods of inspection was recommended in the Monticello study.[5]

There are no required inservice inspections for the interior of the CRDM. Furthermore, no suitable methods have been developed to identify areas of impending failures. For example, there is no method to determine when hydraulic valves are prone to stick. Sticking is detected only after the situation has occurred. CRDM operability is determined by functional tests.

Although not required by the ASME Code, areas with a history of problems or where known problems exist are inspected visually on a case-by-case basis. Approximately 10% of the CRDMs are repaired or replaced during each outage at many BWRs.

Four CRDMs are normally picked at random from the General Electric production stock each year and subjected to various tests under simulated reactor conditions and to more than one eighth of the cycles specified in the design requirements.[1] When a significant design change is made in CRDMs, the drive is subjected to a series of tests equivalent to 1.5 times the required life cycles. For example, two CRDMs underwent such testing in 1976, and met or exceeded the minimum specified performance requirements.[1]

Table IWB-2500-1 of Section XI of the ASME Code[49] also calls for visual examinations of accessible surfaces of the core support structures and of welds of interior attachments to the RPV at refueling outages. Visual examinations are useful to determine the locations of deteriorated areas and the nature of the deterioration. These locations can then be subjected to more detailed examinations. However, visual examinations cannot reveal all types of surface degradations, and tight cracks would probably be overlooked in these inspections. Inspection of the reactor internals is especially difficult because of the high-radiation fields in the core area. Thus, remote video cameras are used for underwater visual examinations of the reactor internals.

ASME visual examinations are categorized as either VT-1 or VT-3. VT-1 examinations are used to identify cracks, wear corrosion, or physical damage on the surface of the part or component. To properly perform a VT-1 examination, there must be sufficient access to allow the eyes to be within 610 mm (24 in.) of the surface, which is not practical inside a reactor vessel. Section XI allows remote examinations, including the use of mirrors. However, these must be capable of resolution equal to, or better than, direct visual examinations. VT-3 examinations determine the general mechanical and structural conditions of components such as clearances, settings, loose or missing parts, debris, corrosion, wear, or erosion. Typically these in-service examinations have been performed using underwater cameras, which may be suspended up to 5.7 m (75 ft) below the examiner. One company has developed a remotely operated vehicle equipped with mounted cameras and lights that can be positioned underwater to perform visual examinations.[50]

The present ASME code requirements for inspection of the reactor internals are not sufficient to adequately identify most aging-related degradation. In fact, most of the failures discussed in this chapter were not detected by the required inservice inspection methods. Many of the susceptible locations are not accessible for inspection, for example, the interior of the jet pumps, and it is not possible to see tight cracks, subsurface anomalies, etc. Ultrasonic testing is very valuable to detect subsurface cracks, local thinning, or other anomalies internal to the component, and could be developed for better inspections of the reactor internals.

IGSCC and IASCC cracks in the reactor internals can be indirectly monitored with a self-loaded, double-cantilever beam stress-corrosion monitor, shown in Figure 11.25.[51] This monitor is based on application of the reversing dc electrical potential technique, which permits remote measurement of crack growth in the cantilever beam. This technique can accurately measure a crack growth of less than 0.01 mm. The monitor can be easily inserted into the reactor and does not affect the plant operation. A 150-mm-(6-in.-) long version of the monitor has been successfully used both in the laboratory and in the reactor.

11.8 Summary, Conclusions, and Recommendations

Many of the factors that must be understood for accurate CRDM lifetime predictions are unknown. Whereas the fatigue usage of the pressure housings can be calculated, IGSCC failures are very difficult to predict

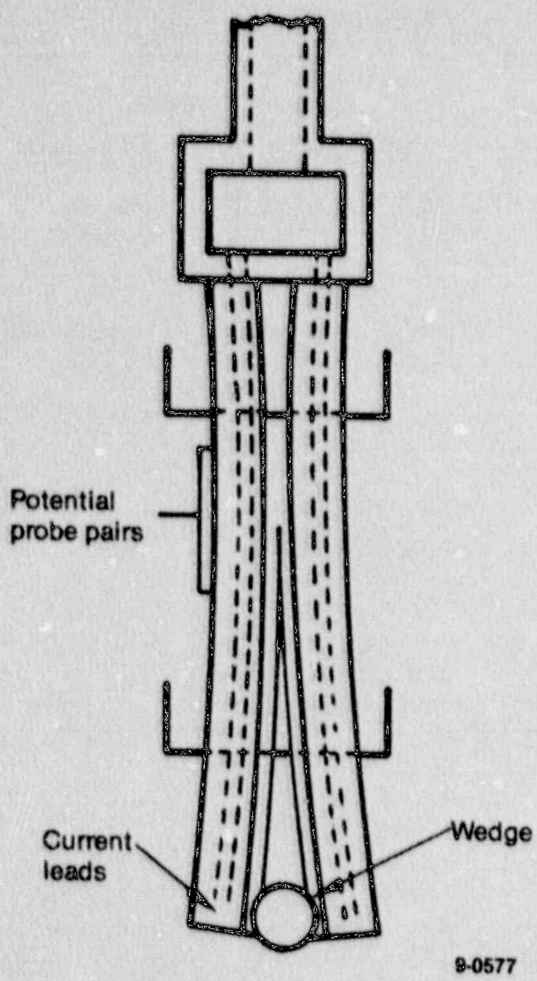


Figure 11.25. Self-loaded, double cantilever beam stress-corrosion monitor.

and there are still many subcomponents for which there is no suitable lifetime prediction information. These include the lifetimes of the valves and wear of the latching mechanisms. Some BWR CRDMs have operated successfully for over 20 years, but there is not enough information at present to predict the overall CRDM lifetime. Based on the information to date, the critical locations in order of importance are listed in Table 11.8.

Conclusions and recommendations for CRDMs are as follows:

1. IGSCC is the major degradation mechanism for the welds between the CRDM housing and the vessel lower head. Stub tubes are employed between the CRDM housing and the vessel in the older BWRs, and the heat-affected zones near the stub tube welds have experienced IGSCC cracks. It is difficult to inspect these welds, and remote inspections methods are needed to assess their integrity.

2. Hydrogen water chemistry (HWC) is an effective mitigation method for IGSCC damage. HWC significantly reduces the level of oxygen in the BWR coolant and, thus, eliminates a stressor required for the IGSCC mechanism to be present.

3. The CRDM internals should be inspected periodically for excessive wear damage. Monitoring of the cumulative number of insertions and withdrawals would help to make decisions related to CRDM replacement.

4. The diaphragms and discs in the solenoid-operated valves become brittle over time and break up. The broken diaphragm pieces may block the vent ports in the scram pilot valves, and plant safety may be compromised.

5. Thermal embrittlement is a potential degradation mechanism for the portions of the CRDM guide tubes and fuel supports, which are made of cast stainless steel. Because the guide tubes transmit most of the weight of the core to the vessel lower head, the damage caused by thermal embrittlement needs to be evaluated.

It is important to note that most of the CRDM subcomponents can be relatively easily replaced without having to replace the entire CRDM. Also, the technology for CRDM replacement is available, and full changeouts have been made. Thus, the CRDM issues are generally not those of feasibility.

Critical locations for the reactor internals are listed in order of importance in Table 11.9. The degradation mechanism of concern is IGSCC, which is currently thought to be the overall life-limiting mechanism. As with CRDMs, prompt initiation of HWC could be very beneficial in reducing IGSCC. The other primary mechanisms of concern are IASCC and fatigue.

Conclusions and recommendations for reactor internals are as follows:

1. Attachment welds of the reactor internals to the reactor vessel may contain sensitized material, and IGSCC cracks may propagate from the weld heat-affected zone into the pressure vessel base metal. These welds are generally difficult to inspect. Remote inspection tools for these sites should be developed.

Table 11.8. Summary of degradation processes for BWR control rod drive mechanisms

Rank	Degradation Sites	Stressors	Degradation Mechanisms	Potential Failure Modes	ISI Methods
1	Pressure housing, stub tube	Corrosive water, thermal stress, residual stress	IGSCC, fatigue	Crack leading to leak	Volumetric, surface
2	Latching mechanism (collet assembly and index tube)	Thermal transients, corrosive water, rubbing, impacting	Wear, IGSCC, fatigue	Binding, stuck rods	None
3	Piston seal C-spring	Preloads, corrosive water	IGSCC	Stuck rod	None
4	Hydraulic control system	Thermal stress, corrosive water, debris, improper maintenance, overpressure, misalignment	Valve diaphragm embrittlement and cracking	Stuck rods, unintentional rod movement	None
5	Piston seals	Temperature, corrosive water	Embrittlement, wear	Stuck rod	None

2. IGSCC is the major degradation mechanism for the reactor internals. Sensitized, creviced, and cold-worked material is especially susceptible to IGSCC. IGSCC increases significantly when the coolant conductivity increases above 0.25 μS/cm.

3. IASCC is a potential degradation mechanism for components subjected to high fluence, such as the top guide. The threshold for IASCC damage is about 5 x 10^{21}nvt. A better understanding is needed to evaluate the damage associated with IASCC.

4. Hydrogen water chemistry (HWC) is a potentially effective mitigation method for IGSCC damage. HWC significantly reduces the level of oxygen in the BWR coolant and thus mitigates IGSCC damage. However, HWC remains to be proven in the field as an effective mitigation method for IASCC. The long-term effects, and possible side effects, of HWC also need to be evaluated.

5. The feedwater spargers and jet pumps are susceptible to high-cycle fatigue damage. For these stainless steel components, fatigue-crack initiation and growth-rate data in a HWC environment are needed.

6. Research should continue on the thermal embrittlement of the ferrite phase of cast stainless steel components, and on irradiation embrittlement of components in high flux areas. The possibility of thermal embrittlement of the ferrite phase and irradiation embrittlement of the austenitic phase of cast stainless steels should be investigated.

Table 11.9. Summary of degradation processes for BWR reactor internals

Rank	Degradation Sites	Stressors	Degradation Mechanisms	Potential Failure Modes	ISI Methods
1	Attachment welds to reactor vessel	Residual stress, corrosive water, temperature, flow–induced vibrations, dead weight	IGSCC, Fatigue	Crack progressing into reactor vessel	Visual[a]
2	Core shroud (including bolts)	Residual stresses, corrosive water, preloads	IGSCC	Crack leading to loss of fuel geometry	Visual[a]
3	Core plate	Flow–induced vibrations, corrosive water, dead weight	IGSCC	Crack leading to loss of fuel geometry	Visual[a]
4	Jet pumps	Preloads, hydraulic loads, corrosive water, flow–induced vibration, temperature	IGSCC, fatigue, erosion, thermal embrittlement	Loss of adequate core flow	Visual[a]
5	Top guide	Radiation, thermal stress, corrosive water, flow–induced vibrations, dead weight	IASCC, IGSCC	Crack leading to loss of fuel geometry	Visual[a]
6	Core spray spargers and piping	Flow–induced vibrations, corrosive water, temperature	IGSCC, fatigue	Loss of effective ECCS	Visual[a]
7	Feedwater spargers	Flow–induced vibration, corrosive water	Fatigue, IGSCC	Improper feedwater flow	Visual[a]
8	Fuel assembly supports	Corrosive water, flow–induced vibration, radiation, temperature, dead weight of fuel	IGSCC, fatigue, IASCC, thermal embrittlement	Loss of fuel geometry	Visual[a]
9.	Baffle plate access hole covers	Residual stress, corrosive water, temperature	IGSCC	Improper core flow	Visual[a]
10	Steam separator/ dryer bolts	Corrosive steam, flow induced vibration, temperature, preload	IGSCC, fatigue, thermal embrittlement	Damage to steam lines lines and turbines	Visual[a]

a. Accessible surfaces and welds of vessel attachments.

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12. COUNTERMEASURES FOR CRACKING IN BOILING WATER REACTOR RECIRCULATION PIPING

B. J. Buescher and U. P. Sinha

12.1 Introduction

Incidents of cracking and leaking in Boiling Water Reactor (BWR) austenitic stainless steel piping have been occurring since shortly after the introduction of the first commercial plants. The first incident was reported in December 1965 at Dresden 1 when a leak was discovered in a 15.2-cm (6-in.) Type 304 stainless steel recirculation bypass line.[1] By September 1974, cracks had been found in the piping of six BWRs.[2] Pipe cracking first occurred in the heat-affected zones of the small-diameter [20.3-cm (8-in.) or less] 304 stainless steel piping welds and in furnace sensitized[a] components, and is attributed to intergranular stress corrosion cracking (IGSCC). With increased operating time, cracks were discovered in larger-diameter piping. By January 1979, a total of 133 occurrences of pipe cracking in BWRs had been reported.[3] Except for heat-sensitized safe ends, the pipe cracking had been limited to piping of 30.5-cm (12-in.) diameter or less. Table 12.1 (from Reference 2) summarizes the pipe cracking experience through January 1979.

Extensive cracking and leaking, including through-wall axial cracking, were discovered in the 711-mm- (28-in.-) diameter recirculation piping safe end at the Nine Mile Point BWR in 1982. The probability of cracking in large diameter piping was thought to be quite low until this occurrence. The discovery of cracks in the large-diameter BWR piping led to augmented inspections of the piping in the BWR recirculation systems [as directed by the U.S. Nuclear Regulatory Commission Office of Inspection and Enforcement (I&E) in Bulletins 82-03 and 83-02] using more sensitive ultrasonic testing procedures.[3,4] The augmented inspections of the large-piping systems revealed extensive cracking at most BWR plants, many of which required repair or replacement to meet ASME code requirements prior to further operation.[5] The results of the initial round of BWR inspections conducted under I&E Bulletins 82-03 and 83-02 are summarized in Table 12.2, as reported in Reference 5.

The BWR recirculation system consists of safe ends and pipes, fittings, welds, and recirculation pumps. Recirculation pumps are discussed in Chapter 2 and, therefore, are not discussed here. The joint between the reactor pressure vessel nozzle and the piping system is made up of a transition piece of pipe called *a safe end*. The entire weldment in some of the older

Table 12.1. IGSCC incidents through January 1979 by line type in U.S. and foreign BWRs[a,2]

	Before July 75	July 75 to January 79	Total
Recirculation bypass (4 in.)	30	12	42
Core spray (10 in.)	16	17	33
Control rod drive (3 in.)	1	1	2
Reactor water cleanup (3 to 8 in.)	10	14	24
Large recirculation (≤12 in.)	0	13	13
Small (3 in.), other than CRD & RWCU	0	6	6
Other	7	6[b]	13
	64	69	133

a. Cracking incidents reported to the NRC.

b. Cracking incidents in large-diameter piping in German BWRs.

a. A sensitized austenitic stainless steel material is susceptible to intergranular stress corrosion cracking because of thermally induced grain boundary chromium depletion.

Table 12.2. Summary of the number of welds inspected and cracks identified in the large BWR piping, inspected according to IEB 82-03 and 83-02[5]

	Extent of Inspection (% of welds inspected)		Inspection Results (number of cracked welds)		Number of Weld Overlays Repaired
Plants	Recirculation	Residual Heat Removal	Recirculation	Residual Heat Removal	
Big Rock Point	20% (11 of 59)	—	0	—	0
Browns Ferry 1	98% (103 of 105)	90% (36 of 40)	33	14	42
Browns Ferry 2	27% (25 of 91)	28% (9 of 32)	2	0	0
Browns Ferry 3	98% (103 of 105)	28% (9 of 32)	0	0	0
Brunswick 1	25% (29 of 115)	75% (3 of 4)	3	0	3
Brunswick 2	100% (102 of 102)	100% (5 of 5)	15	1	8
Cooper	100% (108 of 108)	100% (7 of 7)	20	0	13
Dresden 2	47% (47 of 101)	10% (4 of 40)	10	0	7
Dresden 3	100% (115 of 115)	90% (45 of 50)	53[a]	11[b]	61
Duane Arnold	42% (49 of 117)	40% (2 of 5)	0	0	0
Fitzpatrick	47% (49 of 106)	45% (5 of 11)	1	0	0
Hatch 1	47% (47 of 100)	100% (11 of 11)	5	2	6
Hatch 2	94% (97 of 103)	100% (11 of 11)	36	3	27
Millstone 1	11% (11 of 100)	0% (0 of 46)	0	0	0
Monticello	100% (106 of 106)	78% (18 of 23)	6	0	6
Nine Mile Pt. 1	82% (62 of 76)	—	53	0	0
Oyster Creek	39% (31 of 80)	—	0	0	0
Peach Bottom 2	100% (91 of 91)	91% (32 of 35)	19	7	21
Peach Bottom 3	91% (77 of 85)	92% (35 of 38)	10	5	15
Pilgrim 1					
Quad Cities 1	8% (9 of 100)	20% (9 of 44)	0	0	0
Quad Cities 2	100% (106 of 106)	90% (45 of 50)	20	2	9
Vermont Yankee	66% (58 of 88)	7% (2 of 30)	33	1	22

a. Note that 18 welds originally reported to be cracked were later reevaluated and determined not to be cracked, so are not included in these totals.

b. After inspecting approximately seven welds and finding cracks in four of them, the utility decided to replace the piping with Type 316NG, so the examination has not been completed.

BWR plants, including the nozzle and safe end, was given a postweld heat treatment after the nozzle-to-safe end weld was made. This procedure gave rise to a furnace sensitized safe end that was highly susceptible to IGSCC. However, the postweld heat treatment in the later BWR plants was performed after buttering the nozzle, and then the nozzle-to-safe end weld was made. The materials used in fabricating BWR recirculation piping are listed in Table 12.3.[6]

Austenitic stainless steels are ductile and quite tough. A review of the field data has shown that despite widespread IGSCC in BWR austenitic stainless steel piping, no pipe breaks have occurred (only cracks, some of which resulted in leaks, have occurred). In addition, field observations and measurements show that there are azimuthal variations in the weld residual stresses and variations in material sensitizations. Therefore, leaks can generally be expected

Table 12.3. Typical BWR recirculation system materials

Component	Materials		
Piping	Types 304 SS, 316NG SS		
Fitting	Grades CF-8, CF-8 M		
Safe end	Types 316, 316NG, 304 SS, Alloy 600		
Pipe-to-pipe and pipe-to-elbow welds	Type 308L		
	Weld Material	Nozzle Butter	Safe end Butter
Safe end-to-nozzle weld (dissimilar metal welds)	Type 308L/308	Type 308L	None
		or	
	Alloy I-182/ Alloy I-82	Alloy I-182	None or Alloy I-182

to develop well before an actual pipe break occurs.[7] After reviewing both the field data and analytical studies, the NRC Pipe Crack Task Group came to the same conclusion.[5] Therefore, IGSCC of BWR piping is not considered a major threat to plants. However, IGSCC does result in degradation of the primary pressure boundary, and the widespread cracking observed does result in a reduction in the defense-in-depth required in the general design criteria and results in a reduction in the overall plant safety margins. For this reason, the reactor licensees must be able to demonstrate that any cracking discovered will remain small enough during a period of continued operation that the minimum safety margin of the original piping design is maintained. Inspection and repair of affected piping has also resulted in additional radiation exposure of the plant staff.

In addition to IGSCC, degradation of the BWR recirculation piping can be caused by thermal embrittlement and fatigue. These degradation mechanisms are addressed in some detail in Volume 1 of this report.

Table 12.4 summarizes the degradation sites and mechanisms, stressors, potential failure modes, and methods for inservice inspection of BWR recirculation piping. IGSCC is the primary degradation mechanism and has been the focus of mitigation efforts to this time. From the viewpoint of aging and license renewal, the areas of concern are (a) evaluating the long-term adequacy of the various mitigation measures developed for IGSCC degradation, (b) identifying potential areas of concern during extended operation associated with the various IGSCC remedies, and (c) evaluating the effect of degradation mechanisms other than IGSCC on residual life.

12.2 IGSCC Degradation

The materials used in fabricating BWR piping systems have mainly been Type 304 stainless steel and, to a lesser extent, Type 316 stainless steel. The occurrence of IGSCC in welded Type 304 stainless steel piping has been widely researched and is known to require the presence of three contributing factors:

- A sensitized microstructure
- A chemically aggressive environment that will support the occurrence of IGSCC
- A tensile stress in excess of the yield stress.

Sensitized Microstructure. Sensitization of the microstructure of austenitic stainless steel occurs when the material is exposed to temperatures between about 550 and 850°C (1020° and 1560° F) for certain minimum periods of time. This leads to precipitation of chromium carbide particles along the grain boundaries and a depletion of the local chromium content. Once the chromium content in the neighborhood of the grain boundaries falls below about 12%, the material becomes sensitized and susceptible to IGSCC.[8]

Sensitization usually occurs in the heat-affected zones (HAZs) produced during welding of susceptible stainless steel components. The areas adjacent to the weld are heated to or through the critical temperature range, and grain boundary chromium carbide particles precipitated during welding are found in these zones. A typical HAZ produced during welding is shown in Figure 12.1. Figure 12.2 is a time-temperature sensitization diagram showing the relative sensitization kinetics of Types 304, 316, and 316L stainless steel.[9] The curves show that sensitization of Type 304 stainless steel occurs within a few minutes at 700°C (1290°F), and that an equivalent sensitization is reached in Type 316 stainless steel after only about 30 minutes at 750°C (1380°F). The sensitization of Type 316L stainless steel is even slower, and this material is generally considered resistant to sensitization caused by normal air-cooled welding.

Table 12.4. Summary of degradation processes for BWR recirculation piping

Rank	Degradation Sites	Stressors	Mechanisms	Failure Modes	Method
1	Weld heat-affected zone, furnace sensitized safe ends	Tensile stress, oxygen environment, sensitized heat-affected zone	IGSCC	Cracks, Leaks	Ultrasonic examination, moisture-sensitive tape, acoustic emission
2	High thermal stress regions predicted by stress rule index analysis	Cyclic tensile stress, corrosive environment	Thermal fatigue, corrosion fatigue	Cracks, leaks	Ultrasonic examination, moisture-sensitive tape, acoustic emission
3	Austenitic-Ferritic stainless steel castings with high delta ferrite levels	High temperature, tensile stress, shock loads	Thermal embrittlement	Cracks, leaks	Ultrasonic examination, moisture-sensitive tape, acoustic emission

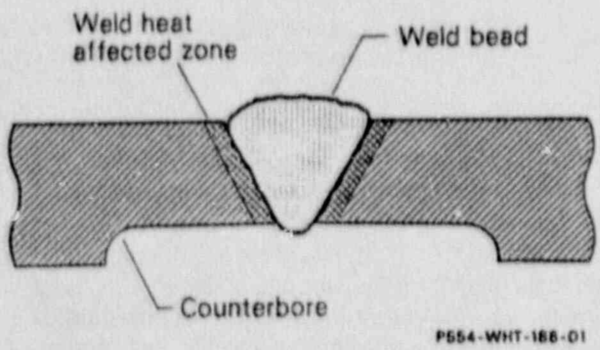

Figure 12.1. Cross section of weld heat-affected zone in BWR piping.

Since sensitization depends on both material and time-temperature history, the degree of sensitization depends on the welding process used during fabrication. The degree of sensitization also varies somewhat from heat to heat in Types 304 and 316 stainless steel. Several comparative methods have been developed to determine the degree of sensitization. These include a modified ASTM A 262, Practice A; a modified ASTM A 262, Practice E; and an electrochemical potentiokinetic reactivation (EPR) Test.[10] Experience has shown that intergranular cracking can occur even in moderately or slightly sensitized stainless steels subjected to a severe service environment and high stress levels. Therefore, calibration testing under actual or simulated service conditions is needed to establish the level of sensitization acceptable for a particular application.

Increased sensitization has also been observed to develop with time at temperatures below 500°C (930°F). This effect is called low-temperature sensitization (LTS)[11] and is caused by the low-temperature growth of the chromium carbide particles nucleated during welding. Carbide particles can be nucleated by brief exposure to temperatures in the sensitization range, which is not long enough to result in severe chromium depletion.[12] Once nucleated, these particles can grow at temperatures below 500°C (930°F). The chromium adjacent to the grain boundary is depleted as these particles grow, and susceptibility to IGSCC increases. The rate-controlling step for this process is the diffusion of chromium in solution in the matrix to the chromium carbide particles nucleated on the grain boundaries. The rate at which LTS occurs depends on a number of variables, including temperature and the degree of cold work (dislocation density) in the material. Present estimates are that LTS can occur at reactor operating temperatures in 10 to 20 years.[13,14] The uncertainty in estimating the rate at which LTS occurs under service conditions is due to both the material variability discussed above, and the fact that the estimated rate of LTS at reactor operating temperatures has been obtained from LTS heat treatments performed at higher temperatures.

There is evidence that IGSCC can also occur in BWR material that has not been sensitized. Crevices have acted as initiation sites for IGSCC in the BWR recirculation piping. Introduction of some crevices can be minimized by the use of proper welding procedures and by reduced grinding of the welded joints. However, crevices are sometimes inherent in piping or safe end design and cannot be minimized. Cold worked surfaces have also acted as initiation sites for IGSCC.

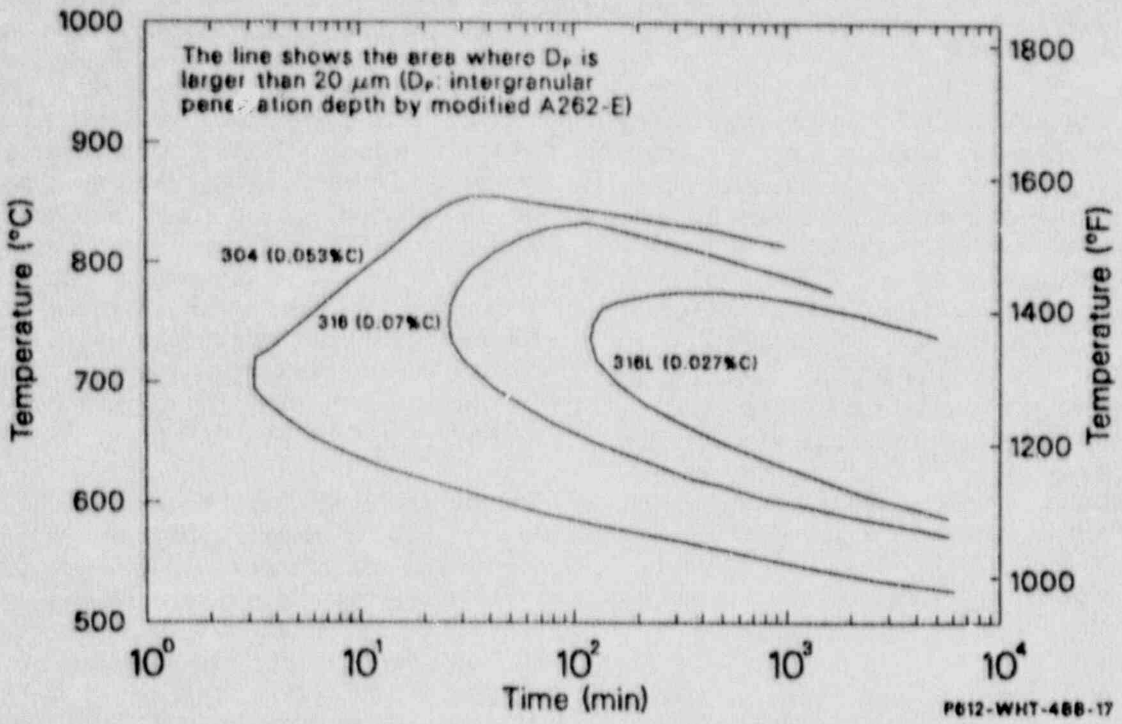

Figure 12.2. Relative sensitization kinetics of Types 304, 316, and 316L stainless steel.[9]

Laboratory tests show that IGSCC can occur in Type 316NG stainless steel that contains more than 5% cold work.[15] Peach Bottom 2 reported cracking in several jet pump inlet riser safe ends fabricated from Type 316L low–carbon stainless steel.[16] The cracks were found in the safe ends near the thermal sleeve attachment weld. Nondestructive and subsequent metallurgical examination revealed the presence of shallow intergranular stress corrosion cracks on both the creviced and noncreviced sides of the weld. The examination also revealed that the material was not sensitized, and the cracking on the noncreviced side had initiated at a surface that had been cold worked.

The welding alloys used to make nozzle–to–safe end welds are listed in Table 12.3 and include iron–base Type 308L weld metal, and nickel–base Alloy I–82 and Alloy I–182. Type 308L and Alloy I–82 are more resistant to IGSCC than Alloy I–182, but there is a serious concern regarding the long–term resistance of Alloy I–82.[17] No cracking has been observed in Type 308L or Alloy I–82 weld metals. However, in several cases the IGSCC cracks initiated in the heat–affected zone of recirculation inlet nozzle–to–safe end welds and propagated through Alloy–182 weld metal. Such cracking was first observed at the Duane Arnold BWR plant in 1978. In three different cases, such cracks have propagated through a portion of the nozzle's low–alloy steel base metal.[18] Such cracks are hidden behind the safe end nozzle welds and are difficult to detect. Weld overlay reinforcement may be used to repair these cracks and is discussed in Section 12.5.

Environmental Factors. The environment needed for IGSCC is provided by the BWR primary coolant, which in BWRs is high purity neutral water. Owing to radiolysis of the coolant in the core, a steady–state concentration of about 200 ppb dissolved oxygen and 20 ppb dissolved hydrogen is present in the coolant during full–power operation. This level of oxygen is sufficient to produce IGSCC in sensitized Types 304 and 316 stainless steel.

The oxygen concentration in the reactor coolant may approach 5000 to 8000 ppb before startup of reactor because of air ingress. A portion of the oxygen present in the reactor coolant then undergoes radiolytic conversion to hydrogen peroxide during the reactor startup. Hydrogen peroxide is a strong oxidizing agent and can also influence IGSCC cracking.[19] Deaeration of BWR coolant during startup reduces the oxygen concentration, and, therefore, the concentration of hydrogen peroxide. Thus, deaeration is partially effective in mitigating IGSCC. Determination of the relative influence of the startup versus steady state environmental conditions on IGSCC in service is difficult. Hydrogen peroxide decomposes into H_2O and O_2 above about 150°C (300°F), and, therefore, is not present in the reactor coolant at normal BWR operating temperatures [288°C (550°F)].

Ionic impurities in the BWR coolant also influence the IGSCC. The most important groups of ionic impurities are sulfates, chlorides, copper, and carbon dioxide.[20] The main source of sulfate impurities is the decomposition of any resin released from the demineralizer system to the coolant. The released resin decomposes in the coolant at temperatures above 60°C (140°F). Resin decomposition facilitates the formation of sulfuric acid, which lowers the pH and results in an increased electrochemical potential of the stainless steel piping. The change in pH and the duration of this change are related to the rate of resin release and decomposition into the coolant system.[21] Under a simulated BWR water chemistry [200 ppb O_2, 10 ppb H_2 at 288°C (550°F)], the addition of 0.1 to 1 ppm of sulfate appreciably enhanced the IGSCC susceptibility of sensitized Type 304 stainless steel.[20]

Leaking condensers have resulted in an increased concentration of chlorides in sea water-cooled BWR plants. Accidental intrusion of chlorinated hydrocarbons into the makeup water is also a source of chlorides in BWR water. Chlorides increase the conductivity of the coolant and also lower the crack tip pH and, thus, enhance crack propagation. The reactor coolant may also have high copper concentrations in plants having copper alloys in the feed water system. The presence of copper in a normal BWR environment enhances the corrosive effect of any chlorides. (The passivity of the stainless steel is decreased when copper is present in chloride solutions). In fact, an increase in the IGSCC susceptibility of sensitized stainless steel requires a higher concentration of chlorides than sulfates when copper is not present in the coolant.[20] The presence of hydrogen peroxide also enhances the effects of chlorides during BWR startup.

Carbon dioxide is another important decomposition product of the resin bed organic materials in the demineralizer systems. The coolant will also absorb carbon dioxide during refueling when the reactor is open to the atmosphere. However, only a marginal increase in IGSCC crack growth rate has been observed in specimens exposed to a simulated normal BWR water chemistry except for the addition of 1 and 10 ppm CO_2.[20]

Tensile Stress. The third contributing factor required for the occurrence of IGSCC is a tensile stress above the at-temperature yield stress. The yield stresses for Type 304 stainless steel at 24°C (75°F) and 280°C (536°F) are 255 MPa (37 ksi) and 160.6 MPa (23.3 ksi), respectively.[22] The piping systems in the early BWR plants were designed in accordance with the ANSI Code for pressure piping, B3.1. In the newer plants, the piping systems are designed in accordance with Section III of the ASME Boiler and Pressure Vessel Code for Nuclear Power Plant Components. The code requirements in both cases limit the design stresses in the piping systems to values less than about 60% of the material yield stresses.[1] However, the codes do not consider the effects of fabrication, fit up, and welding. The resulting stresses, called residual stresses, in the heat-affected zone at the inside surface of the pipe, are tensile, and may be higher than the yield stress of Type 304 stainless steel.

The peak axial residual stress is on the inside surface in the heat-affected zone, and its magnitude deceases as the pipe diameter increases. In addition, the axial residual stress on the inside surface gradually changes from tensile to compressive as the distance from the weld fusion line increases. The distribution of the through-wall residual stresses depends on the pipe diameter and wall thickness, and the distribution is not necessarily azimuthally uniform. For example, measurements of axial residual stresses in the heat-affected zone at the inside and outside surfaces of three different sizes of welded Type 304 stainless steel pipes are listed in Table 12.5.[7] All three pipes have relatively large tensile stresses at the inside surface; however, the two larger pipes have relatively small tensile stresses at the outside surface. Field data indicate that the distribution of residual stresses is permanent, that is, it does not change with time in operation.

12.3 Non-IGSCC-Related Degradation

Several degradation mechanisms other than IGSCC may affect the life of the BWR recirculation piping systems. These include transgranular stress corrosion cracking, crevice corrosion, thermal aging of cast stainless steel components, and fatigue. These degradation mechanisms have not yet caused significant problems in recirculating piping systems and consequently have not been the subject of large-scale research and development efforts. However, there is ongoing work in these areas that has helped to define potential problem areas and possible mitigation measures.

Transgranular stress corrosion cracking (TGSCC) occurs in austenitic stainless steels subjected to high stress levels and aggressive environments. TGSCC has been observed in Types 316NG and 347NG

Table 12.5. Axial residual stresses in the heat-affected zones on the inside and outside surfaces of welded Type 304 stainless steel pipe

	Residual Stresses			
	Inside Surface		Outside Surface	
Pipe Size [mm (inch)]	Distance from Weld Centerline [mm (inch)]	Stress [MPa (ksi)]	Distance from Weld Centerline [mm (inch)]	Stress [MPa (ksi)]
100 (4)	5 (0.20)	359 (52)	—	—
254 (10)	5 (0.20)	276 (40)	15 (0.6)	48 (7)
660 (26)	5 (0.20)	200 (29)	8 (0.32)	69 (10)

stainless steel replacement materials during laboratory tests with environments containing sulfates.[23] Transgranular cracking has also been observed in reactors as a result of chloride intrusion. And, TGSCC has been observed in laboratory tests with highly stressed and cold worked surface specimens.[15] To prevent transgranular cracking, it is important to maintain a high purity water chemistry and minimize cold work during fabrication. In particular, postweld grinding of the inside surface of the weldments should be avoided since this causes severe cold working of the surface. Finally, laboratory tests have shown that transgranular stress corrosion crack growth will stop when the specimen is exposed to low dissolved–oxygen environments, indicating that the adoption of hydrogen water chemistry (discussed in Section 12.4) may mitigate this degradation mechanism.[24]

The recirculation piping systems contain components such as elbows, valve bodies, and pump bodies which are fabricated from Grades CF8 and CF8M cast stainless steel. The cast stainless steels have a duplex structure with ferrite contained within an austenitic matrix, have good mechanical properties, and are resistant to IGSCC. However, the cast stainless steels are susceptible to embrittlement at elevated temperatures [~400°C (~750°F)] and testing has shown that they are also susceptible to long–term embrittlement (thermal aging) at LWR temperatures.[25,26] Thermal aging causes an increase in the hardness and tensile strength and a decrease in the ductility and fracture toughness. The effect is most severe in castings with high ferrite levels.

Although the relative degree of thermal aging and embrittlement of the cast stainless steels can be quite high, it is not clear that the plant design margins are impacted, since these materials still retain considerable toughness after aging. An analysis of the thermal aging of pump casings shows that large flaws and high stresses can be tolerated even after considerable time.[26] Similar assessments are needed for the other components affected by this degradation mechanism. The information would provide a basis for establishing minimum acceptable flaw sizes and improved inservice inspection requirements.

The fatigue life of the recirculation piping system is affected by the thermal transients that occur during the operation of the plant. Mechanically and flow–induced vibrations also affect the fatigue life. The critical areas in the recirculation piping system are the welded joints, particularly in locations where there are geometrical or material discontinuities that result in stress risers. However, fatigue does not appear to be a life limiting degradation mechanism in the recirculation piping and there have been no recirculation piping fatigue failures.

12.4 Remedies for Pipe Cracking in BWRs

The mitigation and repair of the IGSCC of the BWR piping has received considerable attention from both industry and the NRC. This work has provided a technical basis for interim operation with cracked or repaired piping and has also provided engineering solutions for the long–term mitigation of IGSCC in BWR piping systems.

The countermeasures developed for pipe cracking involve a reduction of the severity or elimination of one or more of the three conditions discussed above, namely,

1. Use of materials and processes that minimize sensitization

2. Reduction of the tensile stresses at the inner surfaces of the piping in the heat-affected zones

3. Modifications of the BWR water chemistry to reduce the electrochemical potential and conductivity, which are known to enhance the susceptibility of stainless steel to IGSCC.

Alternate materials and processes are now available to minimize or eliminate sensitization in the piping systems. Several stress-related remedies that reduce the residual stresses in the welded piping have been qualified. Finally, the use of hydrogen water chemistry results in an operating environment less severe in terms of IGSCC than that resulting from the normal BWR water chemistry. The following subsections discuss the methods developed for the mitigation and the repair of IGSCC pipe cracking.

Materials–Related Remedies. A number of materials-related remedies have been developed for mitigation of IGSCC in BWR stainless steel piping systems. These remedies are based on minimizing or eliminating the sensitization that occurs in austenitic stainless steel caused by chromium depletion at the grain boundaries. The remedies now available are solution heat treating, use of corrosion resistant cladding, and use of IGSCC resistant alternate alloys.

Solution heat treating is a standard fabrication procedure used to protect against sensitization of welds in Type 304 stainless steel.[27] This process involves heating the fabricated component to above 1000°C (1832°F) to redissolve the carbide particles precipitated during welding. The heated piece is then rapidly water-quenched to prevent nucleation of carbide precipitates. Welds protected by the corrosion-resistant cladding should be inspected per ASME Code Section XI.[28]

Solution heat treating eliminates weld sensitization and the residual stresses produced during welding and machining operations. However, solution heat treatment is only practical for shop welding, and properly qualified procedures must be used for heating and quenching the part being treated. The water quench can be difficult to perform for large components or components with complex shapes, and it can produce high residual stresses. No problems with IGSCC are anticipated in those cases where solution heat treating is used. At present, approximately 40% of the welds in a recirculation piping system are solution heat treated. Twenty-five percent of the weldments treated by solution heat treatment are required to be inspected during each 10-year interval, as per ASME Code Section XI.[28]

A second remedy developed for Type 304 stainless steel piping is the application of *corrosion-resistant cladding* to the inner surface.[26,27] The remedy involves the application of at least two layers of Type 308L weld metal to provide a protective cladding on the inside surface of the piping. The cladding should have a minimum thickness of 3.2 mm (0.125 in.) and a minimum ferrite content of 8% by volume.[29] This material has been found to be very resistant to IGSCC in a BWR environment because it has a duplex austenite–ferrite grain structure.[30] Precipitation of the chromium carbide particles occurs along the austenite–ferrite grain boundaries, not along the austenite–austenite grain boundaries, because the chromium diffusion rate is much faster in the ferrite phase than in the austenite phase. A detailed description of the mechanism and the critical amount and distribution of ferrite required to inhibit IGSCC is provided in References 30 and 31.

Two versions of the corrosion-resistant cladding remedy have been developed. One is a shop application that includes solution heat treating (as discussed above) after a partial cladding application. This step eliminates the sensitization of the heat-affected zones exposed to the coolant. A second version is a field application that does not include solution heat treating. In this procedure, a layer of corrosion-resistant cladding is applied to the inside surface of the piping in the region adjacent to the joint to be welded. This causes a small area of the heat-affected zone at the ends of the weld to be left on the inner surface exposed to the coolant. However, it is limited in depth and is not located in the region of maximum weld-induced stress. Figure 12.3 shows the sequence of fabrication steps and the location of the heat-affected zones for the two corrosion-resistant clad procedures.[30]

The shop procedure starts with a partial application of cladding to the pipe inside surface near the joint to be welded. The piece is then solution heat treated to eliminate the weld-sensitized zone adjacent to the weld deposit. After the solution heat treatment, the remainder of the corrosion-resistant cladding is applied to the inner surface of the pipe. As can be seen in Figure 12.3, the heat-affected zone produced by this process does not extend to the piping inside surface in contact with the reactor coolant. The qualification tests on these two processes indicate that both will provide IGSCC resistance for BWR piping systems.[32]

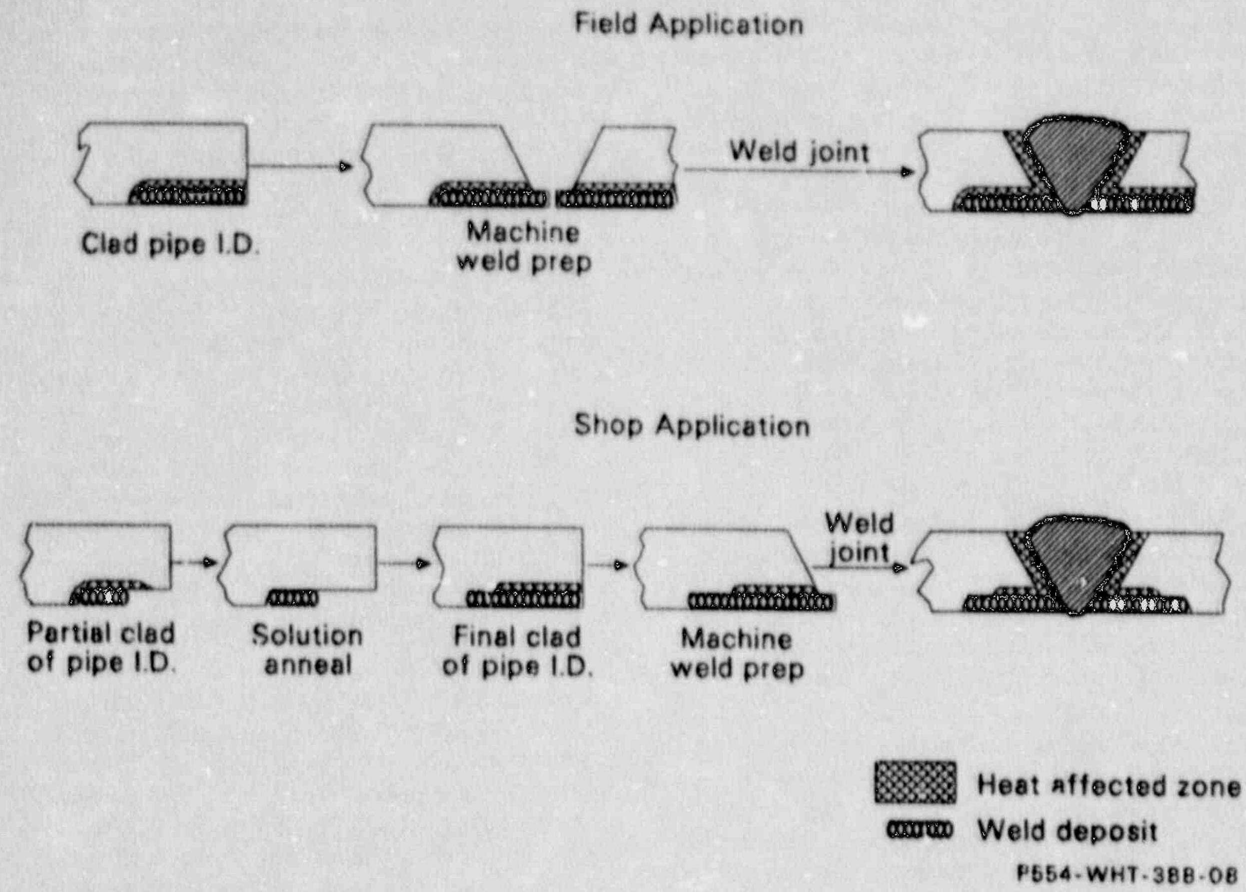

Figure 12.3. Sequence of fabrication steps and locations of heat–affected zones for welds protected by two corrosion–resistant cladding procedures.[30]

Several *alternate materials* have also been qualified for use in BWR piping. These alloys are resistant to IGSCC in normal BWR environments since they do not sensitize during welding. Nuclear grade Types 304 and 316 stainless steel were developed as replacement materials for domestic reactors. These alloys, labeled Types 304NG and 316NG, are not sensitized during welding because of their low carbon content (0.020% max). Since the low carbon content acts to reduce the yield strength, compensation for the reduction in carbon content is provided in the nuclear grade material by an increase in the nitrogen content, which is maintained between 0.060 – 0.10%. This results in yield strengths within the original piping design requirements. Type 316NG stainless steel has been favored as a replacement material in domestic units; however, it does not have the same weldability as Type 304 stainless steel, and there have been welding problems with the Type 316NG.

Although Types 304NG and 316NG stainless steel appear to provide acceptable performance in normal BWR environments, constant extension rate tests have shown that Type 316NG is susceptible to transgranular stress corrosion cracking (TGSCC) when subjected to oxygenated environments containing chlorides and sulfates.[24] Cracking was observed in oxygenated water (0.25 ppm, O_2) containing 0.1 ppm H_2SO_4. This sulfate level is much higher than normally found in BWRs but is within the water chemistry limits allowed by Regulatory Guide 1.56. TGSCC is considered much less likely than IGSCC. However, after extended use, piping integrity might be affected by transgranular cracking if the water chemistry is not strictly controlled.[24]

Recently, Type 347 stainless steel has been considered because of difficulties experienced in welding the high–purity nuclear grade alloys. Type 347 alloy is a stabilized stainless steel containing carbide forming elements, such as niobium, to reduce the free carbon content. The carbide forming temperatures for the stabilizing elements are higher than those for chromium. Therefore, sufficient care should be taken during heat–treatment of Type 347 stainless steel to avoid precipitation of chromium carbide, which will again make the steel susceptible to IGSCC.[33] Initially, Type 347 stainless steel was not considered for domestic use because of unfavorable experience in the United States in the early 1960s with both fabrication and welding. Those problems were overcome by changes in the chemistry balance of the alloy and development of suitable welding processes. This material is used extensively in Germany, and a low-carbon niobium-stabilized Type 347 stainless steel has been used by the Kraftwerk Union for BWR piping. This piping has been in service for up to 20 years, and no occurrence of IGSCC has been reported. A modified version of this alloy is currently being considered for domestic use.[34,35] The modified alloy, Type 347NG, is stabilized with niobium and has a maximum limit on carbon of 0.02%.

Cast austenitic stainless steel with less than 0.035% carbon and a minimum of 8% (volume) ferrite is resistant to sensitization,[28] and may be used, if qualified, as an alternate material for BWR piping. At present, this material is not used as an alternate material for recirculation piping in United States BWR plants.

Stress-Related Remedies. A number of stress-related remedies have been developed for the mitigation of IGSCC. These remedies include heat-sink welding, induction-heating stress improvement, and mechanical stress improvement. These remedies reduce the residual tensile stresses in the weld heat-affected zone (HAZ), and, in most cases, compressive residual stresses are produced on the inside surface of the piping, which extend part way through the wall. The tensile stress condition necessary for the initiation of IGSCC is mitigated by these remedies, and the propagation of existing cracks will be arrested when the crack tips are kept in compressive stress.

Heat-sink welding is a process that can be used in the initial welding of new piping or for complete rewelding of an existing joint. With this process, the initial sealing passes (the root pass and several additional passes) are made in the conventional way. Subsequent welding passes are made with the inside surface of the piping cooled by either a water spray or flowing water. The thermal gradients generated during heat-sink welding produce residual compressive stresses on the inside surface of the welded joint. For example, the heat-sink welding process introduced a residual axial compressive stress of 600 MPa (87 ksi) in the heat-affected zone on the inside surface of a 250-mm- (~10-in.-) diameter pipe-to-pipe weldment, as compared to a residual axial tensile stress of 138 MPa (20 ksi) in a conventional weldment.[36] A comparison of the circumferential residual stresses left after heat-sink welding with those left after conventional welding is shown in Figure 12.4. As indicated by Figure 12.4, heat-sink welding produces residual stresses at the inside surface which were compressive in all pipes tested [200 mm (8 in.) in diameter and larger].[37] However, implementation of heat-sink welding presents some problems with respect to both the heat sink-weld sequencing and the structural support (because of the weight of water).

The heat-sink welding process also results in reduced sensitization of the weld HAZ. The water cooling acts to reduce the size of the HAZ and to reduce the degree of sensitization because of the rapid cooling of the pipe between weld passes. This effect may be partially offset by low-temperature sensitization, which has been observed in laboratory studies of weld HAZs produced by heat-sink welding.[14] Although low-temperature sensitization can enhance the sensitization of the heat-affected zones, it will not affect the compressive stress produced by this process, and there should be no increase in the susceptibility of these welds to IGSCC.

A second method, the *induction-heating stress-improvement method* (IHSI) was originally developed in Japan and has been the most widely implemented stress improvement method to date.[38] This method has the advantage of being used after the conventional welding process is completed. The IHSI process consists of heating the finished pipe welds using an induction coil located around the weld while the inner surface is cooled by flowing water. The IHSI process is shown schematically in Figure 12.5. The outside surface of the weldment is heated to about 500°C (932°F) while the inside surface is maintained near 100°C (212°F). The steep thermal gradient causes the outer surface to yield in compression and the inner surface to yield in tension. After cooldown, the relative contraction of the piece being treated causes the stress field to reverse, placing the outside surface in tension and the inside in compression. Figure 12.6 shows an example of the through-wall axial residual stresses produced by the IHSI process when applied to a 410-mm (16-in.-) diameter pipe. The residual compressive stress level on the inside surface, shown in Figure 12.6, is 300 MPa (43 ksi), which is typical of the range achieved with this treatment, about 205 to 345 MPa (30 to 50 ksi). The IHSI treatment produces a compressive residual stress that extends from the inside surface through more than 50% of the wall. The residual compressive stress level at the inside surface is generally above about 205 MPa (30 ksi), the minimum specified 0.2% offset yield stress for Types 304 and 316 stainless steel. The residual tensile stress level on the outside surface is about 360 MPa (52 ksi) which is significantly higher than those listed in Table 12.5 for the as-welded pipe.

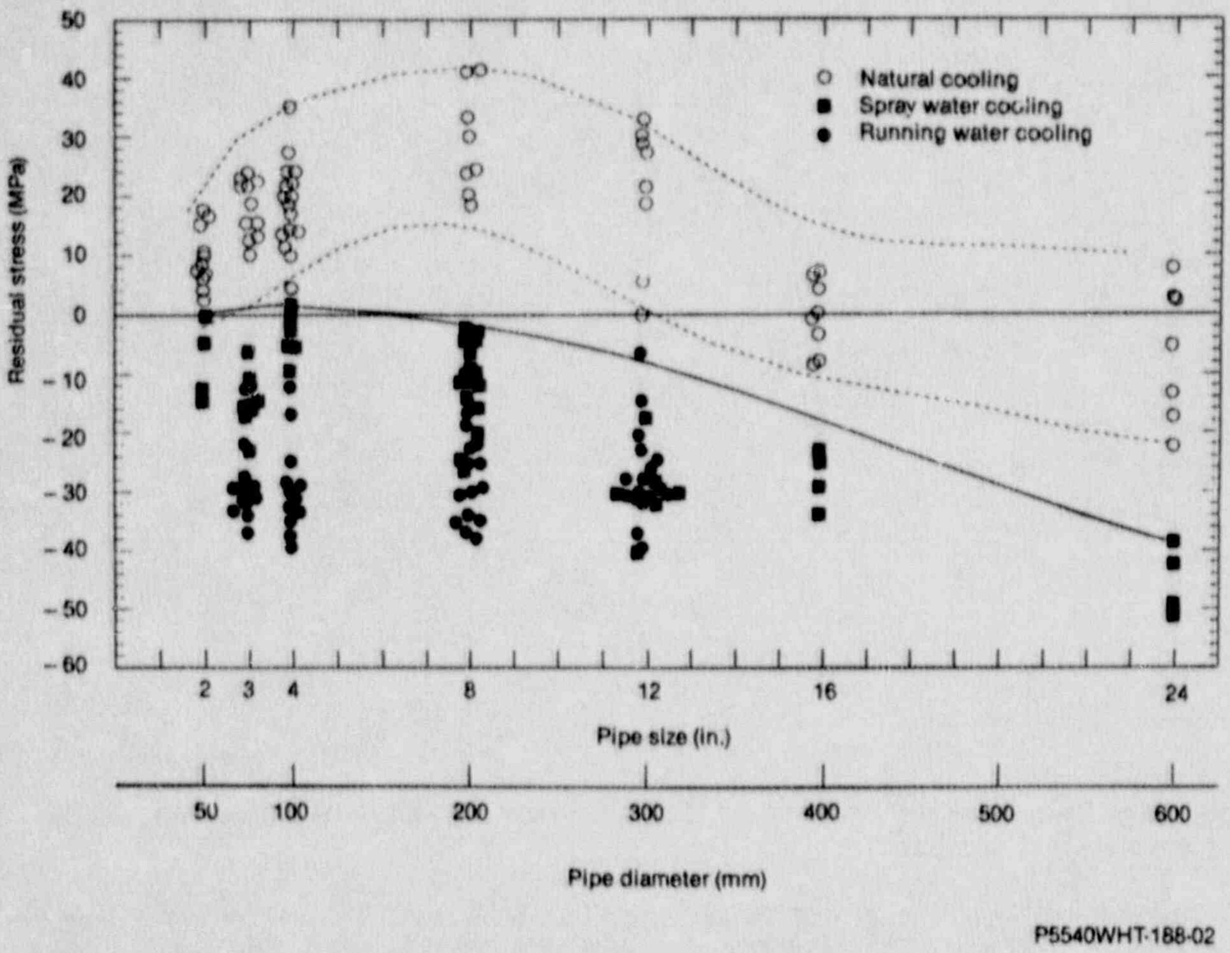

Figure 12.4. Circumferential residual stress in HAZ [3 mm (0.12 in.) away from fusion line] on the inside surface of various diameter Schedule 80 pipe welds.[37] 1 MPa = 0.145 ksi.

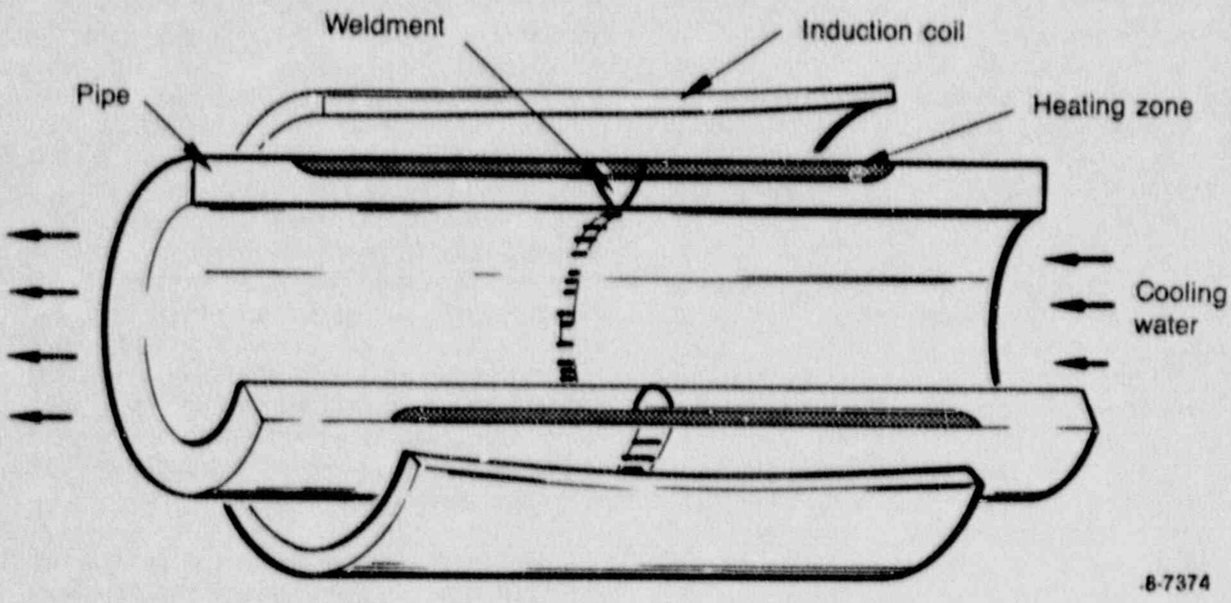

Figure 12.5. Outline of induction–heating stress–improvement process.[10]

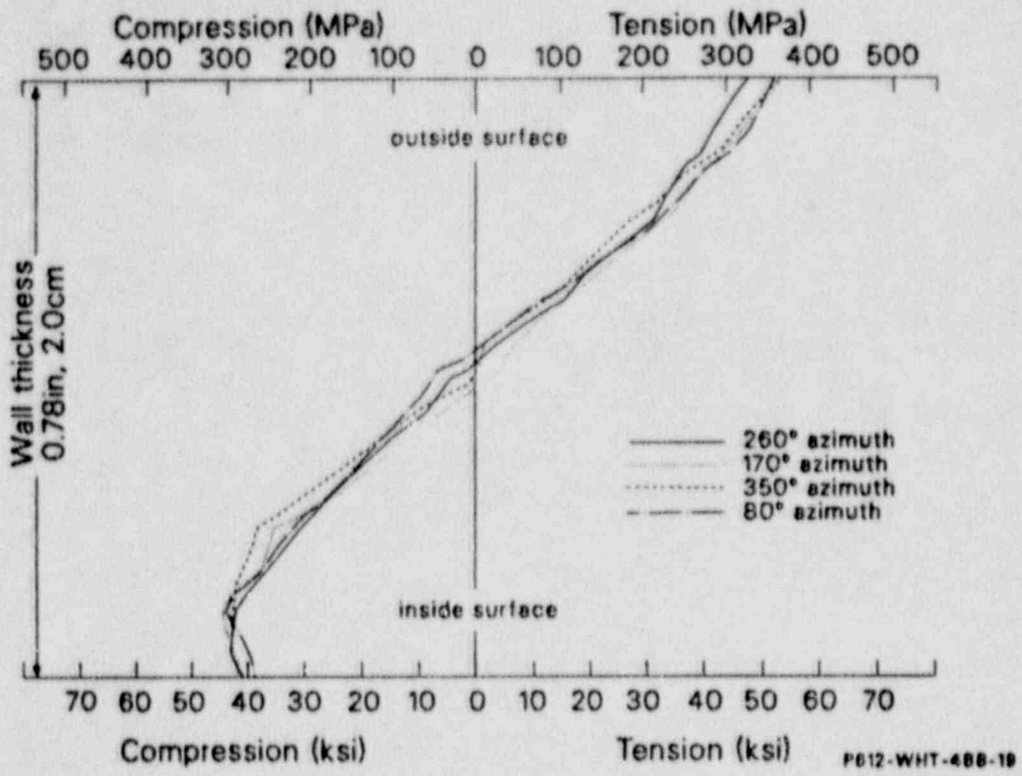

Figure 12.6. Through–wall axial residual stress 0.25 cm (0.1 in.) from fusion line, in a 410–mm (16–in.) diameter pipe, welded and IHSI processed.[38]

The conventional IHSI process cannot be applied to the heat–affected zones in the weldments between the reactor pressure vessel nozzles and the safe ends because the thermal sleeves make it impossible to properly cool the inside surfaces of the safe ends with running water. Therefore, a special nozzle has been designed to inject water into the annulus between the thermal sleeve and safe end. Laboratory tests on mock–ups simulating the actual nozzle–safe end connection show that the modified IHSI using the special nozzle is effective in producing compressive residual stresses in the heat–affected zone on the inside surface of the safe end.[39]

An extensive testing program has been carried out to investigate the IGSCC resistance produced by the IHSI process.[38] The results of the testing program show that the IHSI remedy produces IGSCC–resistant welds which can accommodate applied stresses of up to about 207 MPa (30 ksi), which is above the normal service levels. Work on precracked piping shows that the IHSI remedy produces a strong compressive residual stress on cracks extending through less than 40% of the wall. The compressive residual stress should prevent or slow down further crack growth. Tests have also been run on precracked pipes subjected to high applied loads that produced tensile stresses at the existing crack tips. The results from those tests show little or no benefit from the IHSI treatment.

With regard to the long–term effectiveness of the IHSI process, a number of factors have been evaluated. Applied load induced relaxation of the residual stress has been investigated.[40,41] The results suggest that the primary stress levels anticipated during BWR operation will not cause relaxation of the residual stresses. Low–temperature sensitization of the ISHI–treated zone has also been studied.[14] This was considered potentially important since the IHSI process produces a favorable residual stress state by thermomechanically working a large region on either side of the weld. The thermomechanical working is accompanied by an increase in the dislocation density in the material, which is a factor known to increase the tendency for low–temperature sensitization. The results of this study show that the sensitized region in the weld HAZ becomes somewhat larger with time. However, the observed increase is not large and is the same both with and without application of the IHSI remedy.

A third stress improvement method, just recently developed, is the *mechanical stress improvement process* (MSIP) developed by O'Donnell and Associates, Inc.[42] The process employs a mechanical clamping technique to apply a compressive load on the pipe at some distance from the weld. The load imposed by the clamp then creates compressive stresses on the inside of the pipe over a region that includes the weld and HAZ. The application of the mechanical stress improvement process is shown in Figure 12.7.

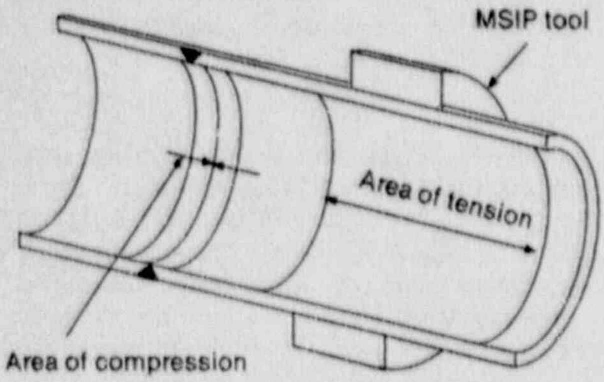

Figure 12.7. General view of the MSIP process.[44]

Examples of measured residual stresses in the heat-affected zones of three different weldments subjected to the MSIP process are discussed below.[43] The measured axial and circumferential compressive stresses on the inside surface of a 305-mm- (12-in.-) pipe-to-pipe weldment at 15 mm (0.59 in.) from the weld center line after the application of the MSIP were, respectively, 241 and 228 MPa [35 and 33 ksi (toward the MSIP tool)], and 331 and 214 MPa [48 and 31 ksi (away from the MSIP tool)]; the axial tensile stress on the outside surface at 15 mm (0.59 in.) from the weld center line was 186 MPa [27 ksi (toward the MSIP tool)]. The maximum measured axial residual stresses in a 711-mm- (28-in.-) pipe-to-pipe weld before and after the application of MSIP were, respectively, 138 and -276 MPa (20 and -40 ksi) on the inside surface, and -138 and 138 MPa (-20 and 20 ksi) on the outside surface. The level of measured axial residual stresses on the inner surface of a 356-mm- (14-in.-) pipe-to-elbow weld was 276 MPa (40 ksi) before the application of MSIP and in the range of -69 to -131 MPa (-10 to -19 ksi) after the application. The measured residual tensile stresses on the inner surface of the 711-mm- (28-in.-) pipe-to-elbow weld, under the MSIP tool and at a distance of 122 mm (4.8 in.) from the weld centerline, before and after the MSIP treatment, were 55 MPa (8 ksi) and 110 MPa (16 ksi), respectively.[44]

Last-pass heat-sink welding is a process (similar to the heat-sink welding discussed above) that uses thermomechanical work to reduce the IGSCC susceptibility of a finished joint. The welds are made in the conventional manner, and then a final pass is made using a high-heat input with no filler material. The inside of the pipe is water-filled during the last pass to provide a heat sink. This process has the advantage that it can be used during the initial welding of the piping, and it can also be used on piping with completed welds. The last-pass heat-sink welding process introduces compressive and tensile residual stresses, respectively, in the heat-affected zones on the inside and outside surface of a weld. For example, this process introduced axial residual stresses of magnitude -262 MPa (-38 ksi) and 69 MPa (10 ksi) in the heat-affected zones on the inside and outside surface, respectively, of a 610-mm- (24-in.-) diameter Type 304 stainless steel pipe-to-pipe weld.[7] The last-pass heat-sink welding process has been further developed in recent years and it now produces higher and more reproducible residual compressive stresses.[40,44] However, the process has not yet been qualified, and at this time is not considered to be a fully effective remedy for IGSCC.[28]

Inservice inspection requirements for the weldments on which stress improvement is performed and in which no cracks have been detected during the subsequent required inspection, are as follows.[28] If stress improvement is performed within two years of operation, 50% of the welds should be examined during each 10-year interval. If stress improvement is performed after two years of operation, the welds are more likely to contain undetected cracks; and all the affected welds should be inspected within two refueling cycles, and every ten years thereafter.

The IHSI and MSIP processes produce residual tensile stresses on the outside surface of the piping in the heat-affected zone, and are much larger than those in the as-welded pipe. Therefore, any IGSCC that initiates from the outer wall is a potential concern, particularly if corrosive agents such as chlorides and sulfates are present. This concern can be minimized by careful control of the materials that contact the piping (such as insulation), and by control of the environments within the containments and reactor buildings.

Hydrogen Water Chemistry. As discussed above, radiolysis of the BWR coolant produces free oxygen and hydrogen during reactor operation. Most of the free hydrogen and oxygen are mixed with the steam and are subsequently removed from the coolant loop at the condenser. However, about 200 ppb O_2 and 20 ppb H_2 remain in the primary coolant water during steady-state full-power operation. The objective of hydrogen water chemistry (HWC) is to reduce the electrochemical potential of the stainless steel piping and fittings by injecting hydrogen into the feedwater. The hydrogen is injected through taps in either the suction line leading to the condensate booster pump or to the main feedwater pump. The amount of hydrogen required in the feedwater depends on plant design. The hydrogen added to the primary coolant recombines with the radiolytically produced oxygen, reducing the oxygen level in the coolant and the corrosion potential of the stainless steel piping. However, at the residual oxygen levels achievable in BWRs, IGSCC is suppressed only at very low levels of ionic impurity, which controls coolant conductivity. Therefore, the HWC treatment developed for BWRs combines suppression of electrochemical potential with strict control of the water conductivity.

A series of laboratory tests have been performed to investigate the mitigation of IGSCC by oxygen suppression.[45-47] These tests included electrochemical potential and dissolved oxygen measurements, constant extension rate tests on small specimens, and tests using welded joints made from 10-cm (4-in.) Schedule 80 Types 304 and 316NG stainless steel piping. The tests demonstrate that IGSCC mitigation is possible at dissolved oxygen levels below 20 ppb when the conductivity is kept below 0.2 μS/cm. HWC is not effective unless appropriate water quality is maintained. Specifically, such impurities as sulfates, chlorides, and carbonates must be strictly controlled to maintain low conductivity levels. Maintaining a low conductivity level limits the general level of ionic impurities in the coolant. For example, a limit of 0.2 μS/cm corresponds to a limit of 0.02 ppm H_2SO_4. The laboratory studies show that HWC suppresses stress corrosion crack initiation and that HWC can prevent further growth of existing IGSCC cracks.

Electrochemical potential and dissolved oxygen measurements were used to determine how a given decrease in dissolved oxygen (under the expected range of HWC conditions) affects the corrosion potential of Type 304 stainless steel. The electrochemical potential or corrosion potential is a measure of the thermodynamic driving force for corrosion reactions. The measurements were made with Type 304 stainless steel in high-purity water and sodium sulfate solutions at various concentrations of dissolved oxygen and hydrogen. The results are presented in Figure 12.8, which shows a rapid drop in the electrochemical potential of Type 304 stainless steel as the dissolved oxygen drops to between 10 and 40 ppb. The figure also shows the results of electrochemical potential measurements made at Dresden 2, Peach Bottom 3, and Ringhals 1. Also shown in the figure is the protection potential determined from constant extension rate testing on small specimens. These tests show that reducing the corrosion potential to below $-0.230V_{SHE}$ (standard hydrogen electrode) mitigates IGSCC in sensitized stainless steel.

In addition to the tests on austenitic stainless steel, laboratory tests under simulated HWC conditions were run on other BWR structural materials, including Alloy 600, Alloy X-750, carbon steel, and Zircaloy 2. The additional testing on BWR structural materials has shown a generally beneficial effect. For example, HWC mitigates IGSCC of highly sensitized Alloy 600 and in Alloy X-750, and TGSCC of low alloy steel. However, the general corrosion and material removal rate of carbon and low-alloy steel was found to be significantly higher when using HWC.[46,47] Figure 12.9 shows the general corrosion rates measured in carbon steel both in an HWC environment and a reference environment containing 200 ppb O_2. The HWC corrosion rate is significantly higher than the reference environment corrosion rate during the first eight months of testing. Short-term results show that the steady-state general corrosion rates measured after a stable corrosion film was established are only slightly higher than in the reference environment. The erosion-corrosion of BWR feedwater and main steam systems is discussed in Chapter 10 of this report.

In addition to the laboratory tests, the results of short-term demonstration tests at Dresden 2 and Ringhals 1 have been reported.[28,48-50] Hydrogen was added to the feedwater to reduce the oxygen concentration in the recirculation water, and constant extension rate tests (for IGSCC) were used to evaluate the effectiveness of adopting HWC in an operating plant. The electrochemical potentials were also monitored during these demonstration tests. It was found that maintaining the oxygen level between 15 and 20 ppb was adequate to suppress IGSCC at Dresden. However, IGSCC was not suppressed at Ringhals until the residual oxygen level was reduced to below 10 ppb. The results of the electrochemical potential measurements at both Dresden 2 and Ringhals 1 show that resistance to IGSCC was achieved at corrosion potentials corresponding to the protective potential determined by the laboratory testing (Figure 12.8).

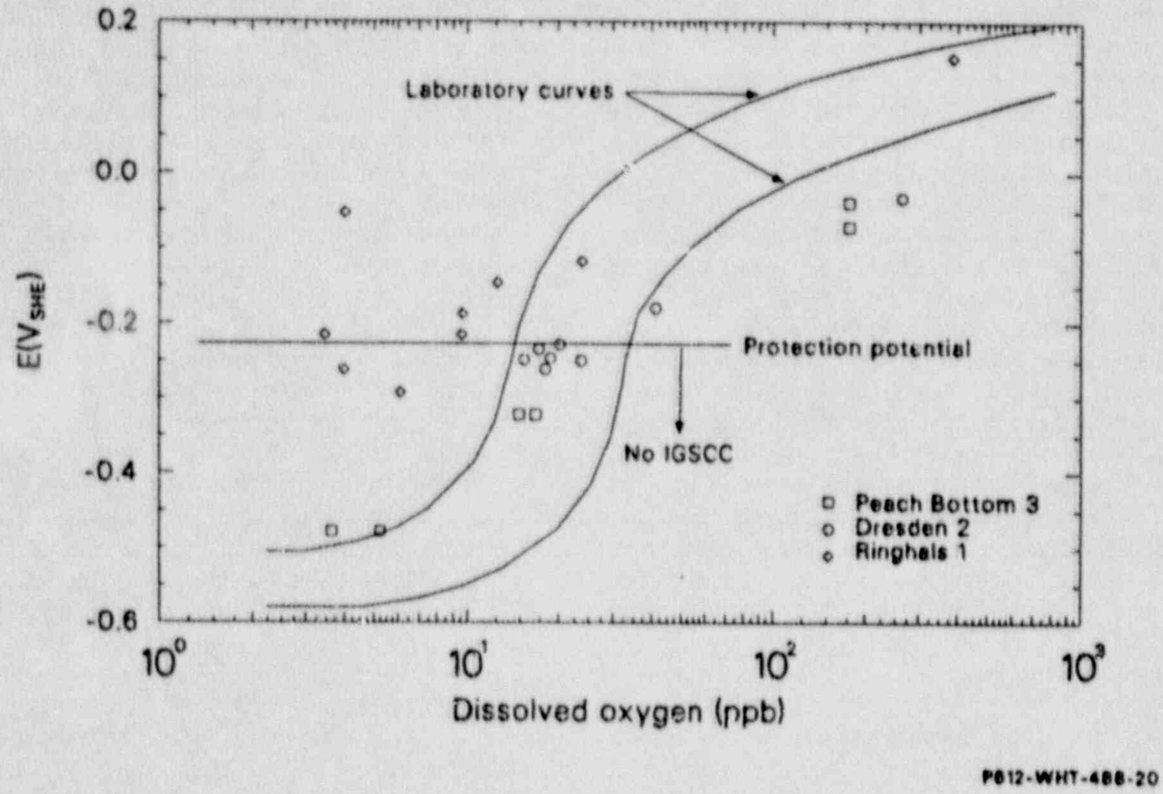

Figure 12.8. Electrochemical potential versus dissolved oxygen for Type 304 stainless steel (some in-reactor measurements are included).[47]

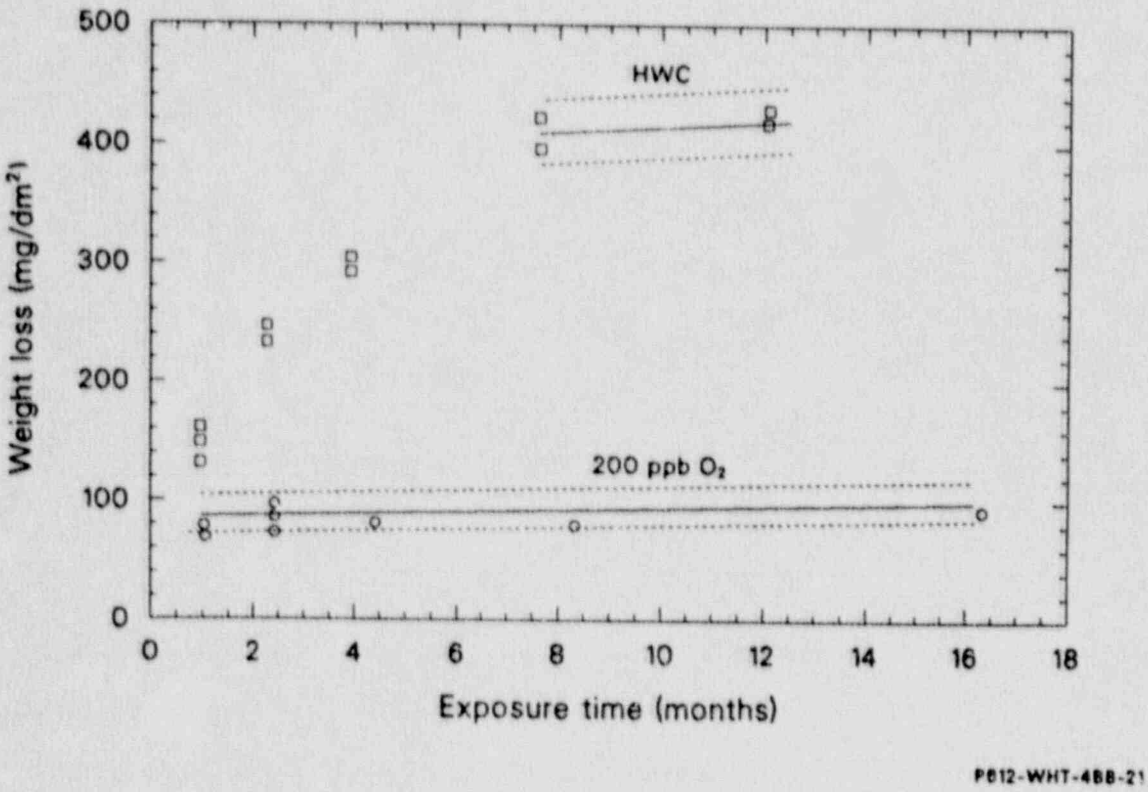

Figure 12.9. Corrosion of carbon steel in hydrogen water chemistry and reference environments.[47]

The experience at Dresden and Ringhals shows that plant-to-plant differences are also to be expected in implementing HWC. These differences are attributed both to plant design and materials. Recombination was found to be more complete in Ringhals 1, and for a given oxygen concentration in the recirculation system a lower hydrogen concentration was present.[49] Other experience has also shown that individual plants respond differently to HWC. Short-term tests have been run in Pilgrim, Fitzpatrick, and Peach Bottom 3.The oxygen concentration in the recirculation water of these three BWRs and Dresden 2 is shown in Figure 12.10 as a function of the hydrogen concentration in the feedwater.[51,52] The arrows in this figure indicate the hydrogen additions which are needed to reduce the electrochemical corrosion potential below the IGSCC limit. Hydrogen addition decreases the concentration of oxygen in the recirculation water in all plants; however, the amount of decrease is plant dependent, and reasons for this are not known at present.[52] At present, HWC has been implemented in six domestic BWR plants.

Following the demonstration test in Dresden 2, HWC was implemented in Dresden 2 on a long-term basis, starting with Cycle 9 (April 1983). The improvement of water quality at Dresden 2 was accomplished with existing equipment during Cycle 9. Key changes in operating practices that improved the water quality were the use of new condensate resins, a switch to stoichiometric equivalent resin mixtures, termination of resin regeneration, and elimination of resin recycling from radwaste to condensate system.[53] The results reported after the first 18-month fuel cycle with HWC are quite positive. At full power, the oxygen levels in the recirculation piping were maintained below 20 ppb by a concentration of 1.32 ppm dissolved hydrogen in the feedwater. During the last 12 months of Cycle 9, the oxygen concentration in the recirculation piping was kept below 20 ppb about 78% of the time, and the water conductivity was kept below 0.20 μS/cm 98.9% of the time. The oxygen concentration during Cycle 10 was below 20 ppb about 82% of the time, slightly higher than the 78% obtained during Cycle 9. The conductivity of the recirculation water was less than 0.2 μS/cm for greater than 99% of the time during Cycle 10. The recirculation water pH in Cycle 10 was slightly acidic, compared to slightly basic values in Cycle 9.[53] One of the important results from the Dresden full-scale demonstration has been to

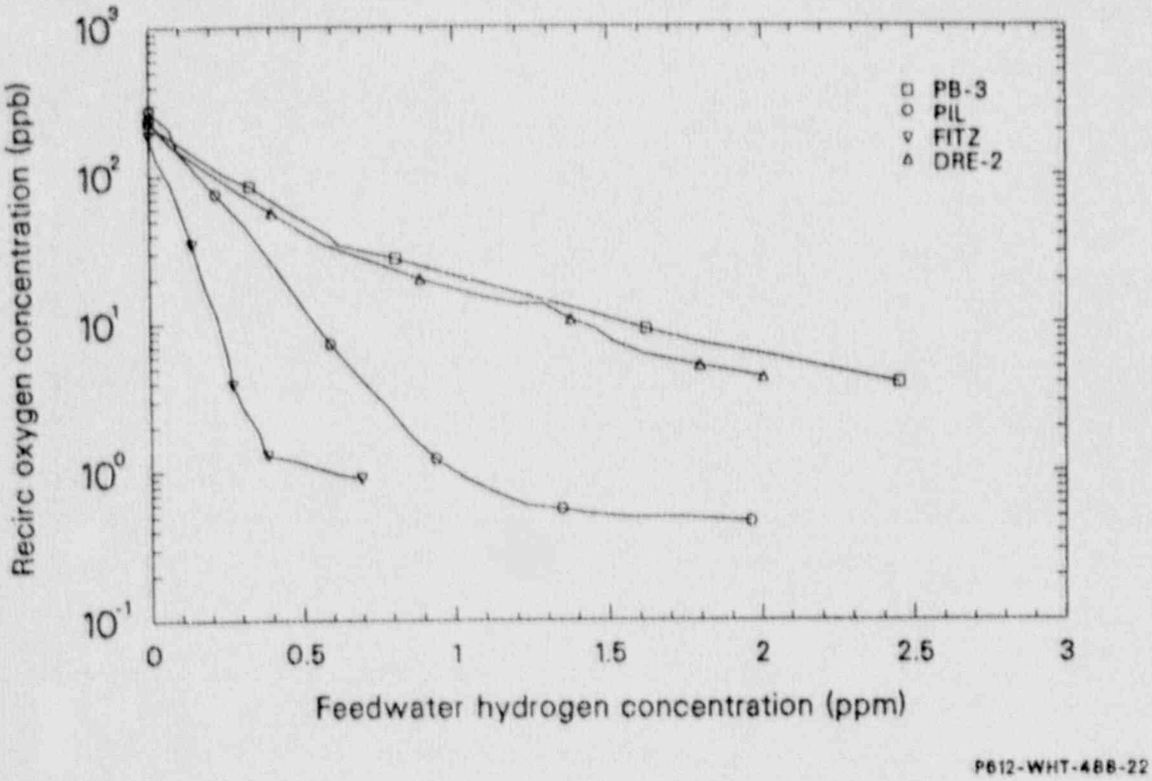

Figure 12.10. Recirculation line oxygen concentration as a function of feedwater hydrogen concentration for four U.S. plants. (The arrows indicate addition rates that depressed the stainless steel corrosion potential below the IGSCC protection potential.)[52]

show that the HWC requirements do not need to be met 100% of the time to suppress IGSCC. The Dresden results (Cycle 9) show that even when hydrogen addition is stopped, IGSCC continues to be mitigated for about 10 hours.

The experience at Dresden 2 demonstrates that HWC can be implemented with a relatively minor impact on plant operation and with a major beneficial effect (mitigation of the IGSCC of the sensitized stainless steel). The corrosion product measurements showed th· 'IWC did not have a large effect on the transport oı soluble or insoluble elemental species.[54]

The principal side effect of HWC is an increased level of hydrogen and nitrogen in the steam. The increase in ^{16}N activity is a result of the change in primary coolant chemistry that occurs with the addition of hydrogen. The ^{16}N isotope is produced by an (n,p) reaction with the ^{16}O in the primary coolant. With standard BWR water chemistry conditions, most of the ^{16}N is probably in the form of nitrate, which remains in the water. Under the more reducing conditions produced by HWC, a larger fraction of the nitrogen will be in the form of volatile species (ammonia, nitrogen oxides), which will concentrate more in the steam phase.

The increased ^{16}N in the steam at Dresden 2 resulted in a five-fold increase in the radiation levels measured at the main steam line when the HWC was in operation. The relative increase in the radioactivity level of the main steam line at Ringhals was somewhat smaller, about a factor of 3. Increases in main steam line radiation were also monitored during the short-term tests at Peach Bottom 3, Pilgrim, and Fitzpatrick.

The HWC verification program at Dresden 2 included an extensive investigation of the performance of the fuel cladding and other Zircaloy core components using precharacterized fuel assemblies. Areas of emphasis included Zircaloy corrosion and hydriding as well as crud buildup on the fuel.[55] The results of the corrosion and hydriding studies indicate little or no effect of one cycle (Cycle 9) of exposure to HWC. Some measurable effects of HWC are seen from the analysis of crud, but overall the crud characteristics are still in the range considered normal for BWRs. There are no indications of any adverse impact on fuel performance.[56]

12.5 Repair of Cracked Piping

Four methods are considered to be acceptable for the repair of BWR piping systems when cracks are found in the heat-affected zones.[28] The methods include

1. Weld overlay reinforcement
2. Stress improvement (for minor cracks)
3. Mechanical clamping devices
4. Partial replacement.

Weld overlay reinforcement was initially used as a short-term repair method, but the method currently appears suitable for at least a limited longer use. Stress improvement is an effective repair method only for minor cracks, and detailed crack sizing must be carried out after stress improvement. Mechanical clamping devices provide temporary reinforcement for cracked welds. This repair method has been used on a demonstration basis only. Partial replacement provides a fully effective repair if IGSCC-resistant material is used along with qualified processes.

Weld Overlay Reinforcement. Weld overlay reinforcement is the technique most widely used for field repairs of BWR piping containing IGSCC. The procedure consists of applying a layer of weld metal over the original weld and heat-affected zones. The overlays are made by applying weld metal completely around the outside surface of the pipe and overlapping each pass. Figure 12.11 shows a typical weld overlay. The weld overlays are fabricated using low-carbon high-ferrite 308L weld metal for the repair, and the welding is performed with cooling water flowing through the pipe during application of the overlay. This cooling during application prevents further sensitization of the inside surface of the piping under repair. It also produces a residual compressive stress field at the inside surface of the piping under the overlay.

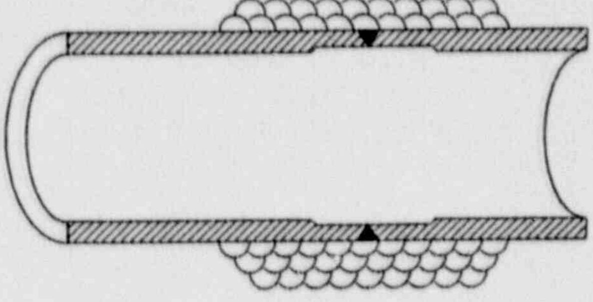

Figure 12.11. Schematic of typical weld overlay reinforcement.[45]

The standard overlay is designed to provide a new pressure boundary even if the original piping contains a through–wall crack a full 360 degrees around the pipe. In cases of axial cracks (perpendicular to the welds) and very short circumferential cracks, a design overlay can be used that takes credit for part of the original piping. The compressive stresses induced by the weld overlay inhibit crack initiation and further growth. Analytic results indicate that the stresses ahead of any cracks that do not extend further than 60% into the wall will be compressive, inhibiting further growth. In addition, the weld material used in making the overlay is itself more resistant to IGSCC than sensitized Type 304 stainless steel and provides a barrier that tends to limit further crack growth.

Weld overlays were developed as a short–term solution to allow plants to continue operating until permanent corrective measures were taken. The overlays were initially approved for only two cycles of operation. The major barrier to extended use was the difficulty in performing proper inservice inspections of the overlays to demonstrate continued integrity. The NRC requires positive assurance that cracks have not progressed into the overlay before operation for additional cycles. In addition, the NRC has stated that the inspection procedure should be capable of detecting cracks that were initially deeper than 75% of the original wall thickness and capable of detecting additional cracks that have grown deeper than 75% of the original wall thickness.

Ultrasonic techniques are usually used in inspecting for IGSCC. However, there are several problems associated with the inspection of weld–overlay–repaired piping using conventional ultrasonic techniques. The first is that the surface of the overlay is not smooth, causing a dispersion of the incident beam. Second, this problem is aggravated by the anisotropy of the weld material, which further attenuates the signal. Third, the interface between the overlay and the original piping is a reflecting surface for the ultrasonic beam, which also increases the difficulty of inspection. Finally, the application of the overlay produces a compressive stress on the inner region of the piping and tends to close up the existing cracks, reducing the signal reflected from the crack.

Improved ultrasonic inspection methods have recently been developed at the EPRI/NDE Center, which allow piping under weld overlays to be inspected for IGSCC. The improved inspection methods appear to meet the NRC criteria discussed above. A surface condition specification has been developed to eliminate the dispersion of the initial beam, and longitudinal ultrasonic waves are used to minimize beam attenuation in the overlay.[57] Deep cracks in the original piping and fabrication flaws (lack of bonding) in the overlays can be detected. To date, shallow cracks near the inside surface cannot be detected, but this is not required for qualification of the overlays for additional use. Weld overlay reinforcements have been inspected with these methods, after their initial two cycles of approved use, and are now in their third cycle of operation.

The inspection schedule for cracked piping repaired by weld overlay reinforcement requires all of the overlays to be inspected during every two refueling cycles.[28] Half of the overlays should be inspected during the first refueling outage after repair.

Although weld overlay reinforcements were developed as a short–term measure, extended use is possible with adequate inspection. The useful lifetime of weld overlay reinforcements appears to be limited by the stabilization of the cracking in the original piping. If the cracking under the overlay continues to grow, it will eventually reach the overlay. Although the overlay material is known to be resistant to IGSCC, cracks have penetrated from sensitized Type 304 stainless steel into Type 308L weld material.[57,58] Another potential limitation to the extended usage of weld overlays could be fatigue. However, the growth of existing cracks due to both fatigue and stress corrosion was considered in the design analysis of the weld overlay repairs for Hatch 1.[59] The analysis showed that the design life was in excess of 5 years, and that growth of fatigue cracks and the fatigue life were not limiting factors.

Stress Improvement. Several of the stress–improvement methods developed for IGSCC mitigation can be used to repair BWR piping containing shallow cracks. The method most widely used to date has been the induction–heating stress–improvement method. The stress–improvement methods result in a residual stress pattern with a tensile stress in the outer part of the pipe wall and can only be used for shallow cracking. If the cracks extend deeper than halfway through the wall or if there are applied stresses that result in a tensile stress field at the crack tip, crack propagation will not be inhibited by the repair process and, in fact, may be encouraged by the treatment. Detailed crack sizing is required after the application of stress improvement, and then reinspection of the weld is required every two refueling cycles.[28] This treatment is not recommended for axial cracks, for short cracks deeper than 30% of the wall thickness, for circumferential cracks greater than 10% of the circumference, or when the service stress on the weldment exceeds the code design stress intensity S_m.

While stress improvement and weld overlays appear to provide acceptable methods for stabilizing existing IGSCC, these two methods do have a serious drawback in that higher inservice inspection frequency and larger inspection–sample size are required. This is costly in terms of both resources and radiation exposure. For long–term operation and for extended life, further work is needed to provide confidence in the various long–term repairs.

Mechanical Clamping Devices. Mechanical clamping devices are designed to retard IGSCC crack growth and to prevent pipe breaks. Tightening of studs on the clamping devices produces axial and circumferential compressive stresses in the pipe wall that may potentially mitigate crack growth during operation. In addition, clamping devices provide alternate load paths around degraded weldments and ensure their structural integrity. One such clamping device, called Pipelock, is available from O'Donnell & Associates.[60] Preloaded bolts with axis parallel to the pipe center line, bring the two halves of the pipelock, which are mounted on the two sides of the cracked weld, together and produce compressive stresses in the pipe and the weld. Pipelocks can be readily removed for inspection of the welds.

Partial Replacement. Partial replacement consists of simply cutting out the section of piping that contains welds affected by IGSCC and replacing it with a new section. This method will produce a permanent repair when IGSCC–resistant material is used and the installation welds are IGSCC–resistant. High–ferrite 308L weld metal and heat–sink welding or a stress–improvement process should be employed. This type of repair requires that the section of piping to be replaced is drained and dried which may require defueling of the reactor. Also, this repair usually results in high–radiation exposures to repair personnel, especially at older plants. Finally, when a replacement section of piping is welded into place, some shrinkage (about 200 to 300 mils) will occur across the welded joints in the axial direction. This will alter the applied stresses in the system being repaired and has the potential for producing tensile stresses in older, less IGSCC–resistant pipe joints. The same concern applies to the replacement of single components such as elbows and valve and pump bodies.

12.6 Summary, Conclusions, and Recommendations

The BWR recirculation piping has experienced considerable degradation caused by IGSCC, including through–wall cracking, in the recirculation piping. The IGSCC failures of the recirculation piping have been addressed by a number of industry– and NRC–sponsored programs, and a variety of countermeasures have been developed, which are listed in Table 12.6. Countermeasures for mitigating the other degradation mechanisms active in BWR recirculation piping are also listed in Table 12.6. Countermeasures for repair and replacement of degraded recirculation piping are also listed. However, long–term field–experience data are needed to assess the effectiveness of the various countermeasures. The conclusions and recommendations regarding the BWR recirculation pipe cracking are as follows:

1. Three stress improvement methods, heat sink welding, induction heating stress improvement, and mechanical stress improvement effectively mitigate IGSCC by introducing residual compressive stresses in the heat–affected zone on the inside surface of the recirculation piping.

2. The stress improvement methods introduce compressive stresses at the tip of shallow cracks in the heat–affected zone and are effective in inhibiting the growth of short cracks not exceeding 30% of the wall thickness. However, a higher inspection frequency and larger sample size are required for these welds.

3. Use of hydrogen water chemistry has been successful in suppressing IGSCC crack initiation, provided it is combined with very low levels of ionic impurities. Hydrogen water chemistry is effective when the level of dissolved oxygen is reduced below 20 ppb and the coolant conductivity is kept below 0.2 μS/cm. On–line monitoring of coolant chemistry and periodic IGSCC tests are recommended.

4. Short–term laboratory tests under simulated conditions show that the use of hydrogen water chemistry significantly increases the initial general corrosion rate of the carbon steel components. However, once a corrosion film is formed, the general corrosion rate

Table 12.6. Summary of countermeasures for recirculation pipe cracking

Mechanism	Countermeasure	Mitigation	Repair	Replacement
IGSCC	Inductive heating stress improvement	X	X	X
	Heat sink welding		X	X
	Mechanical stress improvement	X	X	X
	Solution heat treatment			X
	Corrosion resistant cladding			X
	Nuclear grade material			X
	Hydrogen water chemistry	X		
	Weld overlay		X	
	Clamping device	X	X	
TGSCC	Hydrogen water chemistry	X		
	Minimize cold working in fabrication			X
Thermal embrittlement	Use of less susceptible material			X

appears to be similar to the normal water chemistry corrosion rate. Long-term evaluation of the erosion-corrosion of carbon steel components subjected to hydrogen water chemistry is recommended.

5. Weld overlay introduces compressive stresses in the weldment and inhibits IGSCC crack initiation and growth. Analytical results indicate that weld overlays will inhibit the growth of cracks that do not extend beyond 60% of the wall thickness. The major barrier to extended use of weld overlays is the difficulty in performing reliable inspections of the weldment under the overlays. Improved ultrasonic methods have been developed for this purpose. All welds repaired by weld overlays should be inspected within each two refueling cycles.

6. Mechanical clamping devices introduce axial and circumferential compressive stresses in the piping and retard crack growth. In addition, such clamping devices provide an alternate load path around the degraded weldment and ensure its structural integrity.

7. Solution heat treatment of piping shop welds eliminates sensitization in the heat-affected zones and, thus, provides protection against IGSCC. This treatment is applicable to new piping, and, at present, approximately 40% of

the welds in the recirculation piping are solution heat treated.

8. Types 304NG and 316NG stainless steels are much more resistant to IGSCC and have been qualified as alternate materials for BWR piping. However, Type 316NG does not have the same weldability as Type 304 stainless steel, and it is susceptible to transgranular stress corrosion cracking (TGSCC). Laboratory results show that the use of hydrogen water chemistry and strict control of impurities in the coolant can mitigate TGSCC. Use of Type 347NG is currently being evaluated.

9. Application of corrosion–resistant cladding on the inside surface of the piping protects any sensitized surfaces from exposure to the BWR coolant, and has been successfully demonstrated. Corrosion resistant cladding may be applied to the new piping weldments in the shop or field.

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13. PRESSURIZED WATER REACTOR AND BOILING WATER REACTOR CABLES AND CONNECTIONS IN CONTAINMENT

J. B. Gardner and L. C. Meyer

This chapter presents an aging assessment of the cable systems used within the containments of United States nuclear power plants. Cable systems, which consist of cables and connections, provide the path for signals between sensors and the electronics used for the protection and control of the reactor, and for the control and powering of equipment used during normal operation and in mitigating the effects of accidents. Thus, cable systems are important to plant safety both during normal operation and under accident conditions. This chapter contains (a) a discussion of the various types of 1E cables and connections and their materials of construction; (b) identification of the stressors, aging degradation sites, mechanisms, and potential failure modes, and aging-effects indicators; (c) an evaluation of the importance of operating experience records to component life assessments; (d) an evaluation of methods currently in use and others proposed for detecting aging effects and degradation; (e) a general discussion of possible approaches to cable system life assessment related to various qualification situations that may prevail at plants; and (f) conclusions and recommendations.

Cables and connections used in fossil fuel and hydroelectric power plants have generally performed well for 30 to 60 years or longer. Many such older cables are still in use even though the thermal and environmental resistance of their insulation and jacket materials are inferior to the newer cables and connectors. There is good reason to expect that many of the low-voltage cable systems in nuclear plants will operate well, far longer than 50 years, because industry specifications and cable performance have improved significantly in recent years. However, exceptions may result because of errors or oversights in cable design, manufacture, or installation, or because of environments that are more severe than expected. Also, cables in reactor containments are exposed to the additional environmental stress of radiation, which is a new element of uncertainty in predicting long-term behavior. The potential for common-cause failures[a] is another concern.[1]

The nuclear qualification program requires licensees to demonstrate that the components of cable systems are capable of operating during and/or after the sudden imposition of a harsh environment, which might accompany a postulated design-basis event (DBE). Demonstrations normally involve a preaging process to put the components in that aged condition expected at the end of their initial design life (generally 40 years for cable). Thus, the qualification program "looks into the future" only as far as the preaging of samples before conducting loss-of-coolant accident (LOCA) or seismic tests.

Unlike most of the other equipment discussed in this report, the operating performance of cable systems and present industry testing of those systems during normal service provide only a limited perspective on the capability of cable components to continue operating in a high-stress environment resulting from seismic or pressure boundary leak accidents. Condition monitoring of cable system components with the methods available today, either done in situ or on removed samples, will also provide limited insight into the potential performance of cable systems exposed to harsh DBE conditions. Data on the condition of preaged components before qualification tests need to

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a. Common-cause failures (CCF) involve more than one failure resulting from a single event and its consequences. Those CCFs with great impact to safety occur over a time interval too short to allow repair or replacement to mitigate the initial failures. An example would be post-LOCA failures, where a number of failures at various locations within the containment might first result from polymer deformation during the initial temperature-pressure cycle, and somewhat later, chemical spray seeping into various connections. The modes of failure differ, but all have a single cause and, in this case, access to repair of the first type of failure is not possible before the second type occurs.

be compared with inservice conditions to ensure DBE performance. Therefore, this chapter addresses concepts of cable and connections qualification and environmental aging and does not focus on analysis of normal operating experience or standard test procedures (as is the case with pressure boundary components).

Issues in the assessment of the remaining useful life of cable systems in containment stem either from an interest in extending the original qualified life, or from concerns about the completeness or technical validity of the qualification programs.

13.1 Description

The cable systems within the scope of this study are those interconnecting separate units of electrical equipment within nuclear reactor containments. This study does not include the internal wiring within manufactured units of equipment. The cables are distributed over many areas of the containment with varying environmental conditions and encounter many interfaces where interactions may cause cumulative aging effects, which, if not mitigated, lead to degradation. The varieties of cables noted in the following section, as well as stressors described in Section 13.2, give rise to a complex matrix of possible situations. Therefore, the approach to analyses of individual station aging should be to focus on high–priority areas of concern, using the general guidance available from this and other studies.[2]

13.1.1 Cables. The safety system cables in the containment of nuclear power plants are used in the following classes of applications:

- Power – at a rating of 600 V and below, dominantly ac.

- Control – voltage ratings used primarily to differentiate between various insulation wall thicknesses available from suppliers rather than to limit the operating voltage, which may vary from microvolts to 440 V, either ac or dc.

- Instrumentation – normally very low–energy circuits of either high or low impedance using dc, ac, or pulse signals.

There is no generally accepted distinction between power and control cables. Sometimes cables are distinguished by their operational function and sometimes by their load current levels, or simply by their conductor size. Also, designs of and materials used for power and control cables overlap, so the distinction may not be important for this and other studies. Figure 13.1 illustrates several cable designs.

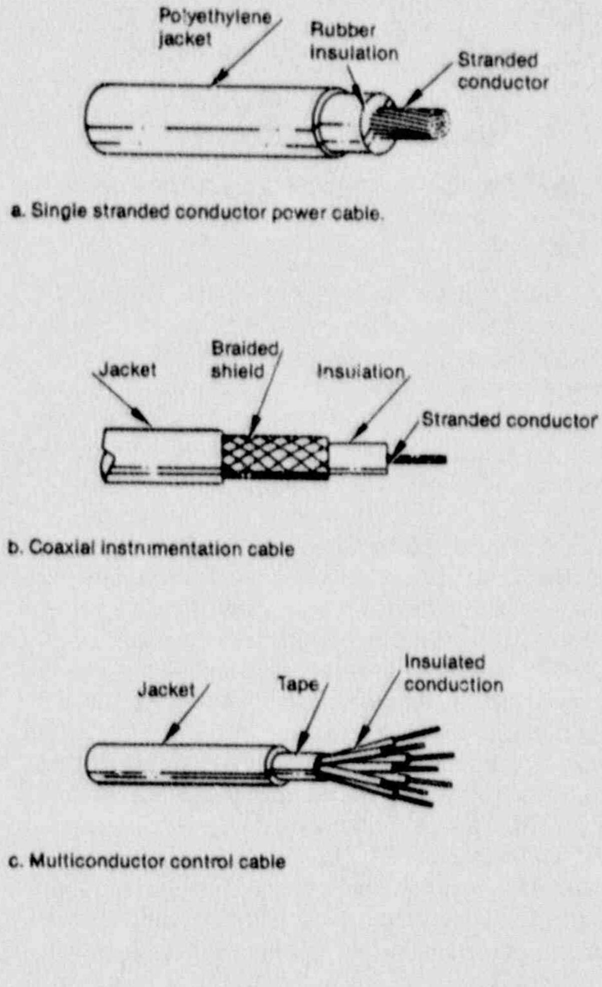


Figure 13.1. Examples of cable construction for cables used in nuclear power plants.

Instrumentation cable includes thermocouple (single or multiple pairs), twisted shielded pair (single or multiple), coaxial, twinaxial, triaxial, and multiconductor with conductors arranged in concentric layers.

Mineral–insulated (MI) cables consist of metallic tubes with conductors embedded coaxially within compacted mineral powder insulation. They are used for instrumentation or control functions in very high thermal or radiation stress areas.

Cables in containment may be installed in open or covered trays, or in rigid metal conduits. Cables leading to and from equipment cases are often in flexible conduits to allow for movement and vibration.

A large amount of cable is used in a nuclear containment. A new boiling water reactor (BWR) requires the following approximate total lengths of cable[3]:

- Power 57 miles
- Control 46 miles
- Instrumentation 253 miles

A large fraction of those cables are safety related, so the life assessment of cable systems is an important issue.

The primary function of any cable system is to convey electrical signals or power from point to point. A cable system must function in normal service for many years and also remain functional under the extraordinary stressors resulting from any design-basis event (DBE). Such systems require careful selection of materials and designs of components.

Conductors and Shields. The conductor material for most cables is stranded copper, often with tin or some other coating to prevent copper/insulation interaction and to provide good corrosion-resistant connections. Materials used for cable conductors and metallic shields, and in connector components are listed in Table 13.1. Different constructions and dimensions may affect the resistance of conductors and shields to environmental and service aging effects. For example, corrosion, which is a chemical reaction starting on exposed surfaces, will more readily degrade a very thin metal layer or more finely stranded conductor (higher surface to volume ratio). On the other hand, constructions that are more sensitive to corrosion will generally be more flexible and more resistant to rupture caused by vibration or flexing during service.

Shields on low-voltage cables are used to isolate circuits from one another and outside interference and to provide a constant electrical impedance along the circuit to ensure proper transmission of high-frequency or pulse signals. The presence of a shield or tape barrier between a cable's inner conductor(s) and jacket can prevent a crack in the jacket from propagating into and through the conductor insulation.

Insulations. The insulations of cables and connectors are generally polymer-based compounds (except for MI cable). Depending upon circuit requirements, insulations serve to isolate the electrical conductors from ground, and sometimes to maintain high dc resistivity, low ac losses, or proper concentricity of conductor and shield. The dielectric properties of breakdown strength and insulation resistance are particularly important. Common-cause failure modes are often related to the insulation resistance of low-voltage cables (or its inverse, dc leakage current). The halogenated polymers, neoprene and hypalon, have the lowest insulation resistances. The compounding additives used to manufacture these polymers may have a major adverse effect on the insulation resistance and on the rate of aging change of the insulation resistance in wet and high thermal or radiation environments. Therefore, any highly filled compound is potentially susceptible to the problems of low insulation resistance when subjected to the steam/heat/radiation stressors of a severe accident after an extended period of aging. In addition, insulations must have mechanical properties that allow flexibility, resistance to installation abuse, and resistance to environmental stress.

The mechanical properties of generic polymers can also be substantially affected by the compounding ingredients that are added during fabrication and by the manufacturer's processing methods. However, there are broad, generally valid differences between polymers. Silicone rubber is very flexible but is the least resistant to tear and to crushing. Ethylene propylene rubbers (EPRs), although quite flexible, are more resistant to mechanical abuse. Neoprene and hypalon are sometimes used as insulation and are much stronger materials while still rubbery. Polyethylenes and cross-linked polyethylenes are much stiffer and more abuse resistant at normal operating temperatures. Polyethylenes and polyvinylchlorides (PVCs) can become quite fluid, and cross-linked polyethylene (XLPE) much softer than EPRs at transition temperatures of 100 to 120°C (212 to 248°F). PVC properties at normal operating temperatures depend entirely upon the plasticizers used in the PVCs, and the initial properties may vary greatly; and the change in those properties after aging may also vary greatly. Butyl rubber was used as an insulation material in the older plants. But field experience has shown that some butyl rubbers are very sensitive to radiation and some are sensitive to moisture. Therefore, use of butyl rubber has been discontinued and cables with this insulation material have been replaced in several older plants. Kapton is a very strong high-temperature polymer supplied as a film laminate to cable manufacturers. It is spirally wrapped over a conductor and subjected to heat treatment that fuses together the surface laminate material to produce a seal against electrical breakdown and environmental intrusion. Other polymers less widely used in nuclear plants are compounded by the material suppliers and their properties are less subject to variation resulting from cable manufacturing differences. Table 13.2 lists most of the insulation and

Table 13.1. Materials for metallic components in cable systems[a]

Material	Use	Aging Concern	Level	Degradation Mechanism
Stranded copper (bare or tinned)	Cable conductors	Yes	Medium	Corrosion
Solid copper (bare or tinned)	Cable conductors	Yes	Low	Corrosion
Nickel–plated copper	Cable and connector conductors, terminals	Yes	Medium	Corrosion, wear
Silver–plated copper	Connector pins	Yes	Medium	Corrosion, wear
Nickel–rhodium–plated copper	Connector pins	Yes	Medium	Corrosion, wear
Gold–plated copper	Connector pins	Yes	Low	Wear, gold–solder interaction
Copper connector (bare or tinned)	Splices and terminals	Yes	Low	Corrosion, splice loosening with age
Braided copper (bare or tinned)	Shield	Yes	Medium	Corrosion
Tinned copper tape	Shield	Yes	Low	Corrosion
Aluminum foil	Shield	Yes	Medium	Corrosion
Metallized Mylar tape	Shield	Yes	High	Corrosion
Stainless steel	Cable sheath, (mineral insulated cable), conductor, connector parts	No	—	—
Inconel	Cable jacket, conductor	No	—	—
Zirconium	Cable conductors	No	—	—
Chromel	Cable conductors, connector pins	No	—	—
Alumel	Cable conductors, connector pins	No	—	—

a. The indicated aging concerns are based upon observations reported in LERs and NPRDs and upon field observations. The relative levels of concern are subjective judgments based on general cable industry experience and considerations of exposed surface area–to–volume ratios.

Table 13.2. List of common cable and connector insulation and jacket materials, showing thermal and radiation degradation concerns[a]

Material	Potential for Significant Thermal Aging		Radiation Susceptible		Where Materials Are Used			
	10 Yr	40 Yr	Rads Gamma	Basis[b]	Cable	Connector	Penetration	Splice
Polyester (unfilled)	*	*	10E5	Threshold	X	—	X	X
Nylon (polyamide)	*	*	10E5	Threshold	X	X	X	—
Polyethylene	*	*	10E7	Absorbed	X	X	—	X
Neoprene (chloroprene) (jkt)[c]	*	*	10E7	Absorbed	X	X	X	—
Ethylene propylene rubber (EPR)	*	*	10E7	Absorbed	X	—	X	X
Hypalon (Chlorosulfonated polyethylene) (jkt)	—	*	10E7	Absorbed	X	—	X	—
SBR rubber	—	*	10E6	Threshold	X	—	—	—
Cross-linked polyethylene (XLPE)(jkt)	—	*	10E7	Absorbed	X	—	X	X
PVC (polyvinylchloride) (jkt)	Not available[d]							
Butyl rubber	—	—	10E6	Absorbed	X	—	—	X
Kapton (polyimide)	—	*	10E6	Threshold	X	—	X	—
Silicone rubber	*	*	10E6	Threshold	X	X	X	X
TEFZEL	—	*	10E6	Absorbed	X	—	—	—
Phenolic P-4050	—	—	10E6	Threshold	—	X	—	—
RTV silicone	—	—	10E7	Absorbed	—	X	—	—
Polyester glass laminate, Grades GPO-2, GPO-3	—	—	10E7	Threshold	—	X	—	—
Polythermaleze	—	—	10E8	Threshold	X	—	—	—
Aluminum oxide (Al_2O_3)	—	—	—	—	X	—	—	—
Magnesium oxide MgO	—	—	—	—	X	—	—	—

NOTES:

* The asterisk indicates that there are data available that show a potential for significant thermal aging of the materials when exposed to normal operating conditions for either 10 or 40 years, as shown.

X The X indicates that the material is used for the application indicated.

a. This table is based primarily on material presented in USNRC IE Bulletin 79-01B, January 1980, Table C-1. Values given are not intended to be used as a basis for engineering analysis or decisions. They are presented to offer a broad perspective on the relative sensitivity to the stressors and extent of application of the materials.

b. The term *Threshold* refers to damage threshold, which is the radiation exposure required to change at least one physical property of the material. The term *Absorbed* refers to the radiation that can be absorbed before serious degradation occurs.

c. The symbol (jkt) indicates that a polymer is commonly used for a jacket compound as well as insulation.

d. PVC properties vary widely so that specific [illegible] meaningful.

jacket materials used for cables and connectors, and the effect of thermal and radiation stress on those materials. Section 13.4 contains further discussion on cable materials and their aging effects.

Jackets. The term *jacket* in the cable industry refers to extruded polymers, except for silicone cables where it is applied to a textile braid woven over the insulation for mechanical protection. Jackets are often considered vital in maintaining the hermetic integrity of a cable system, as well as furnishing outer protection. Jacketing materials protect individual wires as well as multiconductor cables. While there are certain minimal electrical requirements for jacketing compounds, selection of those compounds is usually based on mechanical, environmental resistant, or fire-resistive properties. The mechanical properties of the polymers used for jackets are compared in the above section on insulation. Mechanical endurance and fire-suppressing properties have been dominant considerations in the selection of materials for most nuclear cable jackets. Those properties can be enhanced by the use of halogenated polymers and/or the addition of large proportions of halogen compounds and mineral fillers, both of which may adversely affect long-term aging and moisture transmission properties.

13.1.2 Connections. Figure 13.1 contains examples of the cable construction used in nuclear power plants. In the context of this study, the phrase *cable connections* refers to terminals, splices, and those seals to the cable (usually close to a terminal or splice) that are required to ensure proper function of the cable system and connected equipment.

Connectors. Cable connectors are devices at cable ends that enable continuity of conductor, insulation, and environmental seals. Conductor (or wire) connectors are devices that provide conductor continuity only. Cable connectors in nuclear containments are often prefabricated mated (pin and sleeve) devices. Multiconductor connectors normally have outer gasket-type seals, and inner seals around individual conductors made of filler compounds or sealing cements. See Figure 13.2 for an example of a multiconductor connector design.

Splices. Permanent cable splices are used in containments to reduce the number of connection points that must be maintained. Splice designs using crimped wire connectors and overall waterproof shrink tubing allow for simplified installation procedures and detection of errors in assembly. See Figure 13.3 for examples of permanent splices using heat-shrink tubing with internal sealants.

Terminal Strips. Terminal strips have been used in the containment junction boxes of older plants. Such use has resulted in many problems, and splices have generally now replaced the terminal strips in the older plants and are included in new designs.

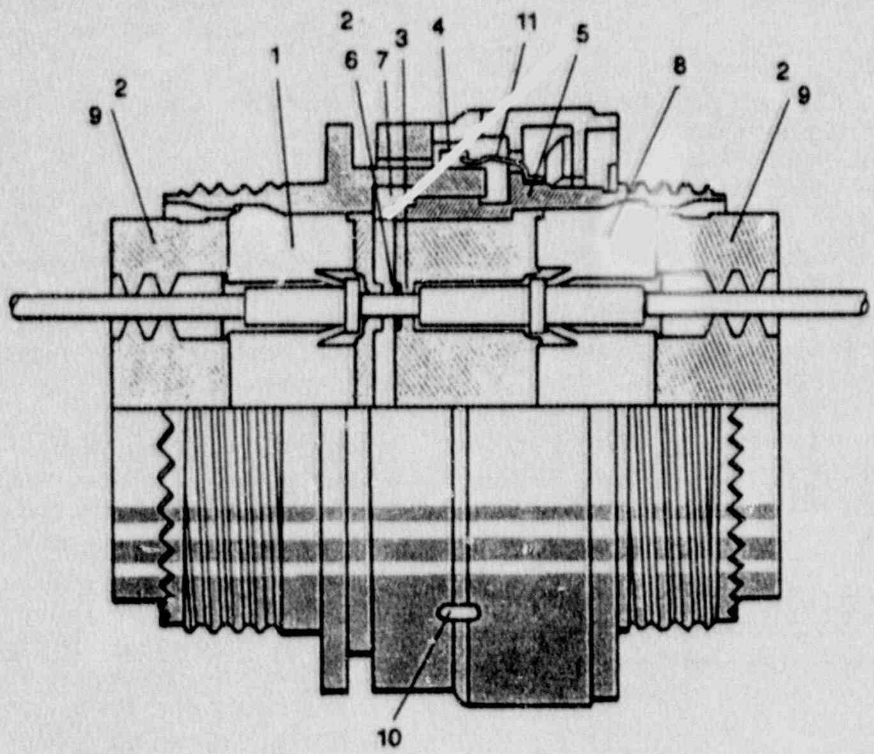
Penetrations. Penetrations through containment walls, as covered in IEEE Standard 317-1983, are beyond the scope of this study. Penetrations of cables into the enclosures of equipment such as motor terminal boxes, motor-operated valve cases, or terminal-strip junction boxes are included in this study. The integrity of the environmental seal of such penetrations must be maintained without injury to the cable. The performance of the penetrations is closely related to the cable materials and design. Different combinations of mechanical gaskets, stuffing boxes, compound fillers, cements, and sleeves are used with various potential mechanical or chemical interactions with the cables. Those interactions are considered aging effects because they usually occur over long periods of time.

13.1.3 Other Interfaces. Cables can be affected by or have effects on other components with which they come in contact. Therefore, some consideration of such interfaces is necessary in any assessment of potential aging effects and determination of service life for cable systems. Interfaces of possible concern include conduit sealing compounds, fireproofing, fire stops at wall or floor pass-throughs, large accumulations of pulling compounds, oil or hydraulic fluid spills, and cable binders or ties.

13.2 Stressors

Normal and DBE-related stressors are the two types that affect the life of cables. With few exceptions, DBE-related stressors are more severe. Within any practical lifetime, normal stressors may have no effect on serviceability, may lead to failures during normal service, or may cause aging degradation so that DBE-related stressors can eventually cause failures. DBE-related stressors may also cause immediate failures in age-degraded systems because of the high intensity or unusual nature of the stressor. Nuclear qualification programs aim to prevent failures resulting from DBE-related stressors because of their safety implications. Normal and DBE-related stressors of possible importance to cable and connection aging are listed in Table 13.3.

The relationships between aging stressors and modes of failure must be considered to properly



Connector features

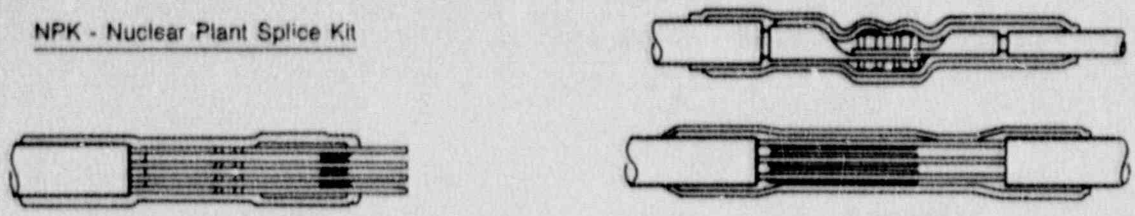
1-Molded one-piece contact retention disc.
2-Fluorosilicone fluid resistant seal material.
3-Closed entry socket insert and contacts.
4-Bayonet coupling system.
5-5 key shell polarization.
6-Interfacial mating seal.
7-Static peripheral shell seal.
8-Monoblock construction-inserts bonded to shells.
9-Self-sealing rear grommets.
10-Visual mating indicators.
11-Shell-to-shell grounding fingers.
12-Accepts Mil-C-38999 hardware.
13-Conductive shell finish.

Construction Materials

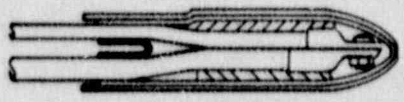
Item	Material	Aging concern	level	Problem
Pin contact	gold plated copper	yes	low	wear with use
Socket contact	gold plated copper	yes	low	wear with use
	stainless steel hood	no		
Shells	Aluminum	no		
Coupling ring	Aluminum	no		
Retention disc and inserts	Thermoplastic Polymer	yes	low	wear with use
Grommets and seals	Fluorosilicone Elastomers	yes	high	cracking
Bayonet Rivets	Stainless steel	no		
Finish (shells and coupling ring)	Cadmium plate over nickel	no		

Figure 13. 2. Amphenol 418 series multiconductor connector.

NPK - Nuclear Plant Splice Kit



NPKV - Nuclear Plant Stub Connection Kit ("V")



Construction Materials

Item	Material	Aging concern	Level	Problem
Tubing and sealant	WCSF-N	Yes	Low	Cracking and leakage
Crimp	Copper	Yes	Low	Corrosion

8-73?6

Figure 13. 3. Raychem NPK and NPKV splice assemblies.

address safety concerns related to life assessment and potential common cause failures.

13.2.1 Normal Stressors. Table 13.3 distinguishes between normal environmental and normal operational stressors. Environmental stressors depend on the location of a component, whereas operational stressors result from usage or maintenance.

Aging Effects of Thermal/Radiation/Oxygen Stressors.[a] Thermal and radiation stressors in the presence of oxygen cause complex chemical changes in all polymeric materials. Many aging-related cable qualification programs, including those recommended in IEEE 383-1974 and IEEE 572-1985, have considered the aging effects of thermal and radiation stressors as independent and additive. Recent research efforts have demonstrated that for some polymers, synergistic effects make accurate prediction of long-term aging effects rather complex or even impossible at the present state of the art.[2]

In general, the mechanical effects of thermal and radiation stressors are quite similar, but the electrical effects (momentary and cumulative) may be rather different. Engineers have used rule-of-thumb thresholds for temperature and radiation levels. Below those levels, the aging effects on high-quality polymers are so small that the practical lifetime of polymeric materials need not be a design factor. For temperature, the threshold level is commonly assumed to be 35 to 40°C (95 to 104°F) for most cable insulations and jackets. For radiation, the levels shown in Table 13.2 indicate rough estimates of thresholds for those polymers. Generally, 10^4 rads gamma is accepted as a radiation level below which aging effects are not a concern.[4]

The effects of thermal and radiation exposure are drastically reduced in the absence of all oxygen (see Section 13.4.1 for further discussion). However, oxygen is present in power plant reactor containments at a sufficient partial pressure to diffuse into organics over long periods and feed the chemical reactions triggered by the thermal and radiation stressors. Even so-called inerted atmospheres, reduced to 4% oxygen by volume to limit hydrogen burning during a severe accident, may not limit long-term polymer aging effects.[2]

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a. The term *aging effects* denotes any changes in physical, electrical, or chemical properties with passage of time. *Degradation* denotes such changes of a nature and magnitude as to impair performance.

Table 13.3 Aging stressors for safety system cables and connectors

Normal

Environmental	Usual Importance[a]
Thermal	High
Radiation dose	High
Oxygen availability	High
Moisture, high humidity	High
Distortion pressure	Medium
Surface dust	Medium
Chemicals	Medium
Operational	
Thermal cycling	Medium
Maintenance movement/flexing	Medium
Maintenance disconnecting	Medium
Momentary overload currents	Low
Current/voltage surges	Low
Temporary moisture/chemicals	Low

DBE–Related

Steam condensation	High
Temperature–levels and gradients	High
Pressure- levels and gradients	High
Radiation–rate and total dose	High
Water/chemical spray	Medium
Submersion	Medium
Flexing	Low
Fire[b]	Low

a. The importance rankings are subjective judgments as those *generally* applicable, but in any particular situation, the ordering may not be appropriate.

b. An initiating fire is not a DBE, but test for resistance to fire propagation is included as a Class 1E cable qualification requirement in IEEE 383–74.

Recent studies[a] have indicated that there may be a marked drop in the aging rate with a reduction in atmospheric oxygen if the cable construction substantially limits the diffusion of oxygen into the internal portions of the cable. An example of such a cable construction is the use of a relatively heavy outer extruded jacket of multiconductor cables. Even in normal atmospheres, heavy extruded jackets and sealed helical armor or helical metal tape apparently provide better protection of the underlying insulation by limiting the oxygen diffusion into the insulation. However, the authors are not aware of any quantitative evaluations of the benefits of such constructions.

a. K. T. Gillen, private communication, Sandia National Laboratories, April 1989.

Moisture. The design specifications for relative humidity in reactor containments can be as high as

100%.[a] Leaks are the most common cause of high values over long periods. The exposed water surfaces make the containment humidity in BWRs usually higher than in PWRs. When the humidity rises to levels that induce condensation, water may accumulate in conduits and remain there for many years. Long-term cable immersion in water may result in moisture diffusion through jackets, which could initiate corrosion of shields or conductor strands and lower the insulation resistance of filled insulations or moisture migration along the cable into the connections of adjacent equipment.

Distortion Pressures. The extruded polymers used in cables are pliable in order to reduce cable stiffness. However, those polymers do not have perfect elasticity when under moderate strain and they will permanently distort (or flow) when subjected to distorting pressure over long periods. High temperatures soften polymers and increase the amount of permanent distortion. Therefore, the coincidence of high temperature and high-distortion pressures produces the greatest potential for aging damage. Common incidences of high-distortion pressures involve cables that are pressed against sharp corners, supported by tight narrow clamps, or pulled nonaxially from connector housings.

Surface Dust. Exposed dielectric surfaces, which separate energized circuits from one another or from ground, will lose insulating value when contaminated by dust. The loss may be slight and even undetectable when those surfaces are kept very dry. When the dirty surface is subjected to high humidity or condensation, leakage current over the surface may result in erroneous signals, or total failure by short circuit or ground.[5]

Chemicals From Interfaces. Rubber- and plastic-based compounds frequently contain chemicals that will slowly diffuse to their surfaces. Those same chemicals may migrate from one polymer to another (when the two polymers are in direct contact) and produce adverse mechanical and electrical aging effects. Any substances that contain oily or moisture-soluble chemicals in their original composition or that produce such chemicals during aging can give rise to the diffusion of those chemicals into the polymers of cable system components contacting them. Examples of such substances are large accumulations of pulling lubricants, spilled oils or hydraulic fluids, fire-stop sealants, and conduit sealing compounds.

Thermal Cycling. Changes in temperature can be important because the resulting cable movements can shift cable positions adversely and because the large differences in coefficients of expansion between metals and organics can create mechanical stresses that disrupt seals. Also, thermal cycling can loosen electrical contacts. Cycling can result from changes in the current loading of power cables and from changes in ambient temperatures. Containment ambient temperatures have varied from 25°C (77°F) during refueling to 60°C (140°F) or higher during full reactor power.

Movement/Flexing During Maintenance. It is often necessary to move or to disconnect cables during the maintenance of connected equipment. The resulting movement and flexing of cables can cause degradation of seals, breakage of shield ground leads, or cracking of cable insulations or jackets if aging has already degraded them.[6]

Disconnecting For Maintenance. Some equipment may need to be disconnected periodically for test or removal. Repeated disconnecting may cause wear or deformation of the mating contacts, and degradation of the connector sealing systems.

Overload Currents. Operating contingencies may result in momentary or occasional overloading of some cables. Although such overloads are simply a source of short-term thermal cycling, they are considered separately because if an overload causes the highest peak temperature, it can amplify the effects of thermal cycling. Overloads can result in conductor temperatures of up to 130°C (266°F).[7]

Current/Voltage Surges. As aging stressors, surges are not considered a problem in low-voltage cable systems. However, surges can trigger failures of the insulation or the shields of cables that have been seriously degraded by other stressors.

13.2.2 DBE-Related Stressors. Common-cause failures are the greatest threat to safety that can occur in cable systems. The stressors associated with DBEs (Table 13.3) are the ones most likely to trigger multiple failures of cable system components that have suffered degradation through normal aging. In addition, delayed failures can result when circuits, which are required to operate for extended periods after DBEs, are subjected to the accelerated aging effects of exposure to postaccident environments. All containment cable system failures initiated by either DBE or post-DBE stressors must be considered the result of a common cause whether failures occur immediately or are delayed. That is due to the probable inaccessibility of the containment during the postaccident period.

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a. Dave Larson, private communication, Duke Power, April 1986.

LOCA, MSLB, and Seismic Events. Containment equipment qualification programs that use IEEE 323, IEEE 383, IEEE 572 and RG 1.89 for guidance address most of the DBE-related stressors listed in Table 13.3. Such programs are designed to demonstrate operability during and after a DBE. In cases wherein the specifications, the state of technology, or regulations did not cover some of those stressors or did so in a manner not acceptable today, special programs may be necessary for assessing the remaining useful (qualifiable) life of equipment.

Loss-of-coolant-accident (LOCA) and main-steam-line-break (MSLB) stressors vary according to reactor, containment, and cooling/condensation design provisions. Stressor/time profiles for plants are established in the design stage but are subject to revision from time to time as research programs develop more refined modeling of accident scenarios.

Seismic events, pipe whipping, water hammer, and other accident-related phenomena can cause cables to be flexed. The extent of such flexing is difficult to define because of the great variety of installation configurations and the fact that cable movement during an accident will be determined by the movement of the equipment, cable trays, or structures the cable is attached to. Many of the configurations, although within certain design limits for bending or unsupported gaps, are dictated by field construction conditions. The derivation of the exact relative displacement history between numerous structures or components spanned by cables and subject to somewhat different accident loadings (movement) is totally impractical. For example, in most containments there are many cable transitions from cable trays to rigid conduit secured to equipment or structures other than the trays. In those cases, the positions of cables in the trays and of the conduit entrances relative to the tray are both determined by field construction, and the trays and conduit entrances are subject to different accident loadings and movements. With such indefinite configurations and accident loadings, the capacity of cables to withstand mechanical stressors has been addressed indirectly through demonstration of the flexibility of the cable either after the qualification preaging program or after that and the LOCA/MSLB tests. The capacity of cables to bend without rupture, as indicated by the associated wet high-voltage tests in IEEE 383-1974, Section 2.4.4, provides strong evidence that cables can resist damage when subjected to the somewhat indefinable movements associated with DBEs.

IEEE 572-1985 "Qualification of Class 1E Connection Assemblies for Nuclear Power Generating Stations" does specify seismic testing of connections. However, the use of this standard has been limited, especially in the older plants.

Submersion and Fire. The potential for large water leaks or discharges into containment introduces submersion of cable systems as a concern for common-cause failures. Demonstration of the acceptability of cables and splices in underground or other wet environments as addressed in commercial specifications (see IEEE 383-1974, Section 2.3.1) and demonstration of the ability of cables to withstand the prolonged LOCA steam/spray conditions used in environmental qualification type-testing, have been accepted as adequate evidence of cable and connection resistance to wet conditions. Therefore, the effects of normal aging on the operability of cables during submersion has not been a concern. There is less of a basis for confidence in the ability of connections to function under submergence after extended aging if they depend upon O-rings or compression seals against cable polymers, or are not sealed against water ingress from cable internals.

Fire has not been defined as a DBE by regulatory guides but it is an evident threat to safety. Cables are a major contributor to that risk. Therefore, resistance to fire propagation is included in the type-testing required in IEEE 383. With respect to aging and life assessment, the challenge is simply to demonstrate that aging effects are not causing cable systems to become more prone to fire propagation. The demonstration can make use of large-scale IEEE 383-74 type-tests of preaged cable and connections or make use of laboratory tests of oxygen index, thermogravimetric analysis, etc., to show that component polymers are unchanged or decreasing in flammability with age.

13.3 Degradation Sites

Aging effects on cable system components can become degradations of concern when the nature and severity of the changes jeopardize the required safety performance under either normal or DBE conditions. The latter condition is more critical because of the potential for high-risk common-cause failures. Cable systems are distributed widely throughout the containment. In order to make life assessment manageable and economical, it is necessary to focus on those locations where aging stressors are most severe and, therefore, degradation is most probable. If those locations are free of degradation, then the less severely stressed portions of the system are likely to be in good condition. A complication of that approach results from the possibility that some of the locations that are difficult to access are those where stressors may be most severe. Examples include areas where power cables pass through fire stops, areas in terminal boxes where cables are heated by their connection to high–temperature equipment, and areas in narrow passages containing both cables and hot piping. In such cases, a combination of experience and analysis may be a practical substitute for direct temperature or radiation monitoring.

Four considerations that may help in identifying potentially serious degradation sites are (a) maximum environmental severity, (b) susceptible cable or connection designs, (c) physically demanding installation configurations, and (d) records of experience. Although it is listed as a separate consideration for emphasis, experience helps to identify the most important sites associated with the other three considerations. Table 13.4 lists some of potential degradation sites for several cable system components.

Failure statistics and results from routine testing of cable systems in a given plant containment may not help pinpoint potential degradation sites. There may be few, if any, failures, or those that do occur may have no relation to aging effects. Better guidance may be obtained from the broader experience of other cables

Table 13.4 Potential degradation sites in cable systems

Component	Degradation Sites	Examples
Cable conductor	Where conductor is exposed to moist or chemical environment, especially at points of connection.	Cable terminals at neutron chamber. Terminal strips in unsealed boxes in moist areas.
Cable insulation	Maximum thermal/radiation areas. High thermal/radiation areas where not protected by jacket or sheath. High side wall pressure points. Under cracked jackets in intimate contact.	Connections to RC pressure transmitters. Motor terminal box. Control rod drive cables. Support points for vertical runs. Angle condulets.
Wire or cable jacket	Maximum thermal/radiation areas. Flexing or vibration abrasion points.	Same as cable insulation. Cables in long conduit runs having pull–bys.
Pair or cable shields	Wet or moist locations. Chemical spill or drip areas. Vibration, flexing, or grounding points.	Paired cables with metallized Mylar shielding. Conduit low points or above seals in conduit runs where condensation can collect.
Cable splice	High moisture area. High thermal/radiation area. Seals to the cable at splice ends.	Junction boxes subject to trapped condensation.
Seal to cable	At entrance to enclosures.	Motor–operated valve terminal enclosure. Terminal strip enclosure.
Connector conductors	Mating surfaces in moist areas.	Connection to RC pressure transmitter.
Connector insulator	High thermal/radiation areas. Where exposed to moisture or other environmental contamination.	Connection to RC pressure transmitter.
Connector seals	High thermal/radiation areas. Mechanical seal pressure points.	Connection to RC pressure transmitter.
Terminal strips	Exposed insulation between the terminal studs subject to dust and then moisture.	Junction boxes with openings or internal sources of dust.

and connections of the same types in the balance-of-plant and from other plants.

13.3.1 Service Experience. The general industry experiences of interest are those that involve test failures, degradation observations, and random failures, although they do not have the safety implications of common-cause failures. Such experiences can provide some insights into overall system weaknesses, including potential failure sites and modes not anticipated in the original qualification program.

A summary of reported aging-related cable and connector failures in selected instrumentation circuits is presented in Table 13.5. The data in Table 13.5 were obtained from generic data bases, including the USNRC's Licensee Event Report (LER) system, the Institute for Power Reactor Operations' Nuclear Plant Reliability Data System (NPRDS), and the S. M. Stoller Corporation's Nuclear Power Experience (NPE) data base. The LER review covers cable and connector failures from 1980 to 1987. The NPRDS review covers about 13 years of data. The NPE review covers about 25 years of data that are available in the public domain. The failures classed as aging related include events in the following categories: corrosion, dirt, defective connector, loose connector, short/grounded, open circuit, and insulation breakdown.

In reviewing the aging-related failures presented in Table 13.5, note that a high percentage of the failures are attributed to connector problems associated with the temperature and nuclear channels. The connector failures are fewer for the pressure and level channels, which may be an indication that the temperature and neutron measurement circuits are more sensitive to signal degradation or are exposed to more severe environments. Further investigation into the relative failure rates of control and power circuits versus instrumentation, and the causes for the same, could be very productive.

Table 13.5. Summary of reported aging-related connector and cable failures from LER, NPRDS, and NPE data bases for selected measurement channels

	LERs		NPRDS		NPE	
Channel	Number of Aging-Related Failures	Aging Fraction	Number of Aging-Related Failures	Aging Fraction	Number of Aging-Related Failures	Aging Fraction
Pressure transmitters	—	—	13	0.07	—	—
Pressure switches	—	—	7	0.02	—	—
Level transmitters	—	—	5	0.06	—	—
Temperature	—	—	21	0.36	—	—
Fission chambers	7	0.41	120	0.56	33	0.52
Proportional counters	6	0.24	—	—	13	0.30
Compensated ion chambers	4	0.29	22	0.42	5	0.26
Uncompensated ion chambers	7	0.33	15	0.18	19	0.58

NOTES:

— = data not available.

Aging fraction = ratio of aging-related failure to the total failures reported.

Although most of the problems were with connectors, a few cable embrittlement events and cable failures were reported. External phenomena such as wear caused by vibration, pinching insulation, and overheating were the main causes of the connector problems. In one case, it was reported that the connector inserts had carbonized on the control rod drive cable and had to be replaced.[8] A case of high ambient temperature degradation of cable was reported at Salem 1 and 2, involving pressurizer power-operated relief valve wiring.[9]

Terminal strips have been a source of problems and are no longer recommended for in-containment use. Study has shown that dust and condensation are the stressors of concern.[10,11]

Problems related to moisture intrusion into electrical equipment were analyzed in a 1984 NRC case study report.[12] Many of the cases cited involved moisture that entered equipment compartments through cables, through seals around entering cables, and through unsealed cable conduits. It is difficult to judge, without a more detailed analysis, whether the ineffectiveness of seals was due to aging changes, to improper design, or to workmanship. As others have observed,[13] LERs are not a very satisfactory source of information for determining the root causes or detailed mechanisms of service failures.

The TMI-2 accident afforded one of the few opportunities to assess the operability of entire cable systems under accident conditions (86°C, 28 psig, and total dose of about 8 x 10^6 rad). The cables were exposed to the severe combined environmental effects of steam, containment spray, a hydrogen burn that caused overpressurization to 290 kPa (28 psig), and release of fission products and traces of fuel into the containment. There was little aging of the cables prior to the accident since the plant had operated for only about one year. However, evaluation of the TMI-2 cables was complicated by the severe environment that remained in the containment after the accident.

Many of the TMI-2 cable analyses were based on comparisons of measured data to expected values, which were obtained from laboratory measurements on identical or equivalent samples of the subject component. In-place test results were obtained over a period of about 5 years on 560 circuits, with 178 abnormalities identified. At the end of the five-year period, 36 circuits were completely failed, 38 circuits were significantly degraded (circuit resistance, insulation resistance, capacitance, and dissipation factor were measured), and 104 circuits showed minor changes. Generally, the data contained evidence of corrosion.

It was concluded that "results obtained from the investigations at TMI-2 support the conclusion that the basic design of nuclear plants is sound and the instrumentation and equipment is inherently rugged."[14] This statement includes the cable system, as well as the connected instrumentation and equipment. The major findings of the DOE Instrument and Electrical (I&E) investigation program relevant to containment cable systems are as follows:

- Most equipment failures occurred during the first 24 hours of the accident and were predominantly a result of moisture intrusion. Moisture intrusion generally occurred at the electrical penetration to a device. Some items of Class 1E and safety-related equipment were affected by moisture intrusion; however, they were generally more resistant to moisture than nonqualified equipment.

- The hydrogen burn did not damage the nuclear plant instrumentation and electrical components (no functional loss).

- Early failures of some equipment that were not qualified as Class 1E or safety-related were caused by improper installation or maintenance activities, which in turn allowed moisture or spray penetration.

13.4 Aging Mechanisms

Section 13.2 discusses and lists stressors of importance to aging of cable systems. This section describes how those stressors affect particular materials or components in ways that may lead to the modes of aging-induced circuit failure described in Section 13.5.

13.4.1 Polymerics.

General Discussion. In the presence of oxygen, thermal and radiation stressors cause complex chemical changes in polymers. Each stressor causes both scissions of and cross-linking between the long-chain molecules of the polymeric structure. Other ingredients in the original compound, as well as moisture and chemicals diffused in from the environment, may influence the nature or rate of the chemical reactions. Some of those ingredients (antirads, antioxidants, and thermal stabilizers) will slow the rate or delay the start of adverse aging effects, while others can accelerate them. The most observable aging effects resulting from changes in the molecular structure of most rubbers are gradual changes in mechanical properties. Ethylene–propylene rubbers (EPRs), chlorosulphonated polyethylenes (CSPEs), neoprenes, and silicone rubbers all experience these changes. Chain scissions make polymers softer, weaker, and less elastic (cheesey). Cross-linking produces hardening and stiffness. The two responses take place concurrently, and being somewhat opposite in character can sometimes cause very complex patterns of measured property changes over a long period of aging.[15] In addition, there are the more subtle but significant effects of shrinkage, outgassing, and increases in density that may take place.[16] Some plastics and vulcanized compounds have very slight physical aging effects for a substantial time and then change rapidly as the apparent result of depletion of stabilizing agents (antioxidants). Other compounds experience rapid changes early in life, but the rate of change decreases in time. Specific compounding additives and processing variables determine aging characteristics as much as the base polymers.

Some examples of the effects of radiation and temperature on the tensile properties of various materials are shown in Figures 13.4, 13.5, and 13.6.[17] Figure 13.4 presents results for polyvinylchloride (PVC) and low-density polyethylene compounds in air and nitrogen environments. The change in elongation of both the PVC and low-density polyethylene material subjected to combined radiation and thermal loadings is significantly greater in air than in a nitrogen environment. In fact, there is little or no rate of degradation in a nitrogen environment. Also, the PVC degradation rate in air decreases as time increases, whereas the degradation rate for polyethylene materials (once degradation is initiated) is higher and remains about constant. Figures 13.5 and 13.6 show that temperature, as compared to radiation, plays a dominant role in the degradation of the tensile properties of neoprene and hypalon compounds, respectively. In addition, the neoprene degradation rate is significantly greater than the hypalon degradation rate.

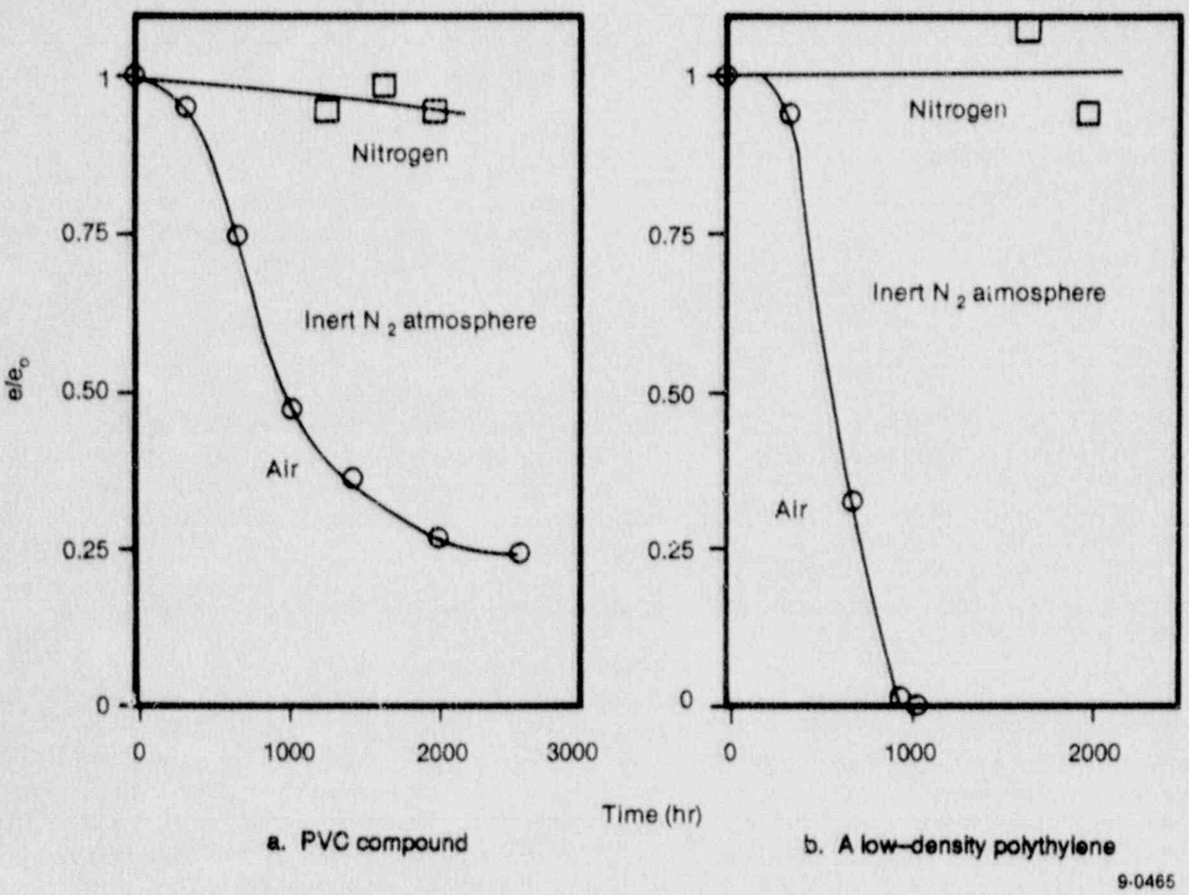

Figure 13. 4. Tensile elongation results in combined radiation/thermal environments of 40 Gy/h plus 80° C in air and nitrogen.

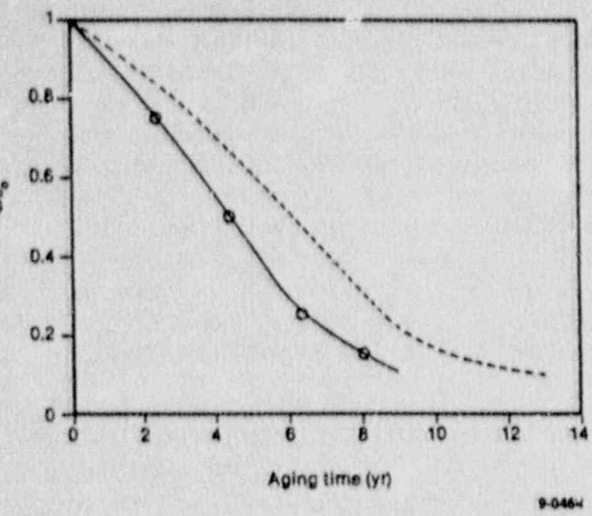

Figure 13. 5. Extrapolated methodology predictions for the time-dependence of the elongation of neoprene at 45°C (113°F) plus 0.2 Gy/h (solid curve) and extrapolated thermal-only predictions at 45°C (113°F) (dashed curve).

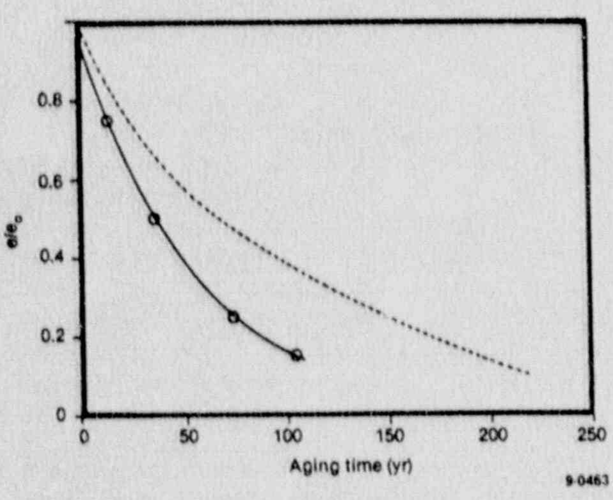

Figure 13. 6. Extrapolated methodology predictions for the time-dependence of the elongation of hypalon at 45°C (113°F) plus 0.2 Gy/h (solid curve) and extrapolated thermal-only predictions at 45°C (113°F) (dashed curve).

The aging mechanisms that affect the *electrical properties* of polymeric compounds are diffusion and chemical reactions that inject or leave electrolytes, charged ions, or other molecular debris in the structure. Those materials increase the dc leakage currents (lower the insulation resistance) and increase ac losses of the compound.

In addition to the cumulative changes in electrical properties noted above, any rise in temperature or radiation dose rate causes immediate and substantial increases in leakage currents and ac losses.

Research has been conducted over many decades on the prediction of the long-term electrical and mechanical property changes of polymers subject to thermal and radiation stressors. Consequently, a technology evolved with a broad base of primarily empirical experience. Experience generally supported the additive nature of the thermal and radiation effects and the validity of using laboratory-accelerated aging to predict long-term behavior. However, sometimes there was a decided lack of good predictability.[a] Some of those cases were caused by synergistic effects, oxygen diffusion limitation, and sequential testing factors.[2] Recent research is providing (a) improved procedures for identifying when older sequential/additive techniques of accelerated aging are not valid and (b) more complicated but more accurate techniques of life prediction and accelerated age conditioning (preaging) for qualification tests.[17] Limited oxygen diffusion into materials can have a major effect on the aging rates of polymers, particularly under accelerated aging conditions. Techniques for estimating whether that would be an important factor are being developed, and laboratory methods for detecting the presence or absence of diffusion effects are well-established.[16]

A note of caution is appropriate in any discussion of the characteristics of compounds used in cable extrusions. Many properties of a generically named material such as EPR, XLPE, or CSPE can vary widely, depending upon the composition of the base polymer, compounding ingredients added, and processing factors. All compounds have from three to 12 or more additives that aid in processing, lower the costs, or deliberately enhance or suppress certain properties. Also, distinctions between the generic classes are blurred by the recent trend of manufacturers to blend different base polymers to create desired final properties. The generic name of the final compound then becomes rather arbitrary. Therefore, it is not appropriate to make precise statements about the behavior of generically named materials. Specific properties are assignable only to specific compounds.

Insulating Compounds. The aging mechanisms noted above will eventually reduce the elasticity (elongation at break) of insulations and usually make

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a. IEEE P775, now in preparation, gives further historical background on multifactor aging work.

them harder. There is the danger of cracking when the initial elongations, typically 400 to 800%, are reduced to 10 to 15%. Cracking could occur if the cable is moved, or if there is sufficient compound shrinkage from aging, or if the insulation is strained from cable shrinkage in the cool portion of a temperature cycle.

Before the aging-related hardening of insulation occurs, there is an extended period during which the insulation (and jacket) of cables and connections are susceptible to creep deformation when high temperatures soften compounds and they are subjected to high deformation pressures. As the cable ages, the compounds become firmer and less susceptible to such deformation.[6]

Plastics that melt (polyethylene, PVC) or compounds with a large component of crystalline structure, such as XLPE, become much softer and prone to creep when the temperature rises above their transition temperatures of between 100 and 120°C (212 and 248°F). Fillers can mitigate that effect to a limited degree.

Moisture (high humidity, steam exposure, or submersion) may influence some thermal/radiation/oxygen-induced chemical reactions. Both beneficial and detrimental effects have been reported.[a] Research into the synergistic effects of moisture with other aging stressors has been limited because of the complexity of the multifactor aging chemistry and an inability to accelerate the effects of high humidity. Kapton[b] insulation has a definite sensitivity to moisture, as evidenced by field failures.[18] The majority of failures have been with Navy aircraft wiring where large bundles of cables are subject to vibration chafing, high humidity, and condensation collecting in the bundles. Hydrolyzing and brittle fracture of the Kapton on the wires cause electrical breakdown leading to electrically enhanced fires. Although the cable configuration and electrical power sources are very different in nuclear containments so that danger of fire as experienced in aircrafts is remote, electrical failures have been reported. Such failures have apparently resulted from mechanical abuse of bare Kapton-insulated wires during installation or maintenance activities combined with a high-humidity environment. Kapton is also readily degraded by alkaline solutions such as those used in some containment sprays. Test work over the years has shown that with most compounds, 100% humidity is more damaging than submersion, and that submersion in distilled water is more damaging than in water with low or high concentrations of common salts. Containment spray solutions have not been reported as any more damaging to polymers than tap or distilled water (with the exception of alkaline sprays attacking Kapton).

It is well-known that moisture effects during LOCA testing have caused cable insulations (and jackets) to degrade and fail.[19,20] Therefore, there is more than the brittle fracture mode of failure that life assessments should target (contrary to many current practices). What is not known and has apparently never been investigated is whether a long period of aging in high-humidity or wet environments will make polymers more susceptible to moisture degradation during DBA exposure.

The *electrical properties* of the cable and connector insulations used in containments change relatively little at normal operating temperatures as a result of thermal and radiation aging during their qualified lives. Some insulations in moist environments are subject to changes in electrical properties that can degrade performance of sensitive circuits. In general, those effects include an increase in dc leakage, dc and ac capacitance (cable impedance change), and in ac losses. The aging changes caused by moist environments and thermal/radiation exposure should be considered along with the similar and additive adverse effects caused by momentary rises in temperature or radiation level in order to assess the full impact of the total environment on circuit operability during high-stress periods.

Direct chemical interaction between polymers and copper can lead to polymer degradation over a long period. Such effects have been observed in high-voltage cables where high electrical stress creates a sensitivity to the interaction, and in communication cables where thin insulation walls and the long circuit lengths exaggerate the effect. This degradation has not been reported in nuclear plants, but it is a potential aging effect of concern especially for those cables with thinner insulations. It is not known whether the high stresses of a DBA and post-DBA period would accelerate the effect enough to give rise to common-cause failures.

The aging effects of the sustained high-level, DBE-related stressors are simply an acceleration of

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a. Several peroxide-cured EPRs have been noted as improving (rising) in insulation resistance after an extended period of 90°C water immersion.

b. Mention of specific products and/or manufacturers in this document implies neither endorsement or preference, nor disapproval by the US. Government, any of its agencies, or EG&G Idaho, Inc., of the use of a specific product for any purpose.

the normal aging. The momentary effects of high-level stressors are important in considering the potential modes of failure discussed in Section 13.5. Water sprays associated with DBEs or those accidentally released into containment apparently have not caused special aging effects on polymers (except Kapton) but may trigger and sustain degradation through corrosion of metals.

Jacket Compounds. The aging mechanisms in polymeric jacket compounds are very similar to those of insulations. The performance properties of greatest importance in jackets are mechanical and fire resistive rather than electrical. Experience of the nuclear power industry to date indicates that the sensitivity of jacket compounds to mechanical aging effects is usually greater than that of the underlying insulations. That observation is supported by laboratory testing of material samples as well as completed cables. Like insulations, the change in properties of elasticity and hardness is not of concern in jacketing compounds until changes cause very low elongations, which could result in cracking.

Unaged or young jackets, when subjected to high temperature, temporarily tend to become softer and more susceptible to slow permanent yielding (creep) under pressures of distortion. As the compounds age, that tendency is usually counteracted by long-term mechanical aging effects of hardening so that performance under subsequent high thermal stress improves.[6]

The effects of moisture on jackets are similar to those described for insulations. However, diffusion of moisture through a jacket is more of a problem because of their basic function as a protective barrier. While all polymers transmit moisture to varying degrees, many jackets do so at high rates, caused by the prevalent use of heavy loadings of fillers for mechanical and fire-resistive purposes. Multiconductor cables have air spaces in their interstices. If such cables are subject to conditions of 100% humidity over periods of weeks to months, those spaces can become moist and, finally, waterlogged. Metallic barriers are the only effective barriers that maintain dry the inside of a cable or connection subject to continuous high humidity. An exception is power cable with internal heating from load currents, which creates a thermal gradient that can effectively pump moisture outward.

Chemicals moving into jackets from interfacing materials can also strongly affect the mechanical properties of polymeric jacket materials. Oils and plasticizers will cause affected jackets to become much more susceptible to creep under pressure.

Connections/Seals. The insulation and polymer coverings (jackets) of connectors and splices have the same aging mechanisms as described above. The seals of various connections have aging effects closely related to the polymeric compound or metal interfaces being sealed. Aging mechanisms of compound creep, loss of elasticity and shrinkage, and of metal surface corrosion are those most pertinent to the failure modes of connection seals. When moisture enters connector internals, corrosion of electrical contact surfaces will, in time, interfere with the circuit current flow. The rate of degradation from corrosion will increase with the presence of different metals and with contamination in the water.

13.4.2 Metallic Components. Because cable systems are relatively passive, their metallic components have limited aging mechanisms. Those mechanisms with the potential to cause circuit failures are corrosion in the presence of moisture, or fatigue, wear, and fastener loosening caused by flexing, vibration, or repeated separation of connections.

Moisture entering cables as a result of breaks in or diffusion through the jackets will initiate corrosion of shields. The thin metal coating of metallized Mylar tapes may degrade rapidly (days or weeks). Metal foil and woven braid shields will degrade over longer periods (months to years). Moisture within cables and seepage through the broken seals of connections may lead to the corrosion of connector contacts.

The majority of corrosion or mechanical aging effects occur over long periods of time, leading to random failures during normal service. However, common-cause failures could occur where a DBE has given rise to the sudden intrusion of water into the more corrosion-sensitive components. The loss of continuity of metallized Mylar and, possibly, wire braid or foil shields during a post-DBE period would raise the noise level in the cable circuits. The functional failure of the circuits would depend on their sensitivity to noise. Similarly, intrusion of water into connector contacts resulting from a DBE might, after time, add series resistance to a circuit and possibly induce galvanic voltages. Again, functional failure would depend upon circuit sensitivity to these changes. Any such failures, together with connection failures caused by accident-related flexing or vibration, would become common-cause failures.

13.4.3 Mineral-Insulated Cable. MI cable systems are especially designed for high-temperature and radiation environments. They contain few or no organic components, so there are no appreciable aging effects induced by the thermal/radiation/oxygen stressors of normal service. Some MI connectors at cable terminals use silicone rubber for seals. However, any compromise of the hermetically-sealed system, which allows exposure of the hygroscopic insulation to even low humidity air, will decrease the insulation resistance (increase leakage), which could result in degradation of circuit function.

The stressors of importance to MI cables are those that can cause breaks in the metal sheath or in environmental seals at connectors. Thus, the stressor of major concern is component movement from flexing or vibration, which can cause abrasion, sheath fatigue cracking, and loosening of connector seal fittings. Thermal cycling is another stressor that can compromise system seals that are not assembled with adequate care.

13.5 Potential Failure Modes

The ultimate failure of cable systems results from a disabling of the electrical circuits (cable propagation of a fire is the unrelated exception). Depending on the particular circuit functions, modes of failure of the cable system include the following:

1. Increased series resistance (an open circuit being the extreme case)
2. Increased leakage current (decrease of insulation resistance)
3. Grounding of a conductor
4. Short circuit between conductors
5. Large changes in ac losses or capacitance (impedance change)
6. Spurious signals from electrolyte or thermoelectric effects
7. Increased noise pick up (shielding or grounding problems).

In general, metallic conductor and connector components of cable systems possess characteristics that relate to the occurrence of circuit failure modes 1 and 6; characteristics of insulating components relate to modes 2 through 5; and the properties of jacket and shielding components relate to modes 5 and 7. Major changes in the properties of cable system components as a result of aging followed by momentary high stressors are the cable system failure modes of greatest concern in this life assessment study.

The sensitivity of operating electrical circuits to changes and noise in the cable system vary widely, depending on the connected devices and the required accuracy of those devices. Proper analysis of the acceptability of cable performance during or after DBEs must be based upon realistic circuit tolerance figures. Unfortunately, such data were largely unavailable for years and still may not be widely available.

Table 13.6 lists several examples of failure modes that could be important to cable systems. The examples illustrate the variety of situations and sequential conditions that should be considered in the life assessments of containment cable system components. IEEE 323-1974 and IEEE 383-1974 specifically aim at such failure modes as new or aged cable insulation electrical breakdown when the cable is subjected to a LOCA environment. Therefore, such failure modes are not included in the examples of Table 13.6. If there are cables that are not adequately qualified to those standards, they will require special case-by-case considerations to assess the remaining life, based on the original life evaluation and its present acceptability.

Aging changes in the insulation of cables and connectors have often been of greater concern than the aging effects on jackets or on the connection seals that are made to jackets. However, considering the importance of jackets in the protection of conductors and insulation from environmental stressors, jackets may be most important in preventing common-cause failures. Laboratory-accelerated aging programs and inservice experience have shown that degradation of nuclear cable jackets to the point of brittleness is normally more rapid than degradation of the insulation under them.[2] Concerns over jacket and seal degradation detection are discussed in Section 13.6.

Common-mode and common-cause failures are important safety concerns because such failures can potentially disable redundant trains and diverse paths for safety-related functions. Some common-mode failures, such as Example 4 in Table 13.6, may not be triggered by a single event but may happen at random after a long period of normal operation. Such failures are of less concern than those in Examples 1 through 3. In the latter cases, age-degraded cables and seals could be triggered to circuit failures by a common event (cause) through either common or diverse paths (modes).

Table 13.6 Examples of potential cable system failure modes

Aging Degradation	Initial Step Toward Failure	Possible Consequences or Complications	Circuit Failure Mechanism
1. *Jacket.* Thermal, radiation aging leads to embrittlement.	Compound shrinkage or cable motion cracks jacket.	A. Moisture enters and corrodes an opening in the shield or introduces added grounding points.	Noise or cross talk interferes with signals.
		B. Jacket adheres to insulation and propagates a crack through it (single or multi conductor cable).	Immediate ground if wet. Incipient ground if dry.
		C. Water enters M/C cable (normal or accident condition) and propagates along the cable.	Compromise splices of some designs. Compromise connectors of some designs. Compromise terminal strips.
2. *Seals.* Thermal, radiation aging result in compound creep then hardening.	Interface pressures drop. Shrinkage or thermal cycling opens seal.	Water enters M/C cable (normal or accident condition) and propagates along the cable.	Compromise splices of some designs. Compromise connectors of some designs. Compromise terminal strips.
3. *Insulation and Jacket.* Thermal and radiation aging drops wet insulation resistance value.	LOCA saturates the inside of cables by diffusion through jacket.	A. Additive effect of aging, moisture, high temperature, and radiation dose rate increases leakage current.	dc instrument or control circuits in error or inoperative.
		B. Above stressors increase ac losses to high value.	ac or pulse signals seriously affected.
4. Maintenance program connector disconnections leave poor pin contact.	Series resistance of circuit initially is increased slightly.	Oxidation/corrosion of loosely mating surfaces increases contact resistance rapidly after design-basis event.	Circuit inoperable when needed with partial or complete open.

Service experience and qualification test failure information could be valuable sources of insight into potential failure modes. However, analysis of failures by persons knowledgeable in environmental conditions, aging mechanisms, failure modes, and circuit functional requirements is necessary for properly relating normal service or test information to the potential for common-cause failures during an accident. Collecting cable system failure data by general categories or trending failure rates may have value in decisions related to replacement of components, based on economics (availability rates), but is of very little value in assessing safety risks from common-cause failure induced by DBEs or in assessing the remaining useful life in relation to the original qualified life of cable systems.

13.6 Inservice Inspection, Surveillance, and Monitoring

The previous sections of this chapter have described the cable system components, the stressors acting on those components, and the aging mechanisms and potential failure modes that may result. Life assessment requires observation of cable system environments and/or component age condition, together with an analysis of such observations compared with those available from the original or a renewed qualification program. In this section, we note the current environmental and cable system condition monitoring practices, those that are being developed, and those that might be developed to improve the life assessment of cable systems.

13.6.1 Inservice Inspection Requirements. The USNRC has no published inspection requirements specifically targeting cable systems. Several bulletins have alerted utilities to check for weaknesses that have occurred at one or more plants. Examples of those weaknesses are physical damage to silicon rubber insulated cables,[21] misapplication of shrink tube splice covers,[22] degradation induced by local heat sources,[23] and abuse/degradation of Kapton-insulated wires.[24] To date, no continuing inspections have been required for in-containment cables. Routine visual examinations of open runs, terminal areas, and areas of known local high stressors are recommended as a maintenance procedure to detect signs of abuse or degradation.

13.6.2 Current Condition/Environment Monitoring Practices. Both current practice and regulatory recommendations have been directed exclusively toward situations where problems have occurred or where problems are especially suspected. Routine surveillance is limited because much of the cable in a system is hidden from view; a cable system is a relatively passive system and standard industry insulation resistance tests would be costly and produce little useful information.

Insulation resistance (IR) tests are the only standard tests conducted in the industry on low-voltage power station cables. The moderate use of IR tests is generally confined to applications after equipment installation, when work is being performed on a circuit or cables have been disconnected, or when the condition of a cable is suspect for some other reason.

IR tests can be revealing in certain cases and relatively useless in many others. Measurements are very temperature sensitive. An 8 to 10°C (46 to 50°F) temperature rise will halve the measured IR value. Therefore, knowledge of the temperature throughout a cable run is necessary for proper interpretation of a reading, but that information is usually unavailable. Nonshielded cables, unless wetted, have an indefinite ground path that will grossly affect test results. Therefore, IR tests are useful (a) where temperatures are known (or constant over time) and cables are of the shielded design or wet; or (b) where two or more conductors are in close proximity under identical conditions so that IR values for the conductors can be compared to detect unusual differences.

No in situ electrical testing has yet been successful in detecting gradual aging changes in polymeric cables caused by thermal and radiation exposure in nuclear plants. The effects of water or very high humidity can be detected with some insulations, but its usefulness for nuclear cables, other than MI cables, has not been verified. IR tests can detect some types of gross installation damage, cracking of insulation, and the breach of connector seals, provided there is enough humidity or moisture to make the exposed leakage surfaces conductive. Breaks in insulation systems that are dry and clean are normally not detectable with IR tests of 1000 V or less.

Some utilities use high-voltage (greater than 100 V) dc tests on low-voltage cables that are suspected of having major mechanical damage, but such tests are not presently used for detecting aging degradation.

A few utilities have adopted a monitoring procedure (discussed also in Section 13.6.5) involving IR tests, capacitance, dissipation factor, series circuit resistance and a pulse reflection test (time domain reflectometry) to detect changes in impedance along the circuit.[25] The task of programming tests, storing data that are generated, and comparing measurements over the years is made manageable by computer control of the testing and logging of the data obtained. That monitoring procedure has proven particularly useful in detecting and locating discrete changes in the series resistance of circuits at corroded or loose connectors, but it has not been proven of value in detecting gradual aging effects on insulations, jackets, or degraded seals that are dry.

Aging changes that lead to eventual circuit failures or near-failures are normally not observable until the troubled component is isolated for dissection and analysis. Until much more experience has been accumulated or new measurement techniques are developed, it will not be possible to electrically monitor the aging of in situ cable systems in a way that relates to the preaging carried out in qualification programs.

13.6.3 Environmental Monitoring. Monitoring of the containment environment may aid in the assessment and extension of the qualified life of cable systems.[26] With the difficulty and limited success of present in situ testing methods in monitoring aging changes, one of the more promising approaches to life assessment is to compare the actual normal operating stressors to those on which the initial qualified life was based. If the actual stressors are greater, the initial qualified life should be shortened. More generally, normal stressors are found to be lower than assumed, which may justify the extension of the qualified life.

If the environmental monitoring can be detailed enough to map the more critical areas of the containment for temperature and radiation levels over time, that would provide another tool for accurate and cost-effective life assessments. Use of remotely-controlled, infrared survey instruments is a powerful method for locating very localized cable system hot spots. A utility can then concentrate its efforts on the hot spot locations and if components in those locations have adequate qualified lives, then those same components in all other areas will have fewer thermal and radiation aging effects and longer lives. Components in the hot spots can be inspected, tested, or sampled at moderate cost to provide information relevant to all other such components in the containment (and balance of plant).

13.6.4 Standards. There are no published standards applicable to the power industry for in situ monitoring of aging changes in low-voltage cables other than insulation resistance.[27] There are a number of physical, electrical, and chemical laboratory test methods that have been used. None of those test methods have been used in evaluating cables in place because they are destructive and must be applied to samples, using laboratory equipment.

13.6.5 Developing Technologies. Several programs are under way to develop electrical and mechanical techniques for cable-condition monitoring to track gradual aging effects; such techniques must have the potential for relating to qualification preaging programs. The Electrical Circuit Characterization and Diagnostic (ECCAD) system is the only new test monitoring program that is presently used in some nuclear plants. This computer-controlled test and data logging system was developed as a result of work done by EG&G Idaho, Inc., at the TMI-2 accident site.[25] In addition to automating the program, the ECCAD system incorporates circuit series resistance measurements and time domain reflectometry. These nonstandard tests have been reasonably effective in finding the presence and location of circuit discontinuities. The effectiveness of ECCAD in tracking the state of aging of insulation or jackets has not yet been demonstrated. In fact, it is likely that ECCAD will not be an effective tool for that purpose.

Several new aging assessment test methodologies that are or might be under development for cable system monitoring include the following:

- A number of studies are under way to investigate different aspects of accelerated and natural aging of polymers used in nuclear plants in order to develop a better fundamental understanding of those aging processes and their proper relationships. Studies include EPRI-sponsored projects at the University of Connecticut, the University of Virginia, and the University of Tennessee.

- A mechanical cable indenter that may be effective for surveying overall cable environmental aging severity in a containment and for tracking the aging of cable jackets or exposed insulations with reference to a preaged condition in qualification is being developed. The indenter is an EPRI-sponsored project at the Franklin Research Center.[28]

- Time domain spectroscopy is a technique of applying a dc step voltage to a cable, analyzing the frequency spectrum of the resulting current flow, and deriving the cable insulation capacitance and loss characteristics as a function of a wide frequency range. It is presently in the laboratory evaluation stage. Early data indicate that it distinguishes between thermal- and radiation-induced insulation changes better than other electrical means tried to date. Work on this methodology is being performed by the National Institute for Standards and Technology (NIST, formerly NBS).[29]

- Partial discharge detection methods for finding insulation defects are customarily used for medium- and high-voltage cables. New concepts of these techniques that are applicable to nuclear plant low-voltage cables are being investigated by NIST and in an EPRI-sponsored project at the University of Connecticut. Reports of success in laboratory trials have not yet been published, so field use is still a distant prospect.

- A new method of temporarily shielding nonshielded cables located in conduit without the use of water is being developed. EPRI is developing an ionized gas technique in order to avoid the use of water in making electrical tests of nonshielded cables.[a]

- NRC- and EPRI-sponsored projects at Sandia National Laboratory will perform tests to identify which of the many previous electrical and mechanical cable monitoring tests produced data that correlate with cable performance under LOCA/MSLB stressor conditions. The previous Sandia condition monitoring tests were conducted on a wide variety of preaged cables and were performed in situ or in the laboratory. New tests will include preaging of cables at 100°C for 3, 6, and 9 months to represent 20, 40, and 60 years at 55°C ambient with simultaneous radiation to 50 Mrads. The preaging will be followed by 110 Mrad of accident radiation before accelerated LOCA testing. Cables with local abuse and damage will also be included in the tests.[b]

- Jacket integrity testing through air flow monitoring is a potentially valuable technique that has been used infrequently by cable manufacturers but has never been reported as having been used by utilities. It may be applicable to cables with internal air passages under the jacket to detect whether or not the jacket (or jacket and insulation) is (are) cracked or mechanically damaged. It may also be useful to determine if end seals are hermetic. There are no programs at present to explore the usefulness of this technique as an in situ method of verifying cable insulation or jacket integrity.

- Chemical analysis of surface scrapings from cable jackets is a method of possible value in life assessments. Spectroscopic equipment requires only minute quantities of material. Spectroscopic analysis has been used repeatedly for tracking age-induced chemical changes in polymers in research projects unrelated to nuclear low-voltage cables.[15]

13.7 Aging and Life Assessment Programs

The sections above in this chapter discuss the major elements involved in any life assessment program for cable systems in containment. This section relates some of those elements to program strategies for determining the useful life of cable systems.

13.7.1 General Discussion. The useful life of cable systems in Class 1E containment service is the qualified life, which is the one demonstrated in the nuclear qualification program. Only the qualification program addresses the issue of adequate performance during possible seismic or accident events. Thus, qualified life has to be the starting point for any life assessment of Class 1E cable systems. Uncertainties in the initial qualified life resulting from documentation problems or from evolving regulations are not addressed herein. Issues raised as a result of evolving technology and experience are noted in Section 13.7.5. Although the focus of concern for in-containment cable systems is avoidance of common-cause failures, there is also a safety concern over random failures occurring during normal service in 1E and many of the nonsafety related circuits. Cable system failures frequently result in scrams or other stressful challenges to the safety systems, which thereby increase the potential for sequential failures. It is advantageous to address aging in both 1E and nonsafety related cable systems to increase the useful database and, through improvements to both, to directly improve plant availability and indirectly improve safe reactor operation.

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a. G. Sliter, private communication, 1989.

b. Larry Bustard, private communication, 1989.

13.7.2 Evolution of a Qualification Basis. IEEE 323–1971, a trial use standard, was the industry's initial equipment qualification standard applicable to nuclear cable systems. It did not specifically address aging or life determination issues. The 323–1974 revision did address those issues and the documentation of the aging program used with the preferred type testing approach to qualification. Concurrently, IEEE 383–1974 was issued covering the type testing of cables for nuclear qualification. That standard provided specific procedures for the preaging of sample cables and connections before type testing for LOCA. It also included flexing (bending) of cables after aging (to test their ability to withstand seismic or other sources of movement without cracking) and testing for fire propagation.

USNRC Regulatory Guide 1.89 has been issued endorsing IEEE 323–1974 (with certain exceptions and supplements) as an acceptable way of meeting the mandatory qualification requirements. Regulatory Guide 1.131 has similarly endorsed IEEE 383–1974.

Current environmental qualification requirements related to aging and life of equipment, including cables, are contained in three documents: NUREG 0588 issued December 1979, Division of Operating Reactors (DOR) guidelines issued November 1979, and 10 CFR 50.49 issued January 1983. NUREG 0588 provides a set of requirements for plants with construction permits before June 1974 and a more stringent set for plants with permits after June 1974. The DOR guidelines provide requirements for plants with operating licenses issued before May 1980, and 10 CFR 50.49 provides requirements for all plants with operating licenses issued after February 1983. Therefore, plants designed, constructed, and licensed at different times have different guidance and requirements for the preaging, type testing, and documentation for cable system component qualification. For example, in contrast to guidelines for later plants, guidelines for earlier plants do not require that cable samples for LOCA testing be preaged before testing. Also, different samples are permissible for demonstrating resistance to aging stresses and resistance to a LOCA. Absence of voltage breakdown during the LOCA test is considered acceptable with no examination or postenvironmental test to demonstrate margin. Documentation required for the cable qualification of early plants can basically state that the tests were done. No details of test plans, data taken, or quality control measures used are required.

13.7.3 Life Assessment Options. Assessment of the useful life of 1E cable systems in containment is, in effect, a reassessment of the life set forth in the qualification program. Incentives for reassessment include a desire to extend the original qualified life and concern about the validity of the original assessment. The reassessment could logically involve a reanalysis of the revised facts only, using the same logic or rationale that formed the basis for accepting the original qualified life. However, it is unlikely that such a strategy will be acceptable for cable systems installed before the preaging/test methodologies of IEEE 323–1974 and IEEE 383–1974.[30] Therefore, decisions need to be made as to which aspects of aging and qualification practices must be revised to be acceptable and compatible with the technology available at the time of life reassessment.

Strategy options worthy of consideration for assessing the useful remaining life of Class 1E cable systems in containment include the following:

1. Determine the actual cable system environments for comparison with those assumed in the qualification program, then recalculate the qualified life.

2. Determine the actual states of aging of cable systems and compare them with those of the preaged components used in the qualification program, and then conservatively estimate the time remaining before systems reach the preaged condition.

3. Extend the qualified life by removing samples of components from service, add accelerated age conditioning, and verify DBE performance by type–testing (sometimes this is referred to as ongoing qualification or requalification).

4. Obtain representative samples of unaged cable or other components and qualify them for the currently desired life.

5. Replace the components in question. This is not an assessment strategy, but it can resolve the same problems that life assessment addresses.

Option 1 is discussed in some detail in Section 13.6.3. There is concern over extending the qualified life by using only the conservatisms found between the assumed or specified environments and those later determined by observation. There is a valid rationale for including *all* the new factors, favorable and unfavorable, affecting estimates of life to arrive at the most valid net change. Unfortunately, to do so may broaden the scope of the life assessment program into diverse and controversial aspects of the qualification program. Those aspects are not discussed in detail in this study.

Option 2 involves measuring aging effects in cable system components in order to compare the state of aging of inservice cables with that in a qualification program that had involved accelerated preaging. Inservice component measurements need to be made either in situ (methodologies not yet available) or on samples taken from the most severe aging environment to which components of interest are exposed. The necessary comparative data must be obtained either from the original qualification program, from others who have qualified the component, or from new measurements after accelerated preaging of the same type of cable (or other component) is carried out. If unaged components of the same type as those installed are no longer available for duplication of the original preaging, or the cable systems were installed before establishment of current preaging/test methodologies, the relatively costly but very productive Option 3 may still be applicable.

For Option 3, samples of cable from the containment or balance of plant may be carefully removed, subjected to accelerated aging to add to that already accumulated, and then subjected to DBE type-testing. Measurements made after the combined natural and accelerated aging would then become the reference for future comparisons with installed components.

Measurement techniques now available for aging comparison are limited to destructive laboratory types, requiring sample removal. Promising techniques for in situ physical or electrical measurements to assess cumulative aging effects are under investigation (see Section 13.6.5).

13.7.4 Efficiency of Life Assessment Programs. In order to perform a life assessment with a minimum of expense in terms of dollars and worker radiation exposure, life assessment programs should perform the following:

- Assess the normal aging environment as early in station life as possible
- Focus on those cable system components in their most adverse normal environment
- Focus on those cable system components that industry experience indicates have the most severe aging degradation problems involving potential common-cause failures
- Initiate programs of failure analysis and record keeping for all power plant cable system components of the 1E types whether used in 1E circuits or not
- Acquire virgin samples of all Class 1E containment cable system components as soon as possible.

13.7.5 Potential Aging-Related Deficiencies of Qualification Programs. As noted in Section 13.7.3, there are aging-related technical issues in the qualification programs that may need to be addressed if the approach to life reassessment involves the recalculation of qualified life using actual plant aging stress levels instead of those originally assumed or specified. Such issues might include the following:

- Questions about accelerated aging theory and methodologies (extended data extrapolation, synergisms, order of sequence, dose rate effects, oxygen diffusion limitations)
- Stressors in service not included in the environmental qualification program (moisture in normal service, thermal cycling, interface chemical exposures)
- Unanticipated modes of failure (jacket brittle rupture or moisture transmission failure paths, interface relaxation/creep effects)
- Circuit operational requirements not given in purchasing or qualification specifications but later found to be applicable (low leakage current or low noise level limits).

An important issue associated with the use of the current accelerated aging methodology is the validity of Arrhenius type (activation energy dependent) extrapolations. The use of an Arrhenius extrapolation assumes a linear relationship between the log of time and the inverse absolute temperature (or radiation level or other loading). The basic data used to establish the Arrhenius relationship for nuclear power plant cables has been obtained from laboratory oven tests, generally with an air environment, extending over one to two years. The cable preaging before the qualification DBA tests is generally one to seven weeks. The time extrapolation of the basic data to a 40-year end of life is, thus, a factor of 20 to 40. The time extrapolation of the preaging period is a factor of 500 to 2000. The temperature extrapolations will correspondingly be from an oven temperature of 150°C down to a service temperature of ~90°C. As discussed in Section 13.4, polymer aging is a complex chemical/mechanical process dependent on temperature, radiation, oxygen, and other stressors. Large extrapolations may not be appropriate.

13.8 Conclusions and Recommendations

The variety of cable system materials, constructions, installation conditions, potentially age-degrading stressors, and possible mechanisms of failure result in a complex array of situations to consider in assessing residual life. A realistic management of the aging process requires focusing on priority issues.

Those issues are as follows:

- Common-cause failures (CCFs), because they have the greatest potential impact on safety
- System component potential mechanisms of failure that have been revealed during qualification testing
- Mechanisms of failure that have been revealed during normal plant operation and relate to potential common-cause failures.

Table 13.7 is a summary of aging- and qualification-related cable system failure modes and contributing factors judged to be the most likely to impact the safety of some nuclear plants. All are aging related and are potential sources of CCFs following a design-basis accident or submersion event. Therefore, they are of technical concern when making any life assessment of in-containment Class 1E cable systems. Other failure modes may arise or their importance become known as research and experience accumulate.

These summary failure concerns and other factors discussed in the sections above form the basis for the following conclusions. First, conclusions are stated relevant to the technical status of life assessment factors; second, conclusions on life assessment strategies are presented.

13.8.1 Technical Conclusions

- The technical life assessment issues for in-containment cable systems are quite different from those of the balance of plant because of the potential for CCFs that can impact safety during or after design-basis accidents or submersion events and because of the inaccessibility of the containment after such events.
- Age-related changes that impact cable system susceptibility to CCFs are those that life assessment methodologies should target, whether or not those changes were considered in the original qualification program.
- Analytical or sampling/testing methodologies may be technically feasible for life assessment if the proper data and materials are available (see Section 13.8.2).
- There is generally insufficient containment ambient and hot-spot radiation and temperature data to assess the aging rates of cables or connections.
- In situ age-condition monitoring methods are presently inadequate for either cables or connections. Methodologies are being developed for cables, but the current work is not addressing connections.
- Data on measured age-condition parameters of cables or connections that were preaged for environmental qualification tests are generally not available now but can be obtained in some cases. Such data will be an important basis for in situ age-condition monitoring programs as they are developed.
- Failure statistics or trends obtained from normal service are not as useful in life assessments of Class 1E containment cables as they may be for providing guidance to programs for reduction of time-random failures and improving plant availability.
- Failure analyses discussed in the LERs are usually inadequate for identifying either relevant critical aging stressors or the root cause mechanisms of polymer or cable failure.
- Many of the qualification issues that research and engineering or operating experience have brought to light since the writing of IEEE 323 and 383 in 1974 are aging related and should be considered in life assessment programs.

Table 13.7 Summary of potentially important failure modes and degradation factors for LWR containment cables and connections[a]

Failure Modes	Age Degradation Mechanisms	Dominant Aging Stressors	Components	Degradation Sites
Circuit ground or short when subject to condensing steam, spray or water (CCF)[b]	Jacket embrittlement and cracking—propagating through insulation. Bare insulation cracking.[c]	High temperature, O_2 presence, radiation in a few cases, sometimes moisture.	Single and multiconductor nonshielded jacketed cables. Kapton-exposed wires.	Hot spots, terminal areas at hot equipment, proximity to hot pipes, fire stops, exposed susceptible insulation.
Corrosion causes opens in, total loss of, or multiple grounds on shields (CCF, RF).	Jacket cracking or moisture diffuses through jacket and condenses.	Moisture, high temperature.	Shielded coaxial or multi-conductor paired cables.	Moist warm areas, high humidity; near water, steam leaks, or seepage.
Corrosion of contacts. Circuit opens, grounds, or shorts (CCF, RF).	Diffused moisture collects in cable and migrates into connection internals.	High temperature, moisture, and water contamination.	Connections not permanently sealed against cable internal moisture.	Moist warm areas, high humidity, near water, or steam leaks, or seepage
DBA pressure/steam/spray passes into or through connection. Contacts corrode or circuit grounds or shorts (CCF).	Polymer seals (O-rings) or cable polymers cold flow so that seals are not hermetic.[c]	High temperature and/or radiation dose, cable movements, vibration, thermal cycling.	Connections with compression seals.	Hot spots—thermal and radiation, connections where cable is moved.
Peak temperature and radiation during DBA cause excess leakage or losses to disable circuit function or lead to insulation breakdown (CCF).	Thermal and radiation aging leave remanent electrolytes to increase leakage or losses.	Heat, radiation, and moisture diffusion in normal service. Temperature, dose rate, and moisture after DBA.	Cables insulated with halogenated or filled polymers.	General—where exposed to harsh accident environments.
Same as above, except steam condensation and ionizing radiation are prime factors.	Gradual increases in surface contamination.[c]	Accumulations of wettable or conductive surface contamination.	Terminal strips.	Nonhermetic junction or terminal boxes with external or internal dust or contamination generators.
Excessive leakage disables MI cable circuit operation (CCF, RF).	Metal cold flow or loosened threads open hermetic seals to moisture intrusion.	Vibration, repeated movement, thermal cycling.	MI cable connections.	Connections subject to vibration or flexing.

a. The problems listed may have been anticipated and adequately addressed in the original Class 1E nuclear qualification program practices. However, they are ones that should be considered if qualification practices were not complete or rigorous in their application or if considering the extension of the original qualified life.

b. Notations in parentheses indicate potential for common-cause failures after a DBA or submersion (CCF) and for random failures during normal or abnormal service (RF).

c. The degraded condition noted is probably not electrically detectable when conditions are dry.

13.8.2 Strategy Conclusions

- An analytical approach to residual life assessment may demonstrate a qualified life well beyond the initially specified 40 years. That approach is applicable to cable systems with adequate nuclear qualification, including current preaging, type testing, and documentation. It would consist of a reanalysis of the original qualification preaging data, using conservatisms found between the specified and the actual operating (aging) environments and performance requirements.

- To maintain the current level of safety, life assessment programs based on reanalysis should address all new qualification issues that may directly affect the validity of predicting qualified life from the original preaging data. Those would include the ordering of sequential stresses, synergistic effects, dose rate effects, and oxygen diffusion effects.

- Other approaches to life assessment (or backup validation for the analytical approach) include removal of small samples for laboratory test and analysis, obtaining virgin components or removal of sufficient components from the plant for accelerated preaging and type–test (requalification), or use of in situ monitoring techniques under development as they become available.

- During any life assessment program, consideration should be given to the plant–specific potential impact of other qualification issues that may not have been addressed in the original qualification program but are now revealed as possible sources of CCFs. Examples include excessive leakage currents under the peak temperature and radiation after an accident; wet cable internals affecting connections or connected equipment; long–term moisture aging effects on insulation; polymer relaxation (creep) compromising any compression seals used; and loss of or multiple grounds on instrumentation cable shields before or during an accident.

13.8.3 Recommendations. Based upon this study, the following are recommendations for immediate implementation by utilities:

- Immediate steps should be taken by the utilities to monitor containment temperatures and radiation levels and locate and monitor cable system hot spots

- Utilities should establish improved failure analysis and record keeping for all plant cables of the types used in Class 1E service

- Utilities should combine their efforts to obtain component samples for testing and to obtain baseline data on components preaged for DBE tests

- Periodic inspection programs should include careful examinations of connection areas to detect jacket cracking, disrupted or loose seals, signs of corrosion or moisture seepage, and surface contamination of electrical leakage surfaces

- During maintenance activities, disturbance of cable systems should be minimized when moving or disconnecting other equipment. Visual surveillance, temperature and radiation monitoring, and the cleaning of contaminated electrical leakage surfaces at terminals are the only routine activities generally recommended for cable systems to ensure their maximum life.

Recommendations for utility–, DOE–, and USNRC–sponsored research to improve the industry's ability to address life assessment of nuclear cable systems include the following:

- Continue support of projects on promising cable system age or condition monitoring methodologies for both laboratory and in situ uses

- Investigate the sensitivity of existing connections to (a) water migration from connected cable internals, (b) water ingress from polymer pressure seal relaxation/creep, and (c) water ingress from untested combinations of interfacing cable and connection materials with potential incompatibility

- Determine the influence of moist or wet normal aging exposure on the sensitivity of cable or other components to moisture degradation during DBAs

- Determine if a commercially feasible means exists for gathering formerly unreported qualification type test failure data in order to reveal any failure modes with impact on potential common–cause failures.

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14. PRESSURIZED WATER REACTOR AND BOILING WATER REACTOR EMERGENCY DIESEL GENERATORS

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The electricity generated by a nuclear power station generally serves the overall electrical system in that same station, with its numerous pumps, motor-operated valves, and other auxiliaries. When the station is not generating electricity, or in times of electrical disturbances, safety standards require that power be available from external sources over both normal tie-lines and dedicated emergency lines. However, it is recognized that all such resources can fail concurrently, so it is further required that each plant have emergency electrical generating capability on site.

The selection and sizing of such equipment must meet, among other stipulations, the requirements of Nuclear Regulatory Commission (NRC) General Design Criterion 17, Electric Power Systems, found in Appendix A of 10 CFR 50, entitled *General Design Criteria for Nuclear Power Plants*. This requires that the onsite electric power system has sufficient capacity to ensure that (a) specified acceptable fuel assembly design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences and (b) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

Nearly all nuclear plants have met this requirement by use of diesel engine generators, though one plant (Oconee) has made use of hydroelectric units, and at least one plant (Shoreham) has replaced failed engine generators with gas turbines as a temporary measure.

Emergency diesel generators (EDGs) have been selected as the electrical backup because they (a) come in a variety of types and ratings suitable for emergency power, (b) can be started and loaded rather quickly—a key criterion, (c) are considered reliable in starting and in extended operation, (d) are easily installed, and (e) are readily maintained. Most of these attributes have been proven for numerous engine designs over many years of service in a variety of generating plants, pipeline compressor and pumping facilities, and marine, railroad, mining, and other applications. A 1981 EPRI study identifies utility plants with engines proven by extensive experience whose designs might be rather directly transferrable to nuclear EDG application. The study covers over 900 utility-owned central stations, employing some 3000 electricity generating units and aggregating over 5000 MW in capacity.[1] Most of these stations are municipally owned, and many have operated as base-load, continuous-duty plants.

As of a 1985 study, there were more than 230 EDGs in United States nuclear application, usually two or three per nuclear unit, with sizes up to 9000 kW (12,500 hp). These comprise several models and basic sizes manufactured by nine domestic manufacturers: Alco, Allis-Chalmers, Caterpillar, Cooper-Bessemer, Electro-Motive Division of General Motors, Enterprise Engine Division of Transamerica Delaval, Fairbanks-Morse Engine Division of Colt Industries, Nordberg, and Worthington.[2] The relatively small, higher-speed units were more often selected in early EDG applications; however, as nuclear plant sizes and their emergency loads increased, the trend has been toward larger, medium-speed units, some having ratings by the manufacturer of up to 9000 kW, and typical of the engine generators identified in Reference 1.

Each EDG at a plant serves specific essential and non-essential plant loads in an emergency. However, some such loads are redundant. For example, there will be duplicates of certain pumps and each will be served from a different EDG, so that the loss of one unit will not prevent that essential service from functioning. The EDGs are connected to separate switchgear busbars, as are the plant loads being served; there is no common-mode interconnection permitted. In an emergency, the safety system will determine whether one or all EDGs must be started, which depends on the nature of the event or the sequence of events.

These emergency generating units form complete, nearly independent power plants. As such, they are complex aggregations of the prime mover; generator and exciter; auxiliary systems for fuel, lubrication, cooling, starting, intake, and exhaust; switchgear; and controls and instrumentation, including control and power interface with the main plant. Hence, there is broad potential for problems to develop that might thwart or adversely affect their protective mission.

However, despite the fairly large number of EDG units in service and the requirement that all service failures be reported, a 1986 survey of the years 1983 through 1985 reveals a rather low EDG failure rate. In that period surveyed, there were 22,104 starts, planned and unplanned (that is, real demands); only 431, or 1.95% were unplanned, initiated by the emergency monitoring and actuation system. Of those 431 emergency starts, only 2 (or less than 0.5%) aborted in the start phase. Some 223 went on to load–run operation, of which just 4 then failed (or less than 2%). Of the vastly more numerous planned starts, some 81 aborted (out of 21,673, or less than 0.4%), while of the 13,585 that purposely were carried on to load–run, only 134 failed in duty (or 1%). Hence, the Nuclear Safety Analysis Center (NSAC), publisher of the report, claimed that "both the start–phase reliability and the load–run reliability performance are excellent and offer little opportunity for improvement."[3]

Other researchers, however, report slightly different patterns, with somewhat higher unreliability rates. For example, Baranowsky[4] reports 690 EDG failures in 33,500 valid demands in the years 1976 through 1984, a 2% failure rate. Of these, 110 were instances of multiple EDG failure or EDG failure concurrent with unavailability of the other EDGs—a disquieting situation, particularly when considering that there were about 3.5 events per year of total loss of offsite power across the population of nuclear plants, where the EDGs became the only power resource. Some of those outages lasted up to 26 hours. Another study[5] reports that of all Class 1E safety subsystems, the EDG systems were by far the largest single contributor of failures.

EDGs are included in this report because of the obvious safety importance associated with any failure of an EDG to perform its designated function. Various studies have been conducted on them in this connection, some under auspices of the USNRC, others by EPRI and other organizations. Several reports and numerous technical papers and trade articles have been issued, many of which are sources for this chapter, which summarizes findings to date, proposals for action, and the thrust of ongoing investigations. Maximum reliance is placed on the data and evaluations from NRC–sponsored nuclear plant aging research (NPAR) performed by Pacific Northwest Laboratories.[2,6,7] Attention is given principally to those problems which, through analyzed experience or as foreseen by investigators, have had or might have greatest impact on EDG reliability and the relevant means of aging mitigations.

14.1 Description

14.1.1 General Description. EDGs are essentially small but complete electric generating plants, purposefully with little direct interface or dependence on the main generating facilities. Several criteria apply to the selection and design of EDG equipment and facilities,[8,9,10] within which overall plant designers and the EDG suppliers have some latitude in equipment and plant specifications and systems designs, resulting in a broad variety of EDG facilities, controls, and operations. However, they have many characteristics more or less in common, which form the basis for the descriptions and discussions in this chapter.

The primary components are the engine and the directly connected generator, usually mounted on a single structural–steel skid. Primary auxiliary systems [for example, cooling, lubrication and some fuel oil facilities, sometimes an instrument and control panel, and possibly other systems] are mounted usually on the same skid, or on a second abutting skid. Other auxiliary items, such as the intake air filter, exhaust silencer, air compressors and receivers, ultimate cooling facilities, switchgear, static exciter and voltage regulator (if such are included in the design), dc sources, etc., most generally are located elsewhere, and appropriate piping and wiring connections are run as needed. (Sometimes—principally for larger units—engines are set directly on concrete foundations and auxiliaries are field–set and piped, as often is done for comparable nonnuclear installations.)

The skids are mounted on concrete pads in bays or cubicles large enough to house the units and associated off–skid equipment and to provide access for operations and maintenance. The bays are designed to individually isolate the two or more EDGs customarily used at nuclear power plants in order to minimize common–cause failures and protect the plant from external adversities. Such enclosure and physical separation would likely prevent windstorm damage, etc., but if such occurred to one EDG, it would not affect or spread to a companion unit. Likewise, fire, explosion, sabotage, etc., could be avoided or contained.

Figure 14.1, from IEEE–Std 387–1984,[9] is a generic schematic of an EDG facility, its various supporting systems and functional links to the external environment, power systems, and other supporting and control systems. With some exceptions—notably, certain controls and the unit switchgear—all the subsystems discussed in this chapter are shown within

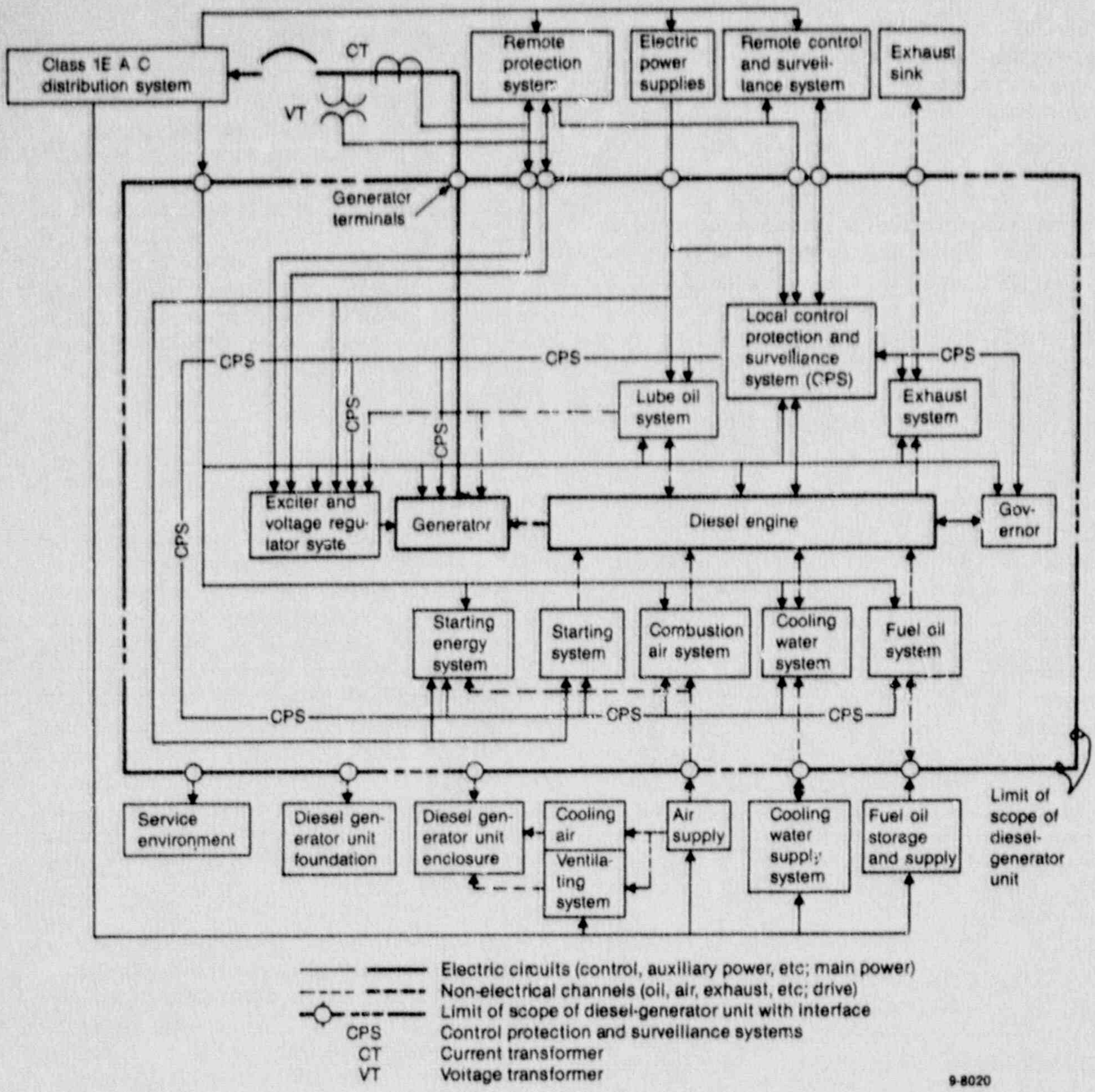


Figure 14.1. Scope diagram of emergency diesel generator (from Reference 9).

the closed boundary of the schematic. Note that the EDG-engineered safety feature actuating system (ESFAS) controls for starting, loading, and load shedding are not within the scope of this report, but design deficiencies and operating failures in this area, some caused by aging phenomena, have been noted by various researchers as one source for both single- and common-mode failures.[4]

A typical nonnuclear engine-generator package is shown in Figure 14.2. Figure 14.3 is a typical nonnuclear plant layout, which provides perspective on minimum spatial requirements for such facilities.

The major EDG components and support systems are discussed in the following two sections: Mechanical Systems (14.1.2) and Electrical Systems and Controls (14.1.3). Additional description and relevant diagrams are presented in Reference 2.

14.1.2 Mechanical Systems

Diesel Engines. All EDGs are reciprocating diesel engines, either of in-line or V configuration,

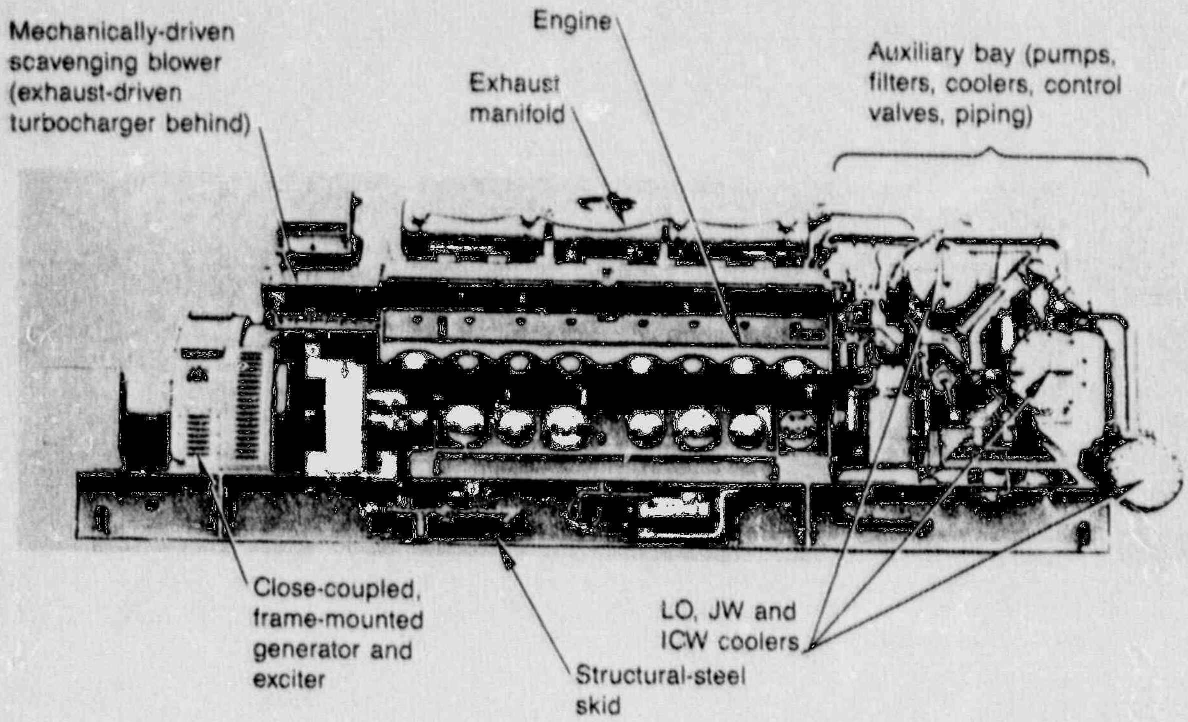
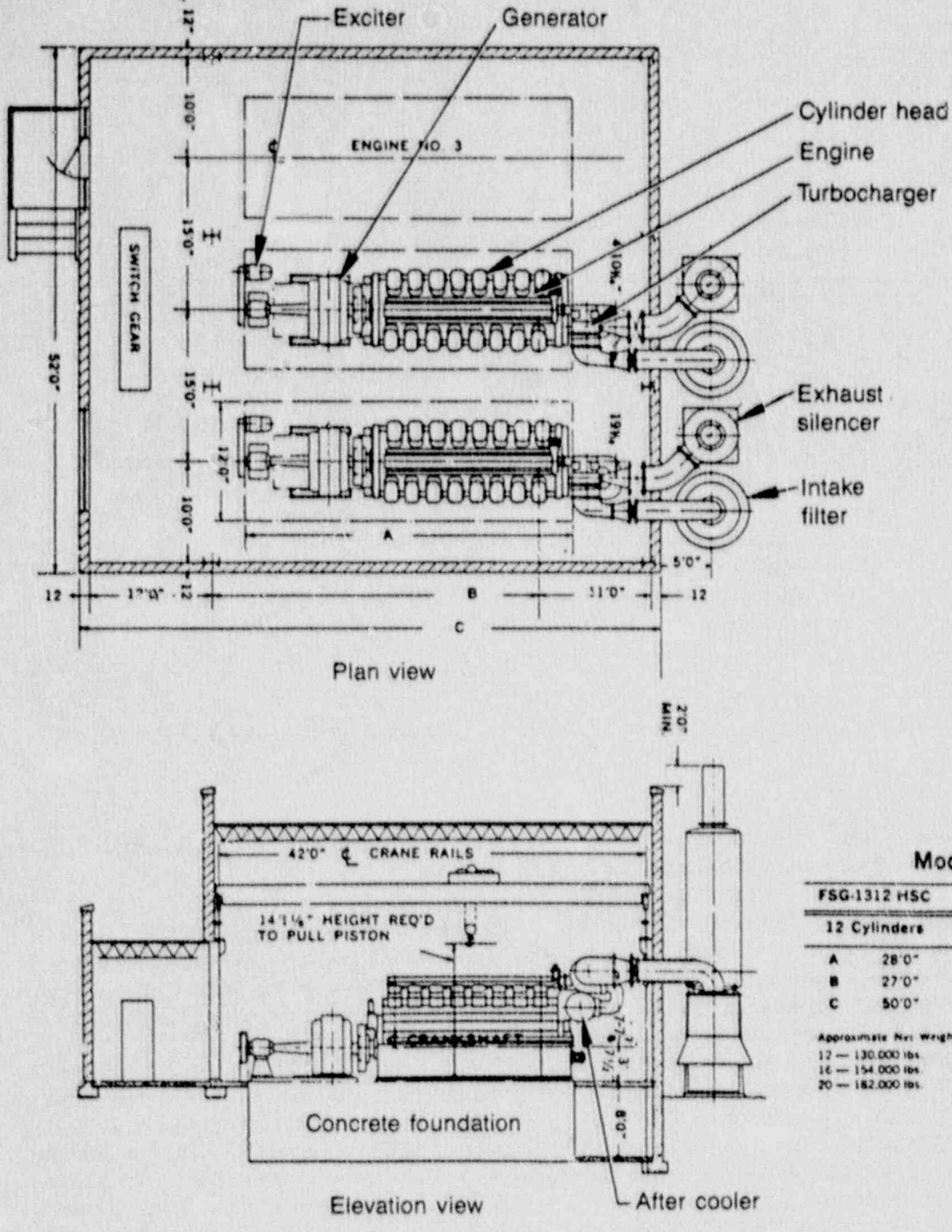


Figure 14.2. Typical skid-mounted engine-generator package (Electromotive Drum, General Motors).

though one frequently used design is an in-line arrangement of dual, opposed pistons in common cylinders, driving interconnected upper and lower crankshafts. Both two-cycle and four-cycle designs (that is, either two strokes per combustion cycle or four) are employed. For a four-cycle engine, the upward stroke following the downward power stroke pushes all remaining combustion gases out the exhaust valve(s), thus scavenging the cylinder. The next downward stroke pulls fresh combustion air into the cylinder through the intake valve(s); this is followed by the upward compression stroke, oil injection and ignition, and the next power stroke. In the case of the two-cycle engines, combustion gases are vented near the end of the downward power stroke, either through an exhaust valve in the head or through ports in the side of the cylinder. When that same downward stroke is about bottom, intake ports are uncovered by the piston, allowing pressurized combustion air to enter. The two-cycle engine design is such as to scavenge most of the remaining combustion products out the exhaust ports or valve. The arrangement of ports in the one two-cycle design sweeps scavenging air through the cylinder in a loop, so-called loop scavenging. The other two-cycle design, with an exhaust valve, sweeps the flow in a single direction from the lower extremity of the cylinder to the valve at the top, called uni-flow scavenging.

Virtually all EDG engines are supercharged, whereby some external compressor raises the combustion air pressure above atmospheric levels (and that of any combustion gas pressure remaining in the cylinder after scaveging). This allows more fuel to be burned, without any increase in engine piston displacement, thereby increasing the output from the same engine (assuming all components are capable of the higher power duty). Most are supercharged by turbochargers, a rotating turbine/compressor device driven by the exhaust gases. The two-cycle engines also employ mechanically-driven blowers, to provide necessary combustion air and cylinder scavenging for startup and low-load operation.

Typically, such engines are designed and categorized for base-load/continuous duty, intermediate duty, and peaking/standby duty. These rather loosely defined designations relate, in some degree, to their rotative speed, both the peak and average combustion pressures, and to their mechanical durability. The cylinder bore in the larger engines will be as much as 17 in. in diameter and have a piston stroke of up to



Model

	FSG-1312 HSC	FSG-1316 HSC
	12 Cylinders	16 Cylinders
A	28'0"	33'7"
B	27'0"	32'0"
C	50'0"	57'0"

Approximate Net Weight (Engine Only)
12 — 130,000 lbs
16 — 154,000 lbs
20 — 182,000 lbs

9-7584

Figure 14.3. Typical nonnuclear diesel–generator plant layout (Nordberg FSG–13V engines, Cooper Industries, Inc.).

22 in.; for most smaller EDG engines, the cylinder bore will be as little as 8 in. in diameter, have a 10–in. piston stroke, and will operate at higher speeds. Synchronous rotative speeds in most EDG applications are in the range of 450 to 900 rpm, with some of the earlier and smaller units at 1200 rpm. Higher speeds, for the same horsepower, tend to yield faster response in starting and loading and lower initial cost, but with generally shorter life–expectancy, greater maintenance, or both. Peak pressures depend on engine design and operating load, but normally run under 2000 psi. Computed average pressure on the power stroke [also known as the brake mean effective pressure (BMEP)] also reflects the load; for most four–cycle engines in

EDG service, the rated BMEP will be 200 psi or under, whereas for two-cycle units the rated BMEP is likely to be under 130 psi.

All of these design parameters, as well as their other dynamic and structural characteristics, affect the reliability and durability of engines. The engines are a complex assemblage of numerous static and dynamic mechanical and structural parts, and their operative fluid systems (both liquid and gaseous) present a number of opportunities for malfunction, failure or degradation variously resulting from design, manufacture, site conditions, operations, and maintenance.

These engines will have an expected life in central-station service of 30 to 50 years or more, this length being affected by numerous factors, many not related to actual physical condition or continued serviceability. For units in standby service, which is akin to the duty of EDGs (though not usually involving fast starts), useful life can be even longer. Again, external termination is not always a function of physical ability to continue operation.

The main engine systems and components, some of which are primary sites of degradation problems, are as follows:

1. The base, crankcase, and cylinder block—sometimes in single or combined sections, variously of high-grade cast iron or of steel weldments, with various openings, oil passages, etc.; these castings or weldments will sometimes exceed 20 ft in length

2. Cylinders or cylinder liners—most often a type of cast iron—may be up to 1 in. in annular thickness throughout most of their length

3. Cylinder heads—usually nodular iron or cast steel—with associated intake and exhaust valves (one or two each), valve actuating mechanisms, fuel injectors, air starting valves, and various complex cooling water passages, all of which pose a number of degradation or failure possibilities; firing deck thickness will run 0.5 to 1.0 in., varying around valves, seats, injectors, and other paraphernalia

4. Crankshaft, and its extension to drive the generator—usually of forged steel, with internal lubricating oil passages drilled into it; the opposed-piston engines have two shafts, with a connecting vertical driveshaft; shafts will be as much as 15 in. in diameter at main bearings

5. Connecting rods—usually of forged steel—with articulated, side-by-side or blade-and-fork arrangements for V engines, all of them with drilled lubricating oil passages to get oil from the crankshaft to wrist pins and the pistons

6. Pistons, with associated wrist pins (joining the connecting rod to the piston) and several piston rings—usually of cast iron, sometimes of two major pieces, with the crown sometimes of cast steel—cooled and lubricated by oil passages, cavities and spray provisions (oil being received up the holes in the connecting rods)

7. Camshafts, gears, pushrods, and other mechanisms for driving the intake and exhaust valves, fuel oil injector pumps, engine-driven fluid pumps, etc.

8. Numerous bearings—with main and rod bearings usually aluminum or a tri-metal design (usually a steel shell, a bronze bearing layer, and a flash coat of Babbitt)

9. Turbochargers and/or blowers, to supply needed combustion and scavenging air, usually with aftercoolers to cool and densify compressed combustion air

10. Intake air and exhaust gas manifolds, the latter having flexible joints to accommodate expansion differentials

11. Governor, usually mechanical/hydraulic or electric, and associated fuel-control linkages to the fuel oil injector pumps

12. Fuel distribution and injection systems, including engine-driven rotary feed pumps, high-pressure injection pumps (barrel and plunger type), strainers, regulators, and high-pressure fuel oil tubing (for pressures as high as 69 MPa (10 ksi)

13. Lubrication system, including engine-driven main lubricating oil pump (rotary type)

14. Cooling systems, for water jackets and aftercoolers, sometimes including engine-driven centrifugal pumps

15. Starting system, generally consisting of a chain– or gear–driven air distributor directing compressed air to admittance valves in each cylinder head (usually redundant for EDGs)

16. Some form of turning–gear for maintenance purposes, usually engaging teeth on the flywheel

17. Flywheel (sometimes incorporated in the generator)

18. Various instruments and controls, in addition to the governor, including exhaust pyrometers, gauges, etc.

19. Miscellaneous lesser systems, piping, tubing, and wiring.

Illustrative of the complex arrangements of some of these components is the cutaway view of a V engine in Figure 14.4. A cross–section of another widely used V–EDG is shown in Figure 14.5, that of an opposed–piston engine in Figure 14.6. Typical diagrams of the support systems can be found in Reference 2.

Of these many engine components and systems, only a few have been the sites of failures in the many EDG installations. Those of greatest concern, of which more details will be given, are the intake and exhaust, starting, fuel, lubrication and cooling systems, the governor, and the piping.

Intake and Exhaust Systems. The air intake system provides filtered combustion air to the engine. Air filters usually have no moving parts to fail, though untended filter media can become plugged. In all EDGs except the blower–scavenged two–cycle engines, the intake air is compressed by turbochargers, cooled by an aftercooler (an air–to–water heat exchanger mounted on the engine), and drawn into the cylinders. Hot combustion gases—generally at 316 to 593°C (600 to 1100°F)—pass through the exhaust manifold (usually a bundle of exhaust pipes) to the turbocharger turbine, of which a variety of designs are used. From the turbo, gases exhaust through a silencer outside the building. The turbocharger is a relatively high–speed, single–stage turbine driving a single–stage compressor.

Starting System. The most typical EDG installation uses 1– to 1.7–MPa (0.15– to 0.25–ksi) compressed air for starting the engine, by way of either sequentially timed direct injection to the cylinders or by an air–powered turning motor. Two parallel systems are required, to ensure reliability. Direct injection systems require admittance valves in each cylinder head and a central air distributor driven by the engine gears or by the camshaft. Whereas nonnuclear engines are most often started by manual operation of a main block valve and an on–engine lever, EDGs are set up for full remote control, with the ESFAS automatically initiating the process. The air entering the cylinder rapidly accelerates the power train to provide sufficient momentum and dieseling to initiate combustion of the oil. The governor—which for EDGs is programmed for rapid acceleration—brings the engine to synchronous speed. (A further description of the governor operation is presented below.)

Fuel System. Fuel oil is transferred from the main, exterior storage tank to daytanks at the engines, from where it is pumped, usually by engine–driven pumps, through fine–mesh strainers to a header that feeds plunger–type injection pumps. These pumps are actuated by the engine camshaft, pumping fuel at high pressure through tubing to a nozzle in each cylinder head, which atomizes the fuel. The amount of fuel pumped is a function of the design of the plunger and barrel, metered by the governor/linkage/rack system. The pump and injector parts are necessarily machined to close tolerances because of the high pressures involved, with a commensurate risk of binding or scoring.

Lubrication System. Lubricating oil serves both to lubricate and to cool certain components. Oil accumulates in either the base of the engine or in a separate sump tank, from which it is pumped by an engine–driven positive–displacement pump through a filter, next through a temperature control valve to the oil cooler, then to an entrance strainer, and finally to all internal oil piping and passages of the engine. Oil to the main shaft bearings enters through holes in main–bearing saddles and shells, with much of it passing through drilled passages in the journals and crank throws to the connecting rod bearings, then by way of passages in the rods to the piston wrist pins, and out through the rod–tops, where it sprays into the interior cavities of the piston crown and serves to cool the pistons. Other passages carry the oil to certain ring grooves, while oil also sprays or splashes within the crankcase to maintain liner lubrication. Also, there are passages to carry oil to gears, rocker arms, camshafts, the turbocharger, etc.

Engines are also customarily provided with a before–and–after (B&A) pump, which, upon command, will circulate some amount of oil (usually at least one–third normal flow) to all necessary points before engine operation and then again upon shutdown, primarily to cool pistons and other hot

Colt-Pielstick PC4.2V Diesel Engines

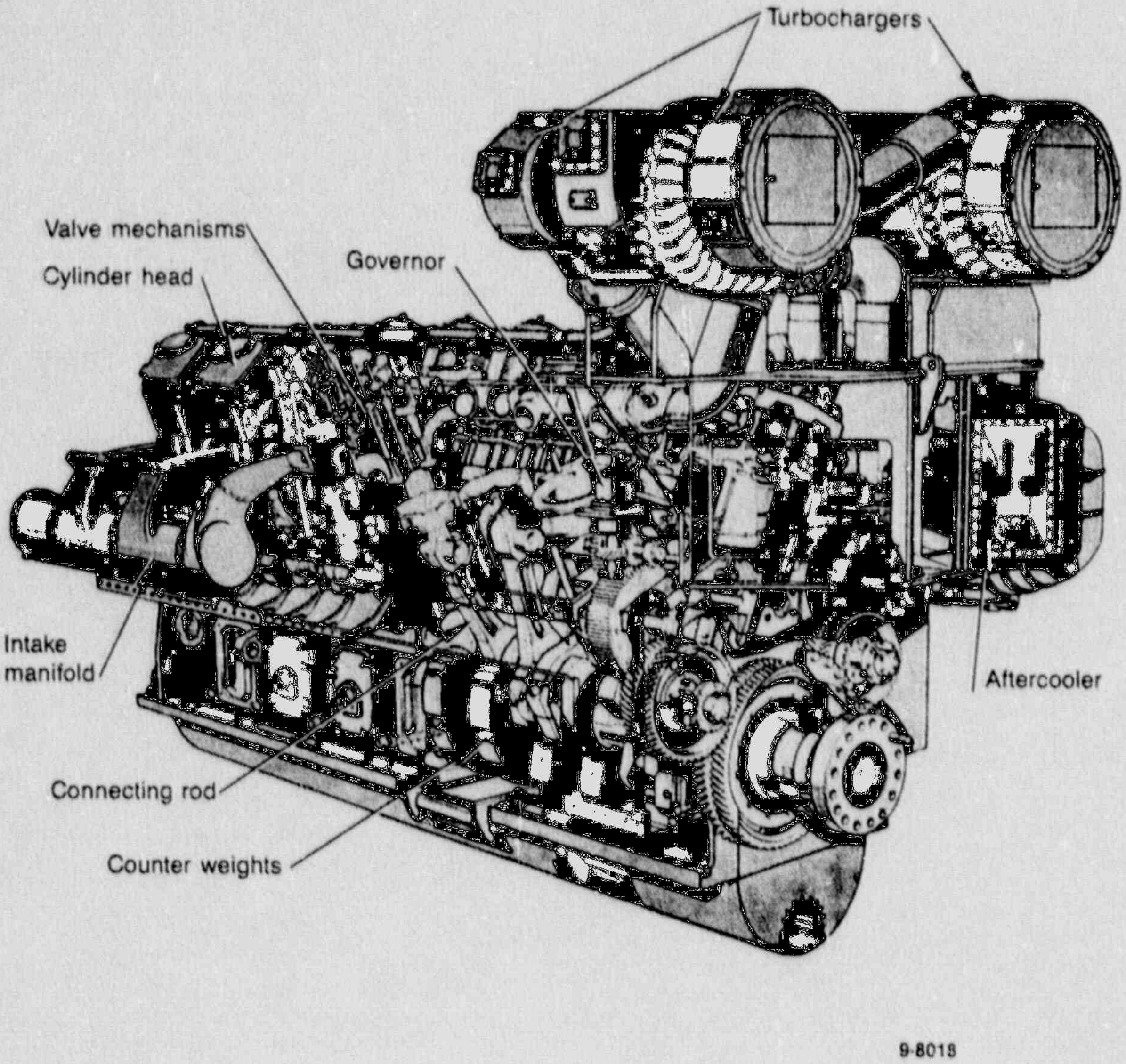


Figure 14.4. Typical V engine (Colt–Pielstick PC4.2V, Colt Industries, Fairbanks–Morse Division).

components. A keep–warm system often is used, continuously circulating a small amount of oil through a heater to most of the engine bearings; sometimes this system includes a fine filter to continually polish the oil during standby.

Cooling System. The primary cooling system is the engine jacket water, usually circulated by an engine–driven centrifugal pump, through some form of cooler and a temperature control valve, then to the lubricating oil cooler, on to the engine jackets, heads, turbocharger and elsewhere, from which it returns to the pump, usually by way of some means for venting accumulated gases, all as a closed–loop system. The ultimate heat sink may be the atmosphere, by way of a radiator or a cooling tower, usually using a separate cooling water circuit. Or, some other sink might be used, such as a lake, stream, or ocean.

Jacket water may also be used to cool the supercharged combustion air, by way of the aftercooler, or, depending on engine design, a separate cooling system

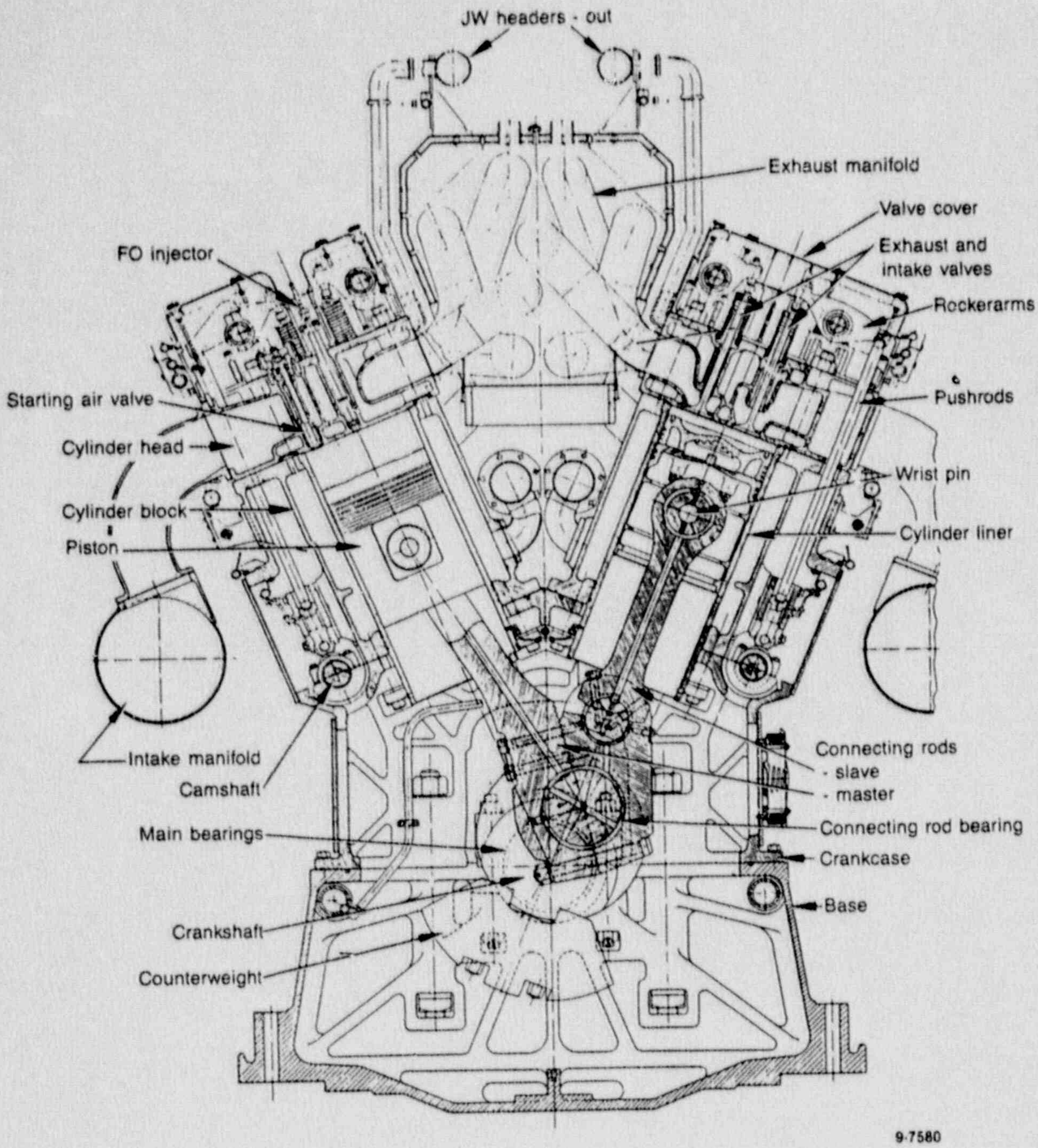


Figure 14.5. Typical V engine (TDI–DSRV–4, Enterprise Engine Division, Transamerican Delaval, Inc.).

may be used. There usually is also some means to heat the jacket water for keep–warm purposes, circulated by a partial–flow pump. Also, the jacket water is chemically treated to prevent scale formation.

Water around the cylinder liners usually is sealed from the crankcase by O–rings at the lower end of the liners. Other joints have comparable O–rings or gaskets, and hoses are used in various locations.

Governor. The engine governor usually is a mechanical/hydraulic servomotor device, with an electrical speed-setting control, or it may be a combined electrical and mechanical device. The former, driven

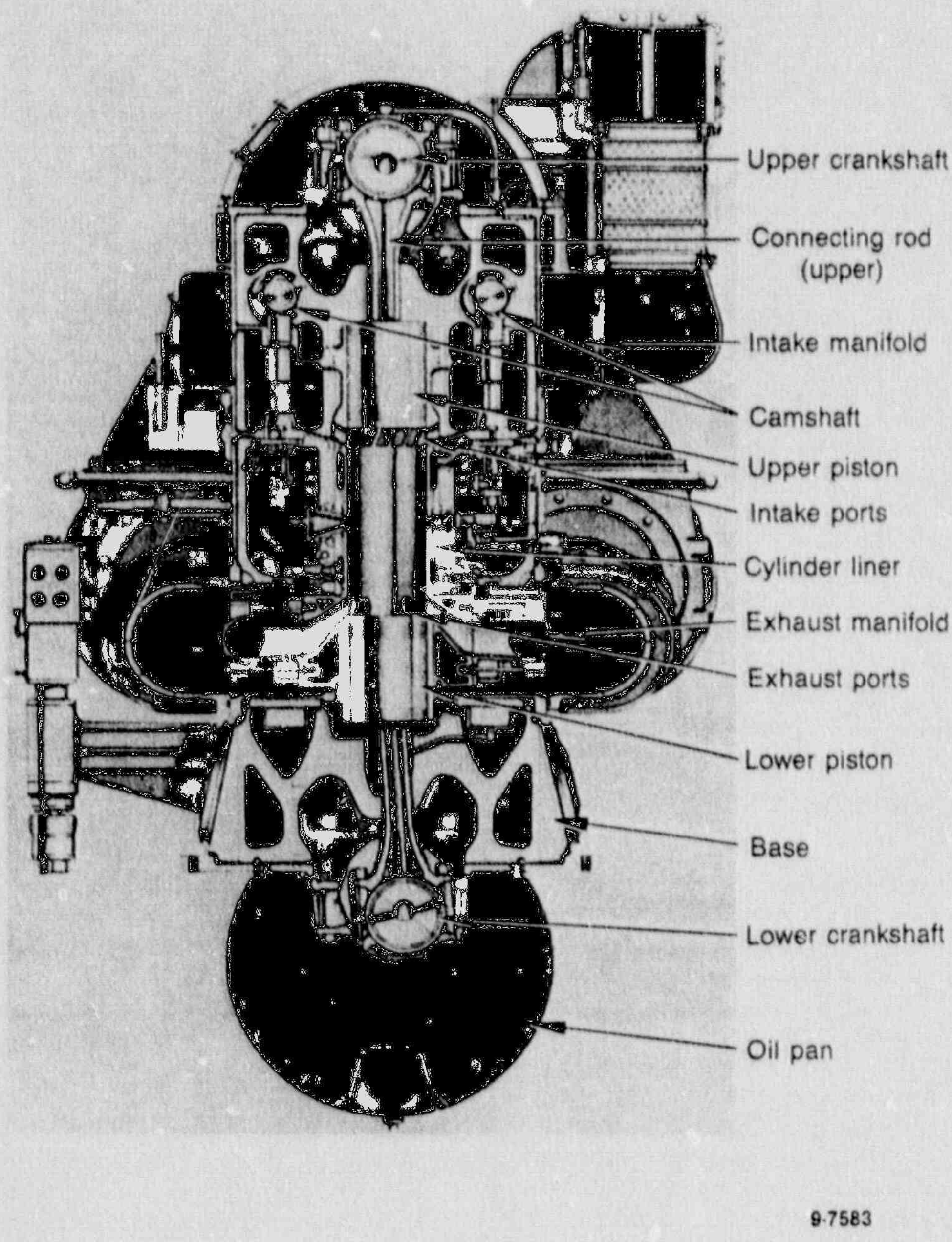


Figure 14.6. Opposed-piston engine (FM-8 1/8, Fairbanks Morse Engine Division, Colt Industries).

off the engine gears, merely senses engine speed changes and adjusts fuel input by means of the linkage and rack system and is able to do so within customary utility-grade frequency specifications, including accommodation to major load step-changes. Such devices have evolved over many years and are quite similar to governors for steam and gas turbines. (Indeed, the vast majority of all prime-mover governors in utility use are the product of a single manufacturer.) They are sophisticated devices, generally rather reliable but susceptible to a variety of adverse conditions that can upset their performance (see Section 14.3.2).

Electro-mechanical governors now are used in some applications. They sense electric frequency (and some even integrate current flow measurements) so as to initiate governor response even before any perceptible speed change.

The output of the governor is to a mechanical linkage that controls the fuel oil injector pump by means of a rack-and-pinion drive to adjust the amount of oil admitted to the fuel oil pump plungers. These linkages are customarily mounted in the open on the engine, where they are subject to dust and damage.

The governor has internal speed, droop, and load-limit adjustments. Whereas speed settings usually are remotely set from the plant control room panelboard by means of a dc control motor, it is also possible to adjust speed locally by hand, as is often necessary for maintenance. The droop setting helps determine load sharing whenever the engine is operated in parallel with other sources on the bus. The load limiter can mechanically block the governor, to place limits on loads under certain conditions.

Piping. A variety of standard steel piping and steel and copper tubing is used on the engine and auxiliaries to connect equipment and to transport water, fuel, lubricating oil, air, and gases. Some fuel oil is under high pressure, and starting air is up to 17 MPa (0.25 ksi), but most other service is below 0.7 MPa (0.1 ksi) operating pressure and under 93°C (200°F) operating temperature [except, of course, the exhaust, which is at up to 593°C (1100°F)]. A variety of flex joints and other fittings are used, many subject to vibration, pulsations, heat, and adverse fluids. Piping connections are variously flanged, welded, or screwed, depending on the service involved and the pipe sizes.

14.1.3 Electrical Systems and Controls

Generator and Exciter. Generators are directly coupled to the engine shaft and are either frame-mounted or on an extension shaft and outboard bearing. They are customarily air-cooled, by rotor-mounted fan blades. Exciters often are belt driven, but may also be of the static variety, as often are the voltage regulators. The generators in many EDG installations lack stator shift, the spatial provision between the generator rotor and the outboard bearing to slide the generator so as to expose stator and rotor coils for inspection and maintenance; this makes them less accessible for inspection and cleaning.

Switchgear. Technically, EDG unit switchgear is outside the bounds of the EDG system (see Figure 14.1), but it is intimately involved in EDG reliability problems. Standard circuit breakers are used and are coordinated with plant-bus design and ESFAS loads.

Station Power. There are numerous EDG-related motors and electrical devices to be served from the station-power bus and transformers, with many interlinks for safe and independent or dual-path operation. Some of these are controlled by the overall plant ESFAS system.

Wiring. There are extensive instrument and control wiring requirements, detectors, actuators, switches, and other devices, besides the main generator leads and power wiring to motors and heaters.

Instruments and Controls. The majority of the instruments and controls (I&C) are electrical/electronic devices, though some may be fluidic (the governor is a combined electrical and mechanical device as discussed above). The I&C components monitor conditions and provide control, alarms, shutdowns, and instrument readouts within the bounds of the EDG system.

Although technically outside the boundary of the EDG system, the ESFAS system of instruments and controls directly affects EDG operation and perceived reliability. Thus, upon occurrence of certain events or conditions—such as loss of offsite power (LOOP) or a loss-of-cooling accident (LOCA)—a signal to the appropriate EDG unit starts it, and it rapidly accelerates to synchronous speed and proper voltage. Under specified conditions, such as loss of normal power to that bus, the EDG is automatically synchronized, its circuit breaker closed, and the emergency loads are then put back on the bus (if they had been lost).

The automatic and manually initiated controls for EDG starting, loading, and stopping are in the control room. Some depend on the availability of ac or dc power. Studies are in process to ensure the ability to start and place the EDGs on line in the event of total nuclear plant power blackout, if need be using local manual means to start the engine and then place it on line to regain plant power. These studies have pinpointed automatic controls in the ESFAS as a site of possible common-mode and common-cause failures.[4] Because such engines are started with compressed air, and air storage for many starts is a design criterion, a properly designed EDG system can be started even without ac power. Station batteries provide dc power for switchgear and possible other needs.

14.1.4 Emergency Diesel Generator Failures and Problems. From the foregoing, it is evident there are numerous possibilities for problems to arise in EDG readiness and operation. That there actually have been so few (see Reference 3) is remarkable and a testimony to the reliability of the many complex systems and components involved and the operational and maintenance care actually given the units.

Various studies have been conducted—principally by the NRC in its NPAR project and by EPRI in regard to the utility industry's perspective—as to the number of EDG failures, the system or components that failed, the root and contributory causes, the corrective measures taken, and the actions that might be taken to avoid or mitigate such problems.

The principal USNRC/NPAR study on EDGs was initiated in 1985 and conducted by DOE's Pacific Northwest Laboratory (operated by Battelle Memorial Institute). The two volumes of their Phase 1 study were issued in 1987,[2,6] followed in 1988 by a Technical Evaluation Report[7] dealing with EDG testing as one aging factor. The basic investigation looked at EDG failures over the years 1965 through 1984, drawing information from (a) licensee event reports (LERs), as reported to the NRC; (b) the Nuclear Plant Reliability Data System (NPRDS), compiled by the Institute for Nuclear Power Operations (INPO); (c) nuclear plant experience (NPE) data accumulated by the S. M. Stoller Corporation and published in 1982; and (d) the Emergency Diesel Generator Component Tracking System (EDGCTS), a data base assembled by the Transamerica Delaval, Inc., diesel engine Owners' Group (TDI/OG) in response to a specific situation of real and alleged problems with this make of engines in EDG service.

The LER reports covered nearly 2400 EDG failure events. From them, over 500 were randomly selected to represent EDG problems. Similarly, reports from the other data bases were randomly selected; then, all were cross-checked to eliminate duplication. This resulted in a base of 1984 failure events for evaluation.

A team of experts in engine-generator design, application, and maintenance then categorized these failure events as to whether they were aging-related, which resulted in a total of 1064, or 54%, deemed related to some form of aging degradation. The events were also allocated to various components and systems of the EDGs (for example, air distributors, injector pumps, exciter, governor) to allow determination of primary degradation sites. Primary and secondary failure causes were identified for each event where possible (such as poor design, adverse site conditions, maintenance error), as were the corrective actions taken (such as adjustment, repair, replacement).

These and other data were then entered into a computer data base from which a variety of outputs could be generated and subsequently analyzed (see Reference 2). It became apparent from the analysis that failures and problems related to almost the entire spectrum of EDG systems and components have occurred. However, there were a few that stood out clearly as primary sites of difficulties, transcending the variety of makes and types of engines and associated equipment. Table 14.1, based on Reference 2, highlights the problem areas; Figure 14.7, taken from Reference 11, provides further information. Of particular note are the governor, on-engine fuel piping and injector pumps, turbocharger, on-engine starting components, and a broad spectrum of other instruments and controls—together, these constitute 45% of all aging-related failure sites.

The experience of the TDI Owners' Group in assessing failures and problems on TDI/Enterprise engines is of relevant interest. The Owners' Group conducted an urgent and technically sophisticated set of studies from 1983 through 1985 following the failure of three crankshafts and a cylinder block in the EDG units at the Shoreham Nuclear Power Station of the Long Island Lighting Company. The failures occurred during pre-operational testing. A number of problems on Enterprise units in other stations were then identified, and all were studied exhaustively by technical experts of the utilities, the manufacturer, and the USNRC. Some proved to be minor in nature; others, such as the shafts at Shoreham and San Onofre, blocks at Shoreham and elsewhere, turbocharger bearings at Comanche Peak and other plants, and high-pressure fuel oil tubing, air admittance valves, and cylinder heads at various plants proved to be significant. Not only did the TDI/OG issue numerous studies, but acting with and for the NRC, PNL issued several Technical Evaluation Reports, culminating in Reference 12. Although not all the failures were aging-related, a number of insights in the area of aging came from these investigations, some of which are noted in Section 14.3.

The problems associated with the TDI/Enterprise engines were of major concern to both the utilities involved and the USNRC and to others concerned with nuclear plant safety and reputation. The TDI problems, the related technical studies, and subsequent efforts at mitigation served to focus attention on the safety importance of EDGs in general. Besides those investigations, several other relevant studies are cited in References 4 through 7, 11, and 13 through 20.

14.2 Stressors

Stressors are any intrinsic, operating, or environmental conditions that can cause component or system degradation or failure. They may act individually or in synergistic or catalytic combination. Intrinsic stressors result from design, materials, manufacturing, application, or installation. Operating stressors occur

Table 14.1 Systems and components contributing most to emergency diesel generator failures

Systems and Components	All Failures[a] (%)		Aging Failures[b] (%)	
Instruments and Controls – System	25		28	
Governor		10		12
Sensors, relays		7		5
Other		8		11
Fuel System	11		13	
Piping on Engine		3		5
Injector		2		3
Other		6		5
Starting System	10		10	
Controls		3		3
Starting air valve		2		3
Starting motors		2		2
Other		3		2
Cooling System	9		10	
Pumps		2		2
Heat exchangers		2		2
Piping		2		2
Other		3		4
Engine Structure	5		7	
Crankcase		1		2
Other		4		5
Intake and Exhaust System	6		6	
Turbocharger		4		4
Other		2		2
Switchgear	10		4	
Relays		5		2
Breakers		3		1
Other		2		1
Other Systems	24		22	

a. Sample population of 1984 failures studied.

b. Sample population of 1064 failures related to aging.

in the course of and are directly caused by EDG operations, both normal and abnormal, including testing and maintenance. Environmental stressors originate in the EDG operating environment. Of the many stressors possible, only those found to have been of significance to EDG reliability are discussed. Specific sites of occurrence are addressed in Section 14.3, Degradation Sites and Mechanisms.

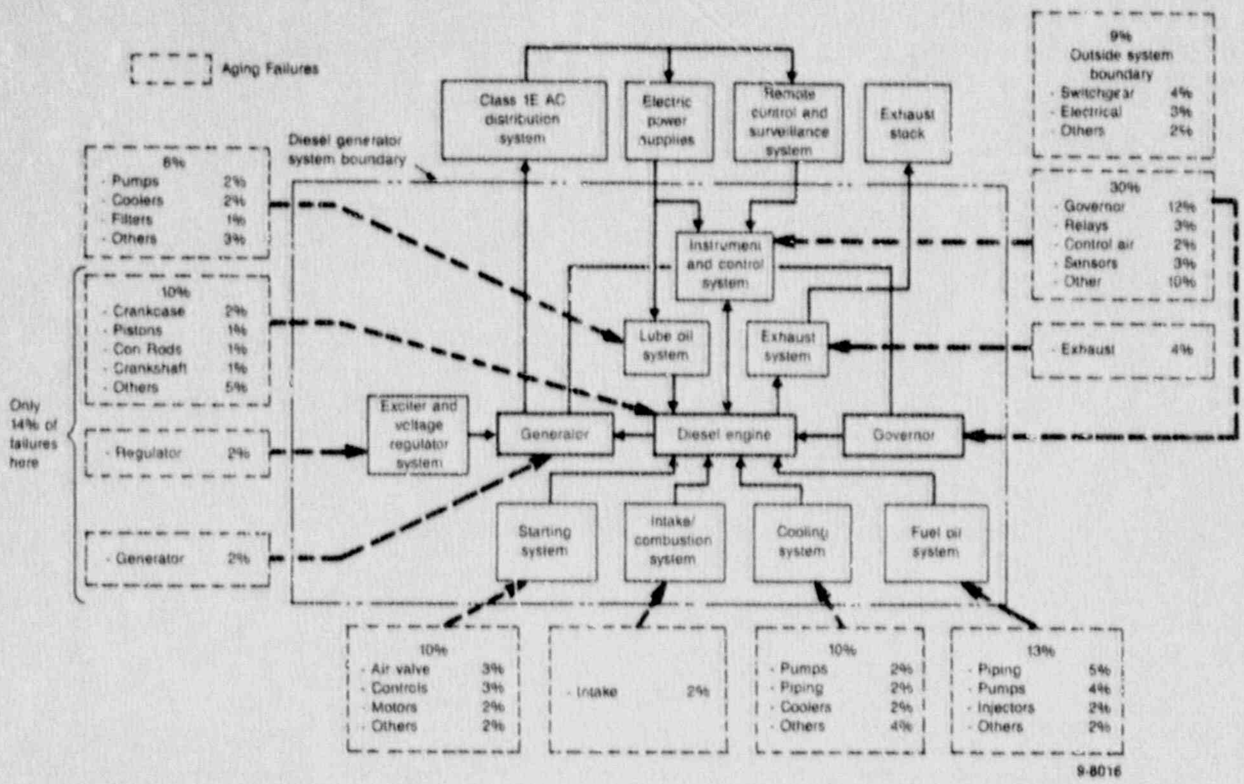


Figure 14.7. Aging failures associated with EDG systems and components (from Reference 11).

14.2.1 Intrinsic Stressors. Engines and generators, and all associated components, auxiliaries, and systems, are individually and collectively designed to accommodate certain maximum conditions over an extended life, given basic care and maintenance. Stresses will exceed component capability, and components will malfunction or fail in some fashion if site or operating conditions exceed these conditions or if the design or manufacture was inappropriate. Consequent failures often occur synergistically with operations or the environment, but they are rooted in the intrinsic character of the component or facility. Relatively few failures should or do occur, but some examples follow (see References 5, 12, and 21).

Crankshafts of three nearly new engines at the Shoreham Nuclear Power Station failed—one with a total break, two with major cracks. Investigation determined the shaft design apparently was inadequate for the loads for which the units were sold. Shafts of two TDI EDGs at San Onofre, also nearly new, were found with fatigue-related surface cracks; various contributory factors of intrinsic nature were involved—one of which related to torsional vibrations at the engine-generators' critical speeds, which were found to be too close to the operating speed and within the speed range for acceleration; the other was the shape of lubricating oil passage entrances. A key component of the crankshaft system of another engine make also has experienced one or more failures, requiring re-design. See Reference 12 and its underlying technical reports for details.

Connecting rods of more than one make have failed from intrinsic design and manufacturing problems, as have cylinder blocks, pistons, cylinder heads, head bolts and studs, bearings, cams, and the like—all apparently because the design, material, or fabrication was not adequate for the ultimate operation of the unit.[12] As one example, the cast iron of one cylinder block had not been correctly heat-treated, resulting in a form of cast iron that could not withstand the stresses that built up between the cylinder openings. The design of one family of piston crowns resulted in stress concentrations and cracking. One design of steel cylinder heads was found to have inconsistent firedeck thickness, leading to thermal stresses, and one family of articulated connecting rods suffered from fatigue-caused bolting failures.

Similarly, various gaskets, O-rings, hoses, and similar synthetic materials have had to be replaced with components made with longer lasting materials. High-pressure fuel oil lines have been found to be sensitive to adverse manufacturing techniques, where a burr on the swaging mandrel or die may cause a sharpedged groove, forming a stress concentrator. Subsequent vibration or pressure pulsations can then lead to fatigue failure.

14.2.2 Operating Stressors. The majority of EDG problems appears to be caused by operational and maintenance stressors. The following problems are of greatest importance:

- Excessive electrical load, sometimes the consequence of later additions to the emergency loads initially planned for an EDG without due consideration of the EDG rating; see References 22 and 23, the latter being an explicit NRC caution to owner–operators to recheck potential emergency loads under all possible operating configurations for a range of design-basis accident conditions

- Sudden applications of electric loads exceeding structural/mechanical design parameters for certain engine components

- Low-level stress cycling, causing fatigue failure, even though the stresses are below the yield strength of the material

- Severe imbalance of loads among cylinders, possibly caused by stuck injector pumps or plugged nozzles

- Prolonged idling or light loads, which because of heat buildup can adversely affect blowers on two-cycle units, as well as plug or foul injector nozzles, deposit oil on turbo blades, etc.

- Rapid starts or rapid loading, in either design-basis events or tests, resulting in fuel input rates and cylinder firing pressures as high as any encountered in normal operations, in order to achieve the specified acceleration and load acquisition; a variety of consequences appear to be related, involving shafts, blocks, turbochargers, wrist-pins, bearings, liners, and heads

- Mechanical vibration, which is particularly damaging to inadequately restrained piping, to controls and instruments, and to fasteners and mounting brackets

- Thermal stresses, caused by (a) temperatures above design parameters, such as might affect exhaust valves and seats, turbocharger inlet vanes and blades, or turbocharger bearings, (b) temperature differentials within a component or between contiguous components, causing excessive stresses as might occur within a piston crown or cylinder head or between a liner and mating cylinder block, and (c) thermal cycling, causing fatigue failure; high temperatures can also affect soft-metal or synthetic gaskets or operating fluids such as governor hydraulic oil, if the design has failed to recognize the problem, or exhaust valves if seat cracks or carbon build-up causes a gap between valve head and seat

- Chemical and electrolytic attack, particularly common ferrous corrosion, which affects a wide variety of components

  - Corrosion of electrical contacts

  - Water scaling on hot surfaces of liners, heads, and turbos

  - Contamination of lubricating oil by leaks of fuel oil or jacket water, acidification from the combustion processes

  - Deterioration of hoses and other organic or synthetic materials

  - Intergranular stress corrosion, as in turbocharger bolts

  - Contamination of fuel oil, from biological action or chemical deterioration from aging (all of which tends to clog fuel oil strainers or to produce varnish on close-tolerance pump parts)

- Cavitation and hydraulic shocks or pulsations, affecting bearings, tubing, and piping

- Erosion, usually in pumps and heat exchangers

- Inadequate lubrication, especially on start-up

- Misalignment of mating components; especially critical are crankshafts, where a variety of conditions can cause them to go out of alignment, such as grout failure; relaxed or broken foundation bolts; broken support ligaments, welds, or bolts in the engine frame; main bearing failures; an excessive temperature rise in the concrete engine foundation; or a constrained thermal expansion of the engine

- Water leaks, which besides contaminating the lubricating oil may enter cylinders and cause water block, damaging the head or piston on a compression stroke in starting

- Maladjustment or drift of control settings

- Maintenance-related stressors, such as improper installation or adjustment, damage to parts, or over- or under-tightening of bolts

- Inadequate monitoring and maintenance activity, which can lead to plugged air and lubricating oil filters and fuel oil strainers or water trapped in the compressed air system.

For details on such events and their consequences, there are numerous citations in References 2, 6, 7, 11 through 15, 20, and 22 through 24.

14.2.3 Environmental Stressors. A number of environmental stressors affect EDG aging and reliability. Some are related to specific sites, but most are more universal.

- Atmospheric pollutants, of which dust is the most prominent, can coat open electrical contacts, cause wear of commutator slip rings and brushes, and clog and stiffen governor/fuel oil linkages; but, owing to air intake filters, such pollutants seldom affect engine internals

- Electrical transients, stray electric currents, corona, and static electricity can variously affect controls, bearings, the generator, and heat exchangers

- Lightning and other incoming electrical disturbances can affect generator insulation and winding integrity

- Humidity and other moisture can condense and collect in the fuel storage tank and may eventually plug some filters; condensate also forms in compressed air systems not adequately dehumidified, and its consequent rust disrupts starting mechanisms

- Oxidation may affect some oils, as well as some electrical insulation and contacts

- Inadequate space in many engine bays is an indirect stressor affecting the quality of surveillance and maintenance.

Radiation does not affect EDGs, as they are located outside the reactor containment.

14.2.4 EDG Operating Experience. Reference 2, the EDG aging study by Pacific Northwest Laboratories (PNL), tabulated from its broad sampling of EDG aging-failure events a profile of causes. The categorization therein differs somewhat from the foregoing summary but covers roughly the same overall scope. Table 14.2 summarizes the PNL tabulation of EDG failures; see the referenced report for detail, including how chronological age affects the failure patterns (also see Section 14.6.2.).

Table 14.2 Causes of diesel generator failures

Failure Cause	All Failures[a] (%)	Aging Failures[b] (%)
Adverse conditions (vibration, etc.)	17	27
Poor manufacturing	22	18
Adverse environment (humidity, dust)	13	17
Human error (maintenance)	13	9
Maladjustment/Misalignment	8	6
Poor design, wrong application, etc.	7	5
Human error (operation)	3	2
Overstress	1	2
Other	5	+
Unknown/not identified	11	14

a. Sample population of 1984 events, 1965–1984.

b. Sample population of 1064 events related to aging.

Adverse operating conditions and environment rank high in Reference 2, together covering 44% of all aging/wear failures. Unexpected were the aging consequences of poor design and manufacturing, totaling 23%; those should be detected and mitigated early in unit life, even on the test floor or in pre-operational testing, but the PNL study shows them remaining significant, even after five years on site. Of further concern are the 11% of failures caused by human error, emphasizing the need for effective ongoing training experience.

In a subsequent workshop, reflecting subjective input, industry representatives were asked to rank contributory causes. They ranked the top five as adverse environment, poor maintenance, overstress in fast starts and loading, poor design and manufacturing, and poor operation. These together constituted 67% of their responses; adverse conditions, like shock and vibration, which were statistically the most common stressor, per Table 14.2, ranked only sixth.[6]

14.2.5 Mitigation Efforts. Some intrinsic stressors have been or will be mitigated by discovery: (a) by careful attention during specification, selection, design and drawing review, documentation, testing, etc. (see Reference 6); (b) by events like fuel oil line or ESFAS control failures, which occur in EDG break-in operation; and (c) by careful interface with the equipment vendors. Some mitigation may result from certain operating limitations, such as avoiding engine-critical speeds, rather than correction per se. Changes in procedures, enhanced surveillance, preventive maintenance, component replacement, keep-warm systems, and the like can also mitigate various operating and environmental stressors (see Section 14.5). Careful training of operators and maintenance personnel and adequate hands-on experience in regular engine operation will result in beneficial mitigation; this was stressed by participants in the workshop discussed in Reference 6.

The matter of fast starts and fast loading is of significant importance. Studies continue on this subject along two lines: (a) to change design-basis-event starting and loading requirements to allow maximum possible time to ramp-up the engine and subsequently load it and (b) to eliminate or greatly reduce the extent of the fast-start testing. In fact, there is increasing evidence that this possibly is the paramount stressor affecting EDG reliability and aging. Further details are provided in Section 14.5.

14.3 Degradation Sites and Mechanisms

Section 14.2, Stressors, and Table 14.1 have indicated the significant degradation sites. Table 14.3, which is based on Reference 2, lists the most troublesome components, ranked by aging failure frequency. The 15 component categories listed account for nearly one-half of the failures in the EDG history surveyed by PNL in the NPAR study.

The list of key failure sites was somewhat different in a study conducted by Mollerus Engineering for EPRI,[15] reporting relays, switches, and instruments and controls, as a group, being the sites of 24% of the failures analyzed, versus a sum of about 10% in Table 14.3. The cooling system accounted for 14%, whereas the fuel system was the culprit in 13% of the cases; these three groups alone summed over 50%. The governor accounted for another 10.3% (versus 10.2% in the PNL study as the greatest single site), whereas the starting system, as a whole, was responsible for 10.3% of all problems (versus a sum of 8.4% in Table 14.3). This EPRI study covered only surveillance-testing failures, in a period of less than five years, and was not limited to aging-related problems. But, despite these caveats, the two studies rather closely parallel in their conclusions as to the important degradation sites.

Conclusions were similar in yet another EPRI study, by Southwest Research Institute.[16] It dealt with failure rates (occurrences per diesel-month) and length of downtime per failure. Table 14.4 presents the results of that analysis, from which it can be seen that though the rankings differ somewhat, the same problem components remain prominent.

14.3.1 Primary Degradation Mechanisms. Study of the considerable data in References 2 and 16 reveals that for the primary degradation sites (see Tables 14.1, 14.3, and 14.4), the primary causes (that is, essentially, the primary stressors) were the topmost ones in Table 14.2. The primary degradation mechanisms appear to be manifestations of fatigue, yielding and fracture, corrosion, wear, and deterioration of working fluids. Other mechanisms can include loss of electrical contact and fire.

Fatigue. High-cycle fatigue is the tendency of material, especially metals, to break under cyclic loading, even at a stress below the material's static yield strength. Ferrous materials in particular have rather clear cyclic-fatigue limits. A large number of cyclic

Table 14.3 EDG components in order of aging failure frequency

Component	Aging Failure[a] (%)
Governor	10.2
Fuel oil piping on engine	4.9
Turbocharger	4.2
Starting air valve	3.4
Fuel oil injector pumps	3.2
Starting controls	2.9
I&C	
Sensors	2.7
Relays	2.4
Control air system	2.4
Engine crankcase	2.4
Cooling pumps	2.4
Cooling piping	2.3
Alarms and shutdowns	2.2
Starting motors	2.1
Alarms and shutdowns	2.2
Fuel oil injectors and nozzles	1.9
Others—83 component categories	50.4

a. Sample population of 1064 events, 1965–1984.

loadings are an inherent aspect of service in the reciprocating and rotational environment of engine-generators; fatigue damage cannot be avoided but only mitigated by proper design, materials, and fabrication and by subsequent proper operation and maintenance. Crankshafts, cylinder and head bolts, connecting rods, fuel oil tubing, and pistons are primary examples of components susceptible to fatigue damage. However, numerous other parts are also subject to vibration or other cyclic loadings and eventually may fail, such as crankcase door bolts, turbocharger mounting bolts, and camshaft drive gears.

Yielding and Fracture. Poor design and manufacturing, or improper maintenance, can make components unexpectedly subject to cyclic fatigue or to outright overstress, beyond the yield strength or even ultimate strength. The TDI crankshaft failures previously cited are examples. Once plastically yielded, a part can become subject to additional stresses, leading to failure of it or a relevant part. Bolted connections are frequent sites of such problems, as elongated bolts can become subject to shear or bending stresses. Cyclic thermal stresses are sometimes a contributing factor in stress failures, such as in uneven expansion of abutting parts or between liners and cylinder blocks during fast loadings.

Corrosion and Chemical Attack. Corrosion has been a key degradation mechanism at several primary sites. It may be caused by adverse chemicals in the operating environment, such as engine exhaust, acidic oils, breakdown of corrosion inhibitors, or oil in contact with the insulation or seal media. More commonly, the problems are caused by moisture in the compressed air supply, resulting in common rust in the air starting components. In some cases, there are combined synergistic effects, such as oxidation of seal materials and thermal stresses. There are also catalytic effects, such as deposits attracting moisture in the exhaust system during standdown periods, leading to corrosion. And, intergranular stress corrosion cracking (IGSCC) has been encountered in internal turbocharger bolting, resulting from temperatures, operating gas conditions, structural loadings, and material characteristics.

Wear. Normal wear is an important aging mechanism[5,25] and can be expected in such places as piston rings and cylinder liners, bearings, exhaust valves and seats, pump impellers, injectors and nozzles, linkage

Table 14.4 Failure ranking[a]

Component Group	Failure Rate[b]	Downtime Rate[c]	Downtime Rank
Instruments and controls (including voltage regulator)	14.3	152	3
Governor	9.9	93	7
Starting system	7.9	105	6
Cooling system	6.5	171	2
Fuel system and injectors	6.4	57	9
Lubrication system	4.9	109	5
Generator	3.3	142	4
Turbocharger	2.3	190	1
Engine — mechanical structural	1.7	80	8

a. Reference 16.

b. Mean failure rate—failures per diesel-month (x0.001)—for example, one I & C failure per EDG every 70 months on the average.

c. Expected downtime—hours per diesel-month (x.0.001) (=failure rate x mean downtime per failure)—for example, an average of 0.152 h per month for I & C failures; or nearly 11 h average downtime for each I & C failure, every 70 months on the average.

pins, circuit breaker contacts, and such—though usually only after extended operations more typical of continuous-duty service. Even in the standby mode of EDG service, wear can occur relatively rapidly because of the frequent fast starts, which generally occur without proper lubrication.[25]

Deterioration of Working Fluids. Working fluids deteriorate for various reasons. Lubricating oil can be contaminated by leaking jacket water or fuel oil (see Reference 26), bearing particles, air entrainment, or excess heat. The special hydraulic oils in the governors are a typical site of difficulty. For example, excessive heat changes the viscosity and can lead to deterioration of the oil, and improper air venting after maintenance causes frothing and inadequate hydraulic function. Water in the lubricating oil breaks the oil film, or forms a foam or sludge, quickly leading to bearing damage.

Other Environmental Degradation Mechanisms. If dust, oxides, or electrical arcing products coat an electrical contact, electrical continuity can be interrupted, leading to failure of a signal or relay function. If a fire develops, such as from an oil spray from a broken fuel oil line, it can quickly lead to severe damage.

14.3.2 Primary Degradation Sites and Mechanisms and Relevant Mitigation Methods.

Governor. As previously noted, these are quite complex machines, having close tolerances on some parts, and all requiring some exactitude in manufacture and maintenance. Torsional vibrations in the engine drive train will reflect into the governor and wear some components, as will excessive engine shaking. A location close to the turbocharger or other hot exhaust components leads to oil degradation. Failure to maintain oil condition and levels or to vent gases will cause trouble.[15] Expert maintenance, though needed infrequently, is a must. Poor manufacturing has frequently been alleged, but sometimes this may be an unjustified accusation.

Appropriate, knowledgeable surveillance and maintenance is the key to good governor performance, once other factors such as vibration and heat have been addressed by restraints or shielding or by relocation or material changes.

Engine Fuel Oil Piping. Fatigue failure caused by inadequately restrained vibration is the most common failure mechanism. Other failures can be caused by manufacturing problems, such as mandrel burrs as the tubing is swaged. As noted above, the high pressures, hydraulic pulsations, and vibrations in the fuel oil feed system can all contribute to ruptures. Mitigation involves appropriate restraint of tubing runs and careful inspection of tubing as it is made and later installed. (For examples, see the background studies of Reference 12.)

Turbocharger. Nearly all EDGs have turbochargers. The two-cycle engines also have mechanically driven blowers, which provide boost during starting, idling, and low-load operation. The turbocharger, which on large engines may rotate up to 20,000 rpm (and higher on smaller engines), operates in a rather adverse environment. Exhaust temperatures are as high as 1100°F. Exhaust gases contain small amounts of slightly erosive ash and carbon particles, and may be somewhat active chemically, owing to the presence of NO_x and SO_x, water vapor, trace amounts of vanadium, etc. Vibration is inherent because of the multi-axis shaking of the reciprocating engine. A variety of forces and moments impinge on the turbocharger from thermally-induced motions of the engine and the exhaust piping. Bearings of some turbochargers are located in high-temperature environments. Varying turbine and compressor loads impose shifting forces on the axial thrust bearings, which often receive inadequate lubrication during fast starts. These bearing problems (and overall turbocharger performance) are aggravated by intake air suction instability, known as surge; surge usually reflects poor turbocharger selection for the site conditions or changes in operating conditions.

Poor manufacturing is sometimes cited as a cause of failure and cannot be dismissed, though that allegation may be of limited validity. Thrust bearings, turbine balance, and blade integrity are areas susceptible either to poor manufacturing or poor maintenance. Lack of adequate pre lubrication is a primary concern in some instances, especially under quick-start scenarios when turbos are already under duress to build air flow and pressure under inadequate exhaust conditions.[13] Some turbocharger or engine designs, however, allow only a brief pre lubrication to avoid oil flooding, which may obviate the benefits of a standard pre-lube system; some installations have been modified to discharge oil from small, elevated dump tanks into the turbo bearings upon startup.

Mitigation is fairly self-evident: detect and minimize vibration, make sure there are no undue piping thrusts, ensure static and dynamic balance, arrange for pre lubrication if possible, and minimize quick starts and loading. Some of the above problems were addressed in the TDI investigations and research.[12]

Starting Valves, Motors, and Controls. Since these engines are started with compressed air, the starting system components are particularly susceptible to environmental problems peculiar to compressed air. Humidity in the compressed air can condense out as the air is cooled by standing in the air receivers or piping. In the absence of dehumidifying facilities, such condensate remains in the system, where it combines with oxygen to attack components. Some parts rust so as to impede operation. Others become blocked with rust particles or sludge. Additionally, pockets of free water accumulate and then are abruptly carried along by the air during the starting process, possibly damaging parts by water hammer.

Some smaller engines are started by air-motor turning gears, which also can be damaged by these problems. However, most engines use valves in each head to introduce 1-1.7 MPa (0.15-0.25 ksi) of compressed air to the cylinders on what amounts to the down power stroke so as to rotate the engine. All the various admittance and control components, including the air distributor, then become subject to this failure mechanism. Furthermore, if an admittance valve sticks slightly open, subsequent high-temperature combustion products can pass through the valve into the air system, causing further damage.

Other problems do occur, according to the PNL documentation, such as wrong piping or poor maintenance, but moisture problems are the primary difficulty.

Mitigation focuses principally on dehumidifying the compressed air; such should be part of proper plant design or should be added later (Reference 15, and others). Proper maintenance, including air piping drain-trap and receiver blowdown, is important.

Fuel Oil Pumps, Injectors, and Nozzles. These are all close-tolerance items and are subject to high-acceleration forces. For this reason, manufacturing lapses usually are evidenced in early operation and corrected. However, poor fuel oil conditions will cause chemical attack, erosion or plugging, or occasional bio-chemical sludges. Maintenance on these finely finished components requires knowledgeable skills so as to avoid minute but incapacitating scars.

Maladjustment may lead to after–dribble from the nozzles, with consequences for pistons and cylinders. Sometimes, oil, staying in the pumps, nozzles, etc., will varnish and coagulate if the engine is not operated frequently, causing pumps to stick or operate poorly.

Proper fuel oil and oil–condition monitoring, coupled with appropriate screens, generally will prevent problems. Cylinder temperatures will indicate misfiring, which is further evidenced by firing pressures. But since there will usually be differing temperature indications among the cylinders, inter–cylinder temperature comparisons are of only marginal help; it is more important to know for each cylinder the pattern of temperatures over time, so as to spot developing troubles. An experienced ear also can often detect firing problems. All of this argues for regular EDG operation as one means of problem avoidance and mitigation.

Instruments and Controls. Many types of controls are involved, differing among functions and types of engines, switchgear, etc. Thus, degradation mechanisms will vary. Despite the variations, probably the greatest problems are environmental (mostly heat, dust, and humidity, especially for electrical components) and operating conditions (vibration, arcing and wrong contact pressure, or impure or condensate–laden air for pneumatic items). Corrosion, arcing products or erosion, and dust coatings are common failure mechanisms, which cause poor electrical contact. Vibration is a major instrumentation and control problem (see Reference 15). Heat will also adversely affect some controls, as will maintenance errors and maladjustment. Furthermore, setpoints on some controls tend to drift, often caused by vibration or failure to secure set–screws.

Vibration and heat problems are best addressed by remounting or relocation. Dust and humidity require sealed enclosures, heaters, or filters. Proper preventive maintenance will avoid many problems, even so simple an activity as cleaning and checking setpoints regularly will help.

Crankcase and Cylinder Blocks. Crankcases and cylinder blocks should not be a problem for long–standing engines. But, along with similar problems in the base, weldments tend to fail in some engines, and castings will occasionally crack, mostly at ligaments, webs, and saddles. In addition to the results of poor design or manufacturing, other causes include unusually high or sharp stresses. Blocks have been affected by differential thermal stresses where liners and blocks mate, believed to be caused by rapid loadings.

Mitigation requires attention to evidences of stressors, such as unusual vibration or looseness between engine base and mounting rails. Evidences of bearing failure, such as bearing particles in the lubricating oil filters may also indicate problems in the engine structure. Some failures can be relieved by welds or metal–locking, but most require replacement (metal–locking is a proprietary means of repairing cracks in cast iron).

Cooling Pumps. The most common problem is failure of shaft seals or packing; these seldom require immediate attention. Of more concern is gradual erosion of impellers and wearing rings, but that usually comes with long operation or considerable grit in the fluid. Depending upon pump design, bad mounting or misalignment will also cause failure.

Erosion is caused not only by contamination but also can be caused by cavitation, which usually reflects poor suction conditions. Vibration can often be overcome by piping isolation, and by use of flexible pipe joints. Maintenance is key to most mitigation; unfortunately, that is difficult with engine–mounted pumps or tightly grouped skid–mounted units.

Cooling Piping. Aging of gaskets and flex joints, and problems associated with vibration, are the most common failure mechanisms. Gaskets may age because of inappropriate material selection or excessive temperatures (for example, by being too close to exhaust components). Flex joints can age from excessive pressure pulsations or vibrations or from piping misalignments exceeding design allowances. Air venting is an occasional problem and can be relieved by changes in layout or by vent traps; failure to address the problem can lead to air accumulation in cylinder heads, with consequent thermal cracking. Where vibration is the cause, more rigid support is necessary, or flexible joints, or both. Because of tight spacing on most auxiliary skids, such solutions may be difficult.

Other. Although the primary degradation sites and associated mechanisms have been discussed above, there are other areas worthy of noting. Occasionally, pistons and liners undergo metal–to–metal contact. The resultant wear usually appears as scuffing of liner or piston or both, a peculiar abrading sometimes akin to chatter marks. Some of this was encountered in the TDI investigations.[12] Lack of lubrication is usually a primary factor, and it is aggravated by the fast–start regimen. Prelubrication will usually mitigate this.

Piston ring wear is normal but is bound to be more pronounced with poorly lubricated fast starts, again arguing for prelubrication and slower starting. Rings also tend to break where they encounter the lips of exhaust ports of two-cycle engines. This tendency increases with hours of operation but is aggravated by adverse starting and loading regimens.

Exhaust valves and their mating seats, which usually are stellited, tend to experience infrequent problems of cracking, with exhaust gas then quickly torching gas paths. Sometimes, carbon particles adhering to the seating surfaces will initiate these problems, as will poor manufacturing and maintenance. Monitoring of the cylinder temperatures for anomalies will usually identify the problem.

Crankshaft bearings are amazingly durable but will fail under adverse conditions of contamination, dry starts, and misalignment. Cavitation, usually caused by air entrainment or initial design deficiencies, will allow oil-film breakdown and metal-to-metal contact. Monitoring of filter media and bearing temperature alarms, if installed, is the main means to catch the problems.

Aging of liner O-rings, no longer found to be a severe problem, will allow jacket water to enter the crankcase and ruin the lubricating oil. Bearings and liners then fail quickly if the leak is severe or if the engine is down for long intervals, as tends to be true of EDGs; such allows considerable water buildup, not relieved by evaporation as when an engine operates regularly. Monitoring the lubricating oil levels in the sump or draining the bottom of the sump periodically will often indicate (before the engine must operate) water buildup in the oil.

Overspeed governors are sometimes troublesome because settings tend to drift; apparently inexplicable shutdowns, especially on startups, are often attributable to this.

Solid-state electronic devices in exciters and voltage regulators fail periodically, especially in earlier models. Heat and vibration tend to be the causes. Pre-failure detection is almost impossible; proper testing and having spare parts on hand are the best ways to manage the problem.

Generator windings may be distorted by severe power surges and occasionally field coils come loose. Mechanical interference and short-circuit usually results. Lightning strikes close-in on the transmission lines may not be relieved by arrestors and might affect any generator in operation. Prudent inspection after any major surge is the best mitigation measure, looking for tracks, broken lashings, or coil distortion.

As mentioned above, bio-fouling of oils in storage for prolonged periods can occur, particularly where water can enter or condense in the tank. The resultant sludge will foul strainers and shut down the engine quickly. Besides regularly draining the tank bottom, it is well to use the oil steadily.

14.3.3 Mitigation Activities. Specific mitigation activities have been noted in several instances above. The PNL study of EDG aging[2] surveyed the data base for corrective actions. Table 14.5 summarizes the information; further details are available in Reference 2. The most common corrective response to actual or incipient failures in EDG installations is to replace with the same component. Sometimes the problem is better resolved by replacing with an improved part; for example, O-rings have improved as new synthetics evolve. But partly because of institutional restrictions in the nuclear industry on use of substitutes, that is only the third most common response. Ordinary maintenance, such as adjustment or realignment, is second to replacement, and actual repair and reuse is fourth.

More indirectly, enhanced training of staff is a fruitful way to mitigate EDG problems. It appears to be almost an emerging technology, as managements recognize the importance of operator and maintenance competency. This was highlighted in the industry workshop to which Reference 6 pertains. It was the opinion of the experts involved in the workshop of Reference 7 that to realize the cost-effective benefits of improved operations, maintenance, and training, changes in policy and attitudes of utility management are in order. Formal schooling arrangements are possible in various ways. Also, informal schooling, such as internships at operating nonnuclear plants, is possible.

One recommendation that evolved[7] was for regular and longer operation of EDGs, so that the first-line staff would become more familiar with the equipment and the fuel would be used regularly. Avoiding a single day's downtime of the entire nuclear plant can pay for a great deal of such on-site EDG operational experience. And though the added run-time may add some imperceptible wear, it is quite likely that overall reliability would actually be enhanced.

The failure of certain TDI EDG units in 1983-84 led to an investigation of all known TDI problems—major and minor, real and alleged. In-depth analyses were conducted by the TDI/OG, the manufacturer, and the NRC (who used the PNL and several technical specialists). This resulted in a variety of targeted mitigation actions, most of them pertinent to TDI units as such and the specific problems involved, but some relevant to the broader perspective of the NPAR investigations

Table 14.5 EDG failure corrective actions

Corrective Action	Actions Reported (%)
Replacement (same component)	52
Maintenance (realign, adjust)	26
Replacement (new, upgraded)	13
Repair (weld, grind, etc.)	5
Enhanced preventive maintenance	2
Redesign and replace	1
Change conditions, environment	± 1
Enhanced training, management, records	± 1
Enhanced surveillance	± 1
Other/unknown/none	± 1

undertaken later by PNL and certainly reflected in their knowledge base.

14.4 Potential Failure Modes

As a total system, the EDG has two main failure modes: (a) failure to start on demand, and (b) failure to operate as required, that is, failure to accept load or to stay in operation under load. Regulatory Guide 1.108[27] defines a successful start–load–run attempt as one that carries at least 50% of load for at least one hour before intentional shutdown; less than that is only a start.

About 43% of failures are in the start mode.[3] As discussed in previous sections of this chapter, numerous factors can be the cause, such as trouble in the controls and instruments, in the governor and control sequencing, in overspeed trips, and in the starting system components. The engine may not turn over; it may not achieve consistent firing; it may not reach speed within the allowed time; it may overspeed and trip; voltage may not reach correct levels; or, once loading is attempted, it may fail to maintain operation for a wide variety of reasons. Although real demands automatically block out some protective circuits, a few remain dominant and will shut the engine down.

Once up, loaded, and in the run mode, the engine may shut down for another long list of reasons, many cited previously. Some are simple and actually almost minor; others are more prominent and troublesome: turbocharger failure, governor inability to maintain control, severe load imbalance between cylinders resulting from fuel oil pump problems, cooling pump failures, or even more catastrophic problems.

Such failures, in either the starting or run modes, are relatively rare; as pointed out in the opening section of this chapter, EDG system failure rates in the start mode were about 0.5% (failures per start attempted), while in the run mode failures ranged from 1 to 2% (failures per run). Considering the numerous systems and components involved and the many potential stressors, this means relatively few problems are encountered in any one mechanism or degradation site. Table 14.4, from Reference 16, provides perspective: at an 0.0023 failure rate (that is, failures per diesel–month), a turbocharger can be expected to fail once in every 435 months (36 years) of its EDG existence, though it will be down an average of 80 to 85 hours each time. The governor may be expected to fail on the average once every 101 months, or 8.4 years, and requires an average 9.4 hours to repair (though serious problems will take considerably longer). The most troublesome system, the instruments and controls, will likely experience failures on an average of every 70 months, with a mean downtime of 10.6 hours. Failure of a major engine component will be even more rare, such as once in every 50 years. Yet taken altogether, the large number of components and systems involved can produce a failure about once every 100 demands (planned and unplanned), which represents about once every 5 to 8 years, and possibly less.

If appropriate preventive and mitigating procedures have been introduced—such as are the objective of the NPAR programs and others—these rates should improve as many problems and stressors are minimized. Some of these will be physical and technical fixes; others (as will be outlined) may be institutional and/or regulatory changes; and some will be centered on operational and maintenance patterns and personnel training and motivation.

Concurrent or common-mode EDG failures, in concert with loss of offsite power (LOOP), have occurred and, though rare, have raised extensive concern. This was expressed in Unresolved Safety Issue USI A-44, concerned with station blackout (see Reference 4).

14.5 Monitoring, Surveillance, Testing, Inspection, and Maintenance

As discussed above, a significant portion of EDG problems and failures can be avoided by pertinent monitoring, surveillance, and testing and effectively mitigated by appropriate inspection and maintenance, regardless of cause or stressor, failure mechanism, or mode. This is the purpose of the rather conservative requirements of such standards as the NRC Regulatory Guides 1.9 and 1.108,[8,27] ASME Sections III and XI, IEEE-387 Sections 5.4 and 5.5,[10] and IEEE-749,[28] as well of course, as the applicable manufacturers' operating and maintenance manuals. Modifications or repairs are accomplished in accordance with IEEE-387, Section 5.4, "Qualification," and Section 5.5, "Design and Application Considerations."[10] (The original design and maintenance of some diesel engine components are performed according to the intent of ASME Sections III and XI.[2]) The regulations and standards are generally considered by investigators of EDG problems to be more prescriptive and stringent than the customary practices of nonnuclear engine-generator operators; yet, in the light of experience, it is doubtful that they are fully accomplishing their purpose. Indeed, in the view of some operators and investigators they may even be self-defeating (see Section 14.6 and References 2, 6, 11, and 15). The outstanding issue identified by participants of the workshop underlying Reference 6 was that "regulatory requirements have an adverse effect on EDG performance."

Although these standards stipulate certain policies, the broad variety of EDGs and support systems have largely obviated any widescale effort to standardize actual procedures. However, some effort has been made toward this objective, as typified by the Design Review/Quality Revalidation Program and various maintenance guidelines promulgated by the TDI/OG (see Reference 12 and the exhaustive reports and manuals by both PNL and the TDI/OG.)

14.5.1 Monitoring and Surveillance. EDGs are comprehensively equipped with instrumentation for monitoring standby and operating parameters and have appropriate alarms (and shutdowns) in case of aberrant conditions. For example, exhaust temperatures, jacket water and lubricating oil pressures and temperatures are instrumented and normally are monitored (but not always recorded). These instruments and alarms usually afford ample opportunity to detect some types of impending or developing problems and to take corrective action, given appropriate operator attendance and attention.

To this end, various experts recommended to PNL[6,7] that greater operator surveillance of units accompany increased EDG operating hours to enhance reliability. PNL has adopted this suggestion and recommends in its reports regular operation of EDGs under load for periods up to 14 hours at a time, so that successive plant shifts would gain regular operational exposure.[7] Data on key unit operating parameters would be recorded at regular intervals, preferably each hour. This reflects input from the participants of the referenced workshop, who ranked the needs for better maintenance practices and skills and more constructive management policies and maintenance procedures as the number four and five issues (behind the first-ranked problems of regulatory requirements). Reference 7 recommends that over 40 operating parameters be recorded during these extended operations, and then trended over time, so as to detect potential or developing problems.

14.5.2 Testing. Regulatory Guide (RG) 1.108[27] specifies a rigorous testing regimen for EDG units. A comprehensive preoperational test of each unit is required, which must be repeated "at least once every 18 months" during its life. The test should demonstrate that the EDG can start, acquire, and sustain full-load for 24 hours (including two hours of overload capability), all in accordance with plant safety requirements. "Full-Load" is considered unit rating, irrespective of the plant emergency load requirements, which are sometimes substantially less than unit nameplate. A formula in RG 1.108 requires 69 successive successful design-basis starts for a one-unit EDG arrangement, with a minimum of 23 successive successful starts each for a plant with three or more units. This formula reflects a statistical analysis which, it is felt, will show the unit(s) is/are proven ready and able to accept load.

Furthermore, a monthly fast–start and load test is also required for each unit, with a minimum of one hour of operation with a full load. Under RG 1.108, the interval between tests is substantially reduced from 31 days if there have been failures to start or maintain load in the previous 100 valid demands or tests, which clearly can span a number of months, even several years, and applies irrespective of the variety of causes or the corrective actions taken.

The purpose of the RG 1.108 monthly tests is to demonstrate statistically that every EDG component and system is operable and reliable at all times. However, a growing body of evidence, direct and inferred, and opinion of experts knowledgeable about engines, etc., contend that these tests are a major contributor to EDG reliability problems and to aging degradation and wear, which is accelerated out of proportion to either the hours run or the number of starts.[6,15,18,19,26] Indeed, surveys conducted by PNL of nonnuclear utility diesel generator installations identified some utilities using engine–generators for frequent peaking service with one or two starts per day. Moreover, these diesel generators experienced few failures and relatively little accelerated aging. These units are generally not rapidly started and loaded.

The fast–starts and loading called for in the NRC testing requirements may not only be unnecessary to prove operability but are probably detrimental to long–term reliability because such a regimen tends to overstress and/or wear some components. A slower starting/loading regimen for both routine testing and emergency starts—if permissible under emergency criteria for a plant—would allow the engine and all other components to lubricate and even to warm–up before taking on a full load.[7,15] Furthermore, it may not be necessary or desirable to require that the full testing load be the unit nameplate load, especially if actual contracted capacity and ESFAS loads are substantially less.[7]

The NRC has recognized some validity to these positions in a Generic Letter issued in 1984.[29] This encouraged nuclear plants to review their station EDG technical specifications and propose less demanding alternatives. However, to date few have chosen to do so. One which has done so has a test schedule as noted in Table 14.6. This reduces the number of tests somewhat but not the stress associated with the fast–starts.

The PNL NPAR studies on EDGs have resulted in several recommendations regarding emergency startups and comparable surveillance testing:[13,14,17]

Table 14.6. Diesel generator test schedule

Number of Failures in Last 20 Valid Tests[a]	Number of Failures in Last 100 Valid Tests[a]	Test Frequency
$\leq 1^b$	≤ 4	At least once per 31 days
≤ 2	≤ 5	At least once per 7 days

a. Criteria for determining number of failures and number of valid tests must be in accordance with Regulatory Position C.2.e of Regulatory Guide 1.108, but determined on a per diesel generator basis. For purposes of this schedule, only valid tests conducted after the completion of the preoperational test requirements of Regulatory Guide 1.108, Revision 1, August 1977, are included in the computation of the "last 20/100 valid tests."

For the purposes of determining the required test frequency, the previous test failure count may be reduced to zero if a complete diesel overhaul to like–new condition is completed, provided that the overhaul, including appropriate post–maintenance operation and testing, is specifically approved by the manufacturer *and* if acceptable reliability has been demonstrated. The reliability criterion is the successful completion of 14 consecutive tests in a single series.

b. The associated test frequency is maintained until seven consecutive failure–free demands have been performed *and* the number of failures in the last 20 valid demands has been reduced to less than or equal to one.

1. The focus of the regulations should be changed from the statistical purview underlying RG 1.108 to a more predictive program of monthly testing, using trends of key operating parameters (monitored from EDG instrumentation)

2. The number of fast-start and loading tests should be reduced, or this type of testing should be eliminated

3. The engine acceleration and loading should be slowed

4. Engines should be operated for a longer period each time tested

5. Readiness of starting and loading controls generally should be checked by diagnostic means, if such can be developed, rather than always in operational simulation. Such a system would check ESFAS signals against a computer program, possibly.

Studies at the DOE's Sandia National Laboratory also reached the conclusion that RG 1.108 testing tended to stress instruments and controls and urged development of diagnostic procedures to check their readiness.[18]

Rationale for Policy Changes. (quoted from Reference 7). "The original basis of the diesel generator testing requirements is discussed in Regulatory Guide 1.108, A., Introduction and B., Discussion. The fast start requirement and reliability goal of 0.99 (at a nominal 50% confidence level) are further defined in the NRC Standard Review Plan and regulated through the plant technical specifications documentation. The Code of Federal Regulation, 10 CFR Part 50 and appendices, further define the basis and requirements for diesel generator testing. Should the number of failures to start or run exceed 1 in 100 tests, the test interval progresses in four steps from 31 days to 3 days for four or more failures, as defined in Regulatory Guide 1.108, Section C.2.d.

"Information from research studies, operating experience, workshops, diesel experts and diesel engine disassembly and examination have shown that the fast-start testing is a major engine stressor, and does little to ensure future engine operability. The engine start time is not given in Regulatory Guide 1.108, which references the technical specifications for each nuclear plant to be used for specifying the diesel start time. These typically are in the order of 10–12 seconds depending on the assumptions used for the specific plant LOCA analysis coupled with loss of offsite power. Fuel cladding temperature calculations which are defined in 10 CFR 50, Appendix K, are part of the plant analysis used for determining the diesel generator start and loading time. These very conservative cladding temperature calculations also were used to develop the 10–12 second start time range. The fast start is a very severe engine stressor when followed with the typical loading sequence time frame of 30 to 45 seconds to achieve full load.

"The possibility for safely increasing the prescribed start time of the diesels is increasing. Some of the reasons for the various regulatory changes being proposed or considered at this time are:

- A major change has already been made to 10 CFR 50, General Design Criterion 4, which accepts leak-before-break analysis and detection methods for the primary large bore piping. Extension to equipment qualification and diesel start time requirements is being considered, but no new criteria have been formulated or released.

- Studies documented by EPRI and others show that the safety function emergency power requirements for the diesel generator system are on the order of 1 to 2 minutes for a LOCA event with a loss of offsite power and 5 minutes, or more, for a loss of offsite power event without a LOCA.

- The calculational methods of 10 CFR 50, Appendix K, have been shown to be overly conservative, based upon the latest information and computer program models. EPRI and other organizations are performing these new calculations.

"In view of the above discussion and referenced material, it seems reasonable to propose that the emergency power mission requirements be reviewed. A more conservative approach for reduction of aging effects and increased reliability is to define the recommended mission as follows:

1. The onsite emergency power is needed in the time frame of about 60 seconds, assuming both loss of offsite power and a large break LOCA event, with a recommended engine start time of about 30 seconds. The exact time permitted would depend upon plant specific analysis, but the conservative position is to permit as much time as can be justified to avoid abnormal aging.

2. The onsite emergency power is needed in the time frame of 2 to 10 minutes, assuming a simple loss of offsite power. Again specific plant analysis would be the basis for this mission loading time. The conservative position in this case is closer to 2 to 3 minutes.

3. For testing purposes, the test mission, or schedule, recommended is to test monthly with a 10 minute ramp up to full power . . . . and semi-annually with the shorter time period typical of the large-LOCA event requirements."

Figure 14.8 is taken from References 13 and 14, papers which themselves are based on the work reported in Reference 7. Present requirements typical of most plants are represented by the solid line labeled "Fast Start - (Current Requirements)." (The horizontal scale of Figure 14.8 approximates a logarithmic time progression.) For an EDG to meet the requirement to attain stable synchronous speed and voltage in 10 to 12 seconds means the speed must be reached initially in less time, with allowance for stabilization to be achieved. To do this, the air-starting system must rapidly roll the engine over and accelerate it, and the fuel pump positioning racks must be thrust to their maximum by the governor—as if the engine were carrying overload. Until combustion begins in the successive cylinders, the turbocharger is ineffectual; once actual exhaust gas begins to flow, the turbo starts to accelerate, to provide the needed combustion air. All of this continues, and the engine accelerates until the target speed—the horizontal line of small dashes—is crossed, at which point the governor immediately returns the fuel racks to the closed position and the engine begins to slow. Understandably, the engine will overspeed somewhat, and then a quick series of repositionings of racks occurs until stability is achieved, a process called hunting. This affects the fuel oil rack positions, the fuel pumps, and the turbocharger all within a matter of a very few seconds. Sometimes, the engine overspeeds enough to trip at the overspeed setting. This immediately compounds the emergency problems, for when the first engine trips out from overspeed protection, the backup engine must start, under the same conditions. Obviously, if this rather stylized curve of engine speed can be less steep, that is, if acceleration can be moderated, the probability of overspeed and other problems can be minimized.

If the load-run mode is to follow immediately, the problems are further compounded. The usual priority load dumped on the newly started engine is a large

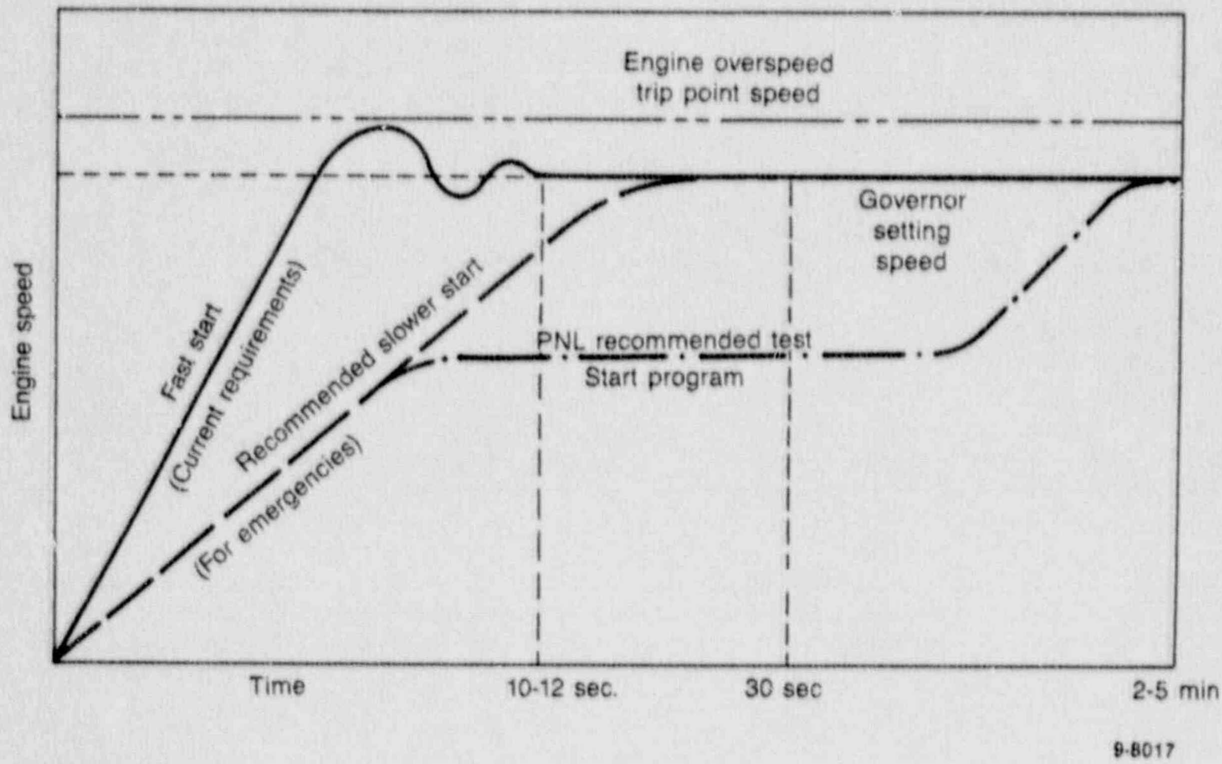


Figure 14.8. Engine speed profile, starting and loading (under present requirements and as recommended; from Reference 11).

pump or series of pumps. In more normative operations, engine generators and their entire fuel and air systems are well able to accept a 25% step–function load change without speed excursions outside utility–grade governing standards. However, this generally pertains to conditions when an engine is operating at 50% load or higher. When an engine is at zero load, it is much less responsive, in large part owing to the need for turbo acceleration, which occurs only as exhaust flow and temperature increases, a function of load and time. Engine fuel racks again go wide open as the engine attempts to take on the load and keep within utility grade frequency response. If the EDG is operating independently rather than in parallel with other resources, there is again the possibility of sufficient instability and hunting to cause overspeed tripout.

As noted, PNL (and others) recommend that this acceleration rate be slowed, approximating the line of long dashes in Figure 14.8, achieving stable synchronous speed in closer to 20 to 30 seconds and loading in 2 to 3 minutes or more (all depending on the redeveloped technical specifications for each plant). It is the conclusion of the PNL investigation[7] that these are legitimate criteria and would not violate safety objectives, and they would avoid or minimize a variety of conditions deleterious to EDG reliability, serviceability, and longevity.

Furthermore, PNL proposes that the starting be still more gradual during periodic testing, as represented loosely by the dot–dash line, approximating the starting patterns of most utility diesel–generator plants.

14.5.3 Inspection and Maintenance. PNL and others have recommended changes to inspection and maintenance policies and procedures, concomitantly with revisions to the rigorous emergency and surveillance testing regulations, so as to detect and prevent incipient problems rather than to rely more on corrective maintenance. Part of this would be a program of monitoring, trending, and evaluating the operating parameters from successive operations. This was deemed a "proactive, condition–monitoring" process able to detect many potential failures prior to actual loss of function, as compared to the largely "reactive" process now in place under Regulatory Guide 1.108.[7]

Details are provided in Reference 7. Simply stated, the theory is that if key parameters do not demonstrate sudden changes or a trend of gradual change from hour to hour within one operating period, or from one run to successive runs, and all are within prescribed standards, the engine and all associated components are operating satisfactorily. This assumes, of course, the electric load or loads are consistent from one time to the next and the engine has stabilized for a period, usually of at least one hour after starting and 15 minutes from one load level to the next. Key parameters include exhaust temperatures from each cylinder, and temperatures before and after the turbo. Others include intake air manifold pressure, lubricating oil and jacket water temperatures, etc. PNL proposes some 40 to 50 parameters (which depend in part on the engine and instrumentation involved.) If, for instance, exhaust temperatures are drifting, valve problems might be indicated, and cylinder pressure readings should be taken; confirmation therefrom might lead to partial disassembly and inspection. Changes in lubricating oil and jacket water pressures would indicate pump problems, while changes in jacket water temperatures or temperature differentials across the engine or the jacket water cooler could indicate low flow, or fouled surfaces, for instance. Inconsistent turbocharger speeds could indicate missing blades or vanes, or fouled surfaces. Excessive lubricating oil consumption would tend to indicate ring problems or liner scoring. A variety of trouble–shooting guidelines would pertain to each make of engine, and even from plant to plant. Since many such parameters will vary with the load on the engine, it is apparent that the loads must be the same from one time to the next.

A somewhat parallel study by EPRI[17] recommends evaluating and categorizing failure modes and establishing maintenance activities commensurate with their probability and consequences, then instituting a feedback program to ensure objectives are met. Little effort would be expended on systems or components with low probabilities of failures. Maintenance on those with modest probabilities would be oriented more toward corrective maintenance after the fact, if and when events occurred. But those with higher failure probabilities would undergo a "proactive" program of "reliability–centered maintenance," with a predictive regimen of monitoring and a preventive maintenance purview by plant management.

A paper by Bergeron emphasizes, similarly, the need to anticipate sites and stressors for high–failure probability and adjust maintenance activities accordingly.[19]

The concensus of all investigators appears to be that a revision in USNRC regulations and industry standards and a shift in perspectives of utility management and operators would allow a program of more constructive monitoring, surveillance, testing, inspection, and maintenance, resulting in an enhanced level of

EDG availability and reliability, and actually result in longer EDG life expectancy.

14.6 Operating Experience

As noted initially, the fundamental EDG components (that is, engines, generators, basic auxiliaries) are almost identical with equipment commonly used in numerous utility engine–generator plants across the nation, as well as in marine, railroad, and other uses. Physical differences are largely in controls for automation and in certain reliability–oriented aspects, such as redundant starting systems. So, it possibly is instructive to generalize the experiences of nonnuclear operations and note some comparisons with nuclear applications.

14.6.1 Nonnuclear Experience. There are some 3,000 similar engine–generating sets in service in the U.S., in over 900 utility–owned plants.[1] Until the 1970s, many such plants generated total system need; indeed, numerous systems were not even interconnected with other utilities, relying solely on their engines. (The fuel crises in 1973 and 1979 changed this pattern.) For economy, many of these engines operate principally on natural gas, using a small pilot charge of oil for ignition—a more complex arrangement, with significantly higher number of fuel–system components and potential problems. Furthermore, such gas-diesel operation is considered more rigorous duty for an engine, principally because of a more rapid combustion pressure rise, including occasional pre–ignition or detonation. Nevertheless, most such systems found their plant operations to be more reliable than purchase of power over transmission lines.

This segment of the utility industry has never maintained a rigorous reporting system, so meaningful statistics on engine–generator reliability, failures, maintenance, and the like are not available for detailed comparison. However, in its various studies, PNL worked closely with experts in the field of engine–generator design, application, and operation, and in some instances, has surveyed the operators (see References 2, 6, 7, 12).

Such engine–generator units customarily operate up to 80,000, even 100,000 hours or more in a normal 30– to 40–year life. Heaviest use usually occurs in the first 5 to 10 years, and 7000 to 8000 hours annual use is not uncommon. Most units will experience 1000 to 2000 starts in their life, possibly more. Thus, durability and reliability are fairly well proven and ought to be translatable to EDG operation.

Units are not kept warm in many of these plants, at least not above room temperature. Starting generally is preceded by several minutes of prelubrication by the before–and–after pump. Starting usually proceeds with a reduced governor setting, raised to near synchronous speed by manual adjustment at the governor, doing so over a 1– to 5–minute period, while reactions and sounds are monitored. Synchronization, voltage control, and bus–closing proceed from the switchboard, after which loads are gradually shifted to the unit; bringing loads up to 50% load may require 3 to 5 minutes or more, and from there to 75 to 100% load another 5 to 15 minutes, depending on circumstances and policy. Conditions are checked regularly, especially exhaust temperatures, and eventually the lubricating oil and jacket water temperatures, all to ensure stability within the accepted norms. Quick–starts are a rarity, except for incipient outages or in blackouts.

Downloading takes several minutes, and disengagement is followed by some idling, then postlubrication for an extended period (if engine design allows; it is inappropriate in some models).

Generally, full–time personnel attend engine operations in these plants (though often only one or two persons on some shifts, depending on plant size). Operators regularly log operating data, and therefore are close to the engines. This mothering of units by operators—casual adjustments, even minor repairs, performed as needed—is believed to beneficially contribute to both effective reliability in operation and detection of impending problems.[2]

Often, the operators are also the maintenance personnel, or assist in such. Few plants engage in a rigorous, planned program of preventive maintenance, but certain preventive inspections are done regularly—such as checking lubricating oil filter pressure drops, observing liner and piston conditions, often with a borescope, and checking shaft alignments, usually once a year. Operation and maintenance diaries or logs (which record problems and action taken) are usually maintained, though most minor items are adjusted or corrected informally.

Major inspections, combined with necessary overhauls, occur about every 20,000 to 30,000 operating hours, or 3 to 5 years, often at the behest of insurors. (Higher–speed, peaking–duty engines will usually require more frequent inspections.) Bearing life often reaches 40,000 hours ring life 20,000 to 60,000 hours. Although major problems or catastrophes are rare, they do occur, for example, a population of cracked heads or pistons, thrown counterweights, even broken shafts.

The aging and wear degradation at most installations has been relatively gradual, though exceptions—most often with new or uprated engine designs—do exist. For a given design, manufacturers tend to raise speeds and average and peak firing pressures as designs evolve with experience and economic impetus; such steps tend to result in a spate of problems until resolved. Over time, most units are eventually relegated to peaking or standby duty; however, retirement or removal usually results from disuse and economic considerations, or the need for space, not because of outright failure.

14.6.2 Nuclear Experience. Many aspects of nuclear EDG experience have been discussed in the sections above. Several considerations stand out, especially from the perspective of nonnuclear diesel experience.

In some ways, EDG operations are substantially less demanding of diesel generating units than are typical nonnuclear utility operations. Paradoxically, however, it appears that EDG units have noticeably greater problems. This is due in part to the fact that nuclear utilities must rigorously record and report EDG problems, even if relatively minor—which raises the perception of more frequent problems. Nevertheless, it also appears to be true to some degree that EDG operations do have more problems, especially considering the few hours of operation or the unit-years in service. EDGs will experience 1500 to 3000 starts and 3000 to 5000 hours of operation over a 25–40 year lifespan—about the same number of starts as a unit in nonnuclear service, but far fewer hours. Average load during such hours will probably be similar to nonnuclear experience, possibly less.

There are some understandable reasons for this situation. One, of possibly major significance, relates to the traditional design-basis starting and loading scenario.[7] This appears to place heightened stress on some components, as discussed in the previous sections of this chapter, with maximum material stresses for short periods, with minimal or no real lubrication in this critical period, with maximum temperature ramps and thermal differentials, and, often, with high electrical step-load imposition. Not only do these tend to impose greater stresses throughout the engine and other systems, even if only momentarily, they are also apt to crowd the physical limits of components that may operate close to their design limits when at full load.

It would seem, then, that any mitigation program would have to address the matter of arbitrarily frequent quick-start engine testing.[15] If, indeed, such starts are a severe stressor, then simulation testing only aggravates and increases problems of aging and unreliability.

Another major contributor, quite evident from the failure surveys,[2] is the complex system of controls for automatic starting and loading, presenting numerous opportunities for failure. Further progress in this one area also is essential if EDG reliability is to be improved markedly.

Some other areas evidencing problems actually should not be having them. Vibration, water in the air systems, heat, dust, and the like should not pose greater duress for EDGs than for units in more prolonged operation in municipal plants. Mitigation should be fairly simple; however, successful mitigation will depend in part on the overall quality of the training and experience of the EDG operators and maintenance personnel.[6]

Some studies[2,13] have shown that EDG aging failures tend to increase moderately with time, though the underlying data base is somewhat too limited to justify significant inferences. Indeed, other studies have concluded a possible inverse relationships[15] or virtually no change in failure rates with age.[18] Thus, it appears there is little innate overall deterioration of the EDGs or their primary systems in emergency-duty EDG service except possibly that related to frequent fast-start testing and the effects of extensive, complex control systems.

14.7 Summary, Conclusions, and Recommendations

Emergency diesel generating units are a crucial component in every nuclear plant's emergency safety system. As such, they must operate reliably under adverse emergency conditions. But as complex systems, EDGs are inherently subjected to a number of operational and environmental stressors, which are aggravated by the emergency and testing demands placed upon them. Some of those test demands accelerate wear and aging and may decrease life expectancy.

The mitigation of a few key stressors and careful maintenance of a few primary degradation sites would greatly enhance EDG reliability and longevity, and consequently reduce risks in nuclear plant operations. Attention needs to be given to the stressors of fast starts and loadings, vibration, fatigue, heat, and corrosion, particularly corrosion in the air-start components. Likewise, surveillance and maintenance attention must be focussed on governors, turbochargers, on-engine fuel oil components, the air-start system (from compressor to admittance valves), and to the myriad controls and instruments—especially those involved in the ESFAS starting and loading systems and procedures.

Tables 14.7 and 14.8 summarize the information on the principal degradation processes developed in the various NPAR and other research studies, and examined in this chapter. Table 14.7 presents information on processes related to the structural/mechanical systems; Table 14.8 presents those related to electrical systems, instruments, and controls.

The authors have developed the following primary conclusions and recommendations, identified from the foregoing compendium of EDG aging studies and papers, and from the various references.

14.7.1 Conclusions

1. Although EDGs operate relatively few hours per year, and generally they start no more often in thei lives (on average) than comparable engine-generators in nonnuclear service, they give evidence of more problems and functional failures than do their cousins in other utility service.

2. Some of this evidence is due to the rigid recording and reporting requirements of the nuclear industry; that is, even minor problems are reported as failures, which in other service would go largely unnoticed an' accorded little import.

3. Nonetheless, a significant portion of EDG failures are real and threaten their critical mission as the last line of defense in event of power outages in the nuclear generating plants.

4. There are myriad systems and components that can fail, because these EDG units are complex and amount to complete generating plants in themselves. EDG units/systems as a whole experience failures to start and/or run of about one to five percent of the attempts—both real demands and operational tests.

5. Although failures of most individual items are quite infrequent, there are some key components that exhibit greater inclination for problems or failures:

   a. Governors

   b. Fuel oil injector pumps, nozzles, and high-pressure piping

   c. Turbochargers

   d. Starting air admittance valves, distributors, and piping

   e. Instruments and controls, particularly those controlling starting and loading.

6. Of all the failures, some 50 to 60% are attributable to aging and wear; others are attributable to malfunctions obviously related to other causative factors.

7. There are numerous stressors affecting EDG component viability; key among them are

   a. Adverse operating conditions—vibration, excessive loads, fatigue, corrosion, and poor lubrication

   b. Poor quality starting air

   c. Poor design and manufacturing quality

   d. Adverse environmental conditions—dust, humidity, heat

   e. Poor maintenance and operation

   f. Deterioration of working fluids.

8. The regimen of fast-starting/fast-loading imposes several burdens on EDGs not normally encountered in nonnuclear utility service and appears to both demarc and explain why EDG service results in more failures, per hour of use or number of starts than does other service.

9. Other adverse conditions of EDG service include

   a. The extent and complexity of the EDG control systems

   b. Limited hands-on monitoring and mothering of EDG units in operation, a freedom available to and inherently used at nonnuclear plants

Table 14.7. Summary of major degradation processes: EDGs – structural/mechanical systems

Rank[a] (System)	System[a]	Degradation Site[b]	Key Stressors	Degradation Mechanisms	Failure Modes
1.	Fuel system	Piping on engine[c]	Vibration; internal pressure; pressure pulsations	Metal fatigue; overstress – Sometimes caused by poor manufacturing or maintenance errors	Start or run modes. Fracture, leakage (sometimes resulting in fire)
		FO injection pumps	Adverse internal conditions	Binding of plunger (the results of physical scoring or varnishing) – Caused by poor manufacturing, maintenance errors, deterioration of oil (chemical change, bio-fouling, particles in oil)	Start or run modes. Failure to deliver oil or inadequate pressure and quantity – Reduces engine capacity and unbalances loads among cylinders
		FO injectors and nozzles	Adverse internal conditions	Binding of parts; plugging of nozzle holes – Same causes as above	Start or run modes. Same consequences as above
		FO supply pumps	Overstress; metal/metal contact	Metal fatigue; overstress; wear – Usually caused by misalignment and maintenance errors	Run mode. Fracture of drive shaft or coupling; loss of pressure, reduction in flow
		Strainers and filters	Contaminants in FO	Plugging of media, (particles in oil, biofouling, deterioration); – Usually caused by poor maintenance	Run mode (usually). Loss of oil flow, stopping engine
2.	Starting system	Starting air valve	Contaminants in compressed air (water, dirt)	Corrosion; plugging (by corrosion products, dirt); binding – Partially caused by poor maintenance, poor design of plant	Start mode. Failure to start. May also lead to combustion gases in air system (see text)

Table 14.7. (continued)

Rank[a] (System)	System[a]	Degradation Site[b]	Key Stressors	Degradation Mechanisms	Failure Modes
		Actuators/controls	Moisture in air; water hammer	Corrosion; plugging binding; water hammer (see text); – Partially caused by poor design and manufacturing and maintenance	Start mode. Failure to start; air leaks; fracture on damage from water hammer
		Starting motors	Contaminants in compressed air (water, dirt)	Corrosion; binding – Partially caused by poor design and maintenance	Start mode. Failure to start
3.	Cooling system	Pumps	Cavitation; metal/metal contact; contaminants; poor water chemistry	Erosion (the result of cavitation and particles); wear; corrosion – Partially caused by misalignment and poor maintenance, and to poor design (low NPSH)	Run mode. Loss of pressure and flow (erosion and corrosion of impeller and wear rings); leakage (at seals)
		Piping	Vibration; heat (if exposed piping); poor water chemistry; cavitation; unvented air	Damage to fittings, valves and controls; deterioration of gaskets, hoses, flex joints – Partially caused by poor design, maintenance	Run mode. Leakage; poor pump operation, air may cause hot spots in cylinder heads
		Heat exchangers	Cavitation; contaminants (dirt); stray electric currents/galvanic corrosion	Erosion of baffles, tubes; corrosion of tubes and tube sheets – Partially caused by poor design and manufacturing	Run mode. Leakage (usually internally); loss of capacity
		Radiator	Inadequate air flow; freezing; chemical attack	Plugging of fins; overstress tubes; corrosion	Run mode. Loss of capacity; leakage

Table 14.7. (continued)

Rank[a] (System)	System[a]	Degradation Site[b]	Key Stressors	Degradation Mechanisms	Failure Modes
4.	Engine structure	Crankcase and cylinder block	Dynamic stress; thermal stress	Dynamic and thermal fatigue; uneven expansion of abutting parts – Partially cuased by fast loading and poor manufacturing	Run mode. Cracked block/ crankcase; water leakage (usually into LO; ruined bearings and shaft)
		Liners and seals	Metal/metal contact with pistons; heat; chemical attack	Wear/scuffing; hotspots (caused by water scale); deterioration of seals – Partially caused by fast loading and lack of LO	Run mode. Piston seizure; crankcase explosion; leakage to LO; degradation of liner (heat)
		Main bearings	Loss of LO film; cavitation; heat; overstress	Wear; erosion/cavitation; wiping; fatigue cracking – Partly caused by fast starts; poor LO pressure; misalignment; poor maintenance	Run mode. Bearing fracture; loss of bearing capability; damage to crankshaft
		Cylinder heads	Overstress; heat	Overstress; dynamic and thermal fatigue; hot spots – Partly caused by poor design and manufacturing; fast starts	Run mode. Fracture/cracking; water leaks (usually into cylinder, leading to other problems)
		Bolting (all)	Vibration; overstress; dynamic stress	Fatigue; overstress – Partially caused by poor design	Run mode. Elongation; fracture (with other consequences)
5.	Intake and exhaust system	Turbocharger[c]	Vibration; heat; corrosion; overstress; surge	Bearing failure; loss of vanes and blades; fatigue fracture, IGSCC – Partly caused by fast starts and loading, poor LO flow, poor design and manufacturing	Run mode. Bearing loss and rotor seizure; loss of capacity; water leakage; fracture

Table 14.7. (continued)

Rank[a] (System)	System[a]	Degradation Site[b]	Key Stressors	Degradation Mechanisms	Failure Modes
6.	Lubrication system	Pumps	Overstress; cavitation; pressure pulses	Overstress; fatigue; erosion	Run mode. Fracture; loss of capacity
		Heat exchangers	Cavitation; electric currents/galvanic corrosion	Erosion and corrosion of tubes and baffles, poor manufacturing	Run mode. Leakage (internal)
		Lube oil	Contamination; heat	Sludge and foam; chemical deterioration – Usually caused by jacketwater leaks	Run mode. Viscosity changes; sludge; loss of oil film
		Piping	Vibration; pulsations	Damage to fittings and devices; fatigue – Usually caused by poor design	Run mode. Fracture (fittings, devices, flex joints, hangers)
		Filters	Overstress; contamination	Plugging; fatigue (from pressure pulses)	Run mode. Loss of LO flow; fracture
7.	Drive train	Pistons and rings	Dynamic stress; thermal stress; metal/metal contact with liners	Overstress; fatigue; wear/scuffing – Partly caused by fast starts, poor design and manufacturing	Start and run modes. Broken rings; piston seizure; scuffing; fracture; burned piston crown; explosion
		Connecting rods	Overstress; dynamic stress	Stress failure; fatigue (especially in bolting areas) – Partly caused by poor design and fast starts and loading	Run mode. Fracture; piston seizure; crankcase explosion

Table 14.7. (continued)

Rank[a] (System)	System[a]	Degradation Site[b]	Key Stressors	Degradation Mechanisms	Failure Modes
		Crankshaft	Dynamic stress; torsional vibrations; bad bearings	Overstress; unbalanced loads; fatigue – Partly caused by poor design, misalignment, bearing failure, operation at critical speeds	Run mode. Fracture; crankcase explosion

NOTES:
FO = fuel oil
LO = lubricating oil

a. From Table 14.1 and 14.2 and Reference 2.

b. From Tables 14.3 and 14.4

c. Piping on engine and turbocharger rank as first and second highest individual degradation sites, respectively.

Table 14.8. Summary of major degradation processes: EDGs – electrical systems: instruments and controls

Rank[a] (System)	System[a]	Degradation Site[b]	Key Stressors	Degradation Mechanisms	Failure Modes (mode in which occurring)
1.	Instruments and controls	Governor	Vibration; torsional vibration; heat; oil contamination	Maladjustment; wear; fatigue; Viscosity change; oil deterioration – Partly caused by misapplication, poor maintenance, fast starts	Loss of effective governing control; drift; fracture of components; (start and run modes)
		Sensors and relays	Vibration; dust, humidity, chemical attack; heat	Maladjustment and drift; loss of electrical contact; corrosion; overheating; arcing dust; erosion – Partly caused by misapplication	Interruption of function (start and run modes)
		Control air system	Vibration; moisture, dust	Maladjustment, plugging	Interruption of function (start and run modes)
		Alarms and shutdowns	Vibration; moisture	Maladjustment; fatigue; corrosion	Interruption of function (start and run modes)
2.	Generator components	Voltage regulator	Heat; vibration	Loss of function; broken contacts; – Partly caused by poor manufacturing, maintenance	Interruption of function (start and run modes)
		Generator	Torsional vibrations; overstress; electrical grounding and voltage excursions; dust	Fatigue; overstress; insulation failure	Fracture; loss of distortion of coils, grounding [run mode (usually)
		Exciter	Dust; humidity; vibration (static types)	Wear; arcing	Loss of function (run mode)

Table 14.8. (continued)

Rank[a] (System)	System[a]	Degradation Site[b]	Key Stressors	Degradation Mechanisms	Failure Modes
3.	Switchgear	Relays	Dust; humidity	Corrosion; loss of electrical contact	Interruption of function [run mode (usually)]
		Circuit breakers	Arcing (usually on break); humidity	Corrosion; maladjustment	Interruption of function; explosion/fire (start/stop mode)

a. From Tables 14.1 and 14.2 and Reference 2.

b. From Tables 14.3 and 14.4.

c. Lack of ongoing operational experience by EDG operators and maintenance personnel; such experience gives most nonnuclear operators greater awareness of operational conditions and incipient or developing problems.

10. EDG unreliability and failures will not be significantly reduced until the key factors listed in 7, 8, and 9 above are effectively addressed and mitigated. However, it is the conclusion of most investigators that, to a great extent, such can be achieved by judicious changes in operational and maintenance regulations and practices.

11. One general thrust relates to development and application of appropriate maintenance programs geared toward anticipating and mitigating known key stressors and their consequences at recognized degradation sites. This involves monitoring and trending operating parameters and the performance of reliability–centered preventive maintenance before events occur.

12. Maintenance programs also must involve heightened and ongoing training for operational and maintenance personnel, and greater management appreciation of the need—and benefits—of such programs.

13. Possibly the greatest gain will come, however, from a change in the NRC's fast–start/fast–load requirements.

    a. A shift of rather minor proportions in acceleration to synchronous speed should reduce appreciably the problems engendered by physical stresses and inadequate prelubrication.

    b. Elimination of, or a significant reduction in, fast–start testing, shifting instead to a program of more measured starting and extended operation, accompanied by monitoring, trending, and evaluation of key operating parameters, will eliminate many stressors and actually be more revealing of incipient problems.

    c. Additional analysis and evaluation would likely show that very fast starting and loading of EDGs is not required for most (or maybe all) loss–of–power–and–coolant accidents.

14.7.2 Recommendations

1. Applicable regulations, standards, and plant safety specifications should be altered to minimize fast–start/fast–load EDG requirements.

2. Surveillance and testing concepts, and the whole context of operations, should be modified to enhance awareness of the capability and condition of the unit. An active trend–analysis program should be an intimate part of normative plant operations and surveillance and testing.

3. Maintenance precepts should be reliability–centered; preventive and predictive; proactive rather than reactive; and accompanied by enhanced training of maintenance and operational personnel. Inspection teardown and overhaul should be avoided except as clearly needed.

4. Future research should be focused on troublesome components and dominant failure modes, in cooperation with manufacturers, to identify specific weaknesses and stressors, and to develop pertinent solutions and changes in operations, surveillance, and maintenance so as to anticipate and mitigate effects.

    a. Governors – devising changes in governor internals and/or governor application (mounting, shielding, cooling, etc.) so as to reduce their sensitivity to vibration, torsional vibrations, oil heating, inadequate venting, and other stressors, determined to be deleterious by research and field evaluation

    b. Fuel system components, like injectors, injector pumps, and high–pressure tubing—devising methods to reduce sensitivity to vibrations and pressure pulsations, to adverse oil conditions

    c. Turbochargers – to enable all turbos to accept prelubrication, to cool bearings in better ways, to enhance integrity of blades and vanes

    d. Starting and loading controls – to make these more reliable and less susceptible to dust and moisture and other containments, and to vibrations, in order to improve their longevity under repeated operations.

5. EDG units should be lubricated before startup whenever possible. Equipment on units that cannot presently accommodate prelubrication should be modified.

6. The starting air supply should be kept clean and dry.

7. EDG units should be operated more regularly, for longer periods, to increase operator familiarity with unit operations, to increase monitoring, surveillance, and parameter trending, and to use fuel before it can deteriorate.

8. Provision should be made to ensure ability to manually start each unit in cases of plant blackout.

9. Diagnostic equipment and techniques should be developed to allow testing of pertinent controls and systems related to design-basis event starting programs.

10. The aging of fuel oil and lubricating oil in standby service should be studied, and effective mitigation techniques developed.

11. Owner/operator interface with manufacturers and service departments should be increased; and schooling programs should be instituted and maintained for operators and other relevant personnel.

12. Owner participation in plant design review and equipment validation processes should be enhanced for future EDG facilities.

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15. SUMMARY, CONCLUSIONS, AND RECOMMENDATIONS

Problems associated with time- or cyclic-dependent degradation (aging) such as stress corrosion cracking, radiation embrittlement, fatigue, and other effects have been occurring in U.S. light water reactors as they have matured. These degradation mechanisms have raised questions about the continued safety and viability of some nuclear plants and, in particular, about the integrity of the primary coolant pressure boundary. At the same time, the U.S. electric utilities are motivated to keep our existing plants operating beyond the original design life at as high a capacity factor as possible, because of the increasing demand for electricity and the limited new generating capacity under construction. Therefore, the potential problems of effectively managing aging in older plants has become a major focus of the research sponsored by the USNRC.

A five-step approach is being pursued at the Idaho National Engineering Laboratory to help the USNRC understand, detect, and mitigate the aging of the major light water reactor structures and components: (a) identify and prioritize major components, (b) identify degradation sites, mechanisms, stressors, and potential failure modes, and evaluate current inservice inspection (ISI) methods, (c) assess current and advanced inspection, surveillance, and monitoring methods, (d) evaluate maintenance programs, and (e) develop (or evaluate) residual life assessment procedures. The results of this task will assist the USNRC in formulating a license renewal policy, and will have other regulatory applications as well. Most of the effort for this task on understanding and managing aging is focused on integrating, evaluating, and updating the technical information relevant to aging and license renewal from current or completed NRC and industry research programs. This report provides, in two volumes, a qualitative understanding of the aging degradation mechanisms active in the major LWR components, and it represents completion of the first two steps listed above and partial completion of the third step.

The pressurized water reactor (PWR) and boiling water reactor (BWR) structures and components addressed in this work are listed in Table 15.1, with an indication of which component is discussed in which volume. A summary of the important degradation sites and mechanisms, stressors, potential (and sometimes actual) failure modes, and the current inservice inspection (ISI) methods associated with each component addressed in Volume 2 is presented in this chapter. The review of potential, or in many cases actual degradation sites and mechanisms, identified a number of questions or issues deserving further attention. These conclusions and recommendations are also grouped by component and presented in this chapter.

15.1 Light Water Reactor Coolant Pumps

Table 15.1 summarizes the stressors, degradation sites and mechanisms, and potential failure modes for LWR primary coolant pump bodies, closure studs, shafts, and internal welds. The conclusions and recommendations related to aging degradation of these components are as follows:

1. A model should be developed for estimating the decrease in fracture toughness (thermal embrittlement) of cast stainless steel pump bodies as a function of coolant temperature, time of exposure at temperature, chemical composition, and ferrite content and its spacing in the microstructure.

2. Because the ferrite distributions through statically cast, thick-wall, stainless steel components are not uniform, data for the actual ferrite distributions in pump bodies are needed. Such data will make it possible to more accurately determine the degree of thermal embrittlement.

3. Thermal embrittlement may be such that an existing flaw can reach critical dimensions, leading to failure of the body. Characterization of any flaws would help efforts to evaluate the continued structural integrity of the pump body. Advanced ultrasonic testing methods and radiography methods are needed for this purpose.

4. Standards for allowable flaws in the cast stainless steel base metal are needed. These standards should take into account degradation caused by thermal embrittlement. ASME Section XI, Table IWB-3518-2, provides similar standards for allowable planar flaws in cast stainless steel pump body welds.

5. Annealing of aged pump bodies is not an acceptable method for restoring material toughness. This process causes formation of several other phases in the ferrite, resulting in additional loss of toughness. In addition, annealing could distort the very close tolerances associated with pumps.

Table 15.1. Summary of degradation processes for LWR coolant pumps

Rank	Degradation Sites	Stressors	Degradation Mechanism	Potential Failure Modes	ISI Methods
1	Pump body (casting)[a]	Temperature, system operating transients	Thermal embrittlement, fatigue	Through–wall leakage, unstable ductile tearing	Surface, volumetric, suggest surveillance program
2	Closure studs	Gasket leakage (borated water), mechanical and thermal stresses	Corrosion, wastage	Leakage, breakage	Surface, volumetric, visual (including gaskets)
3	Pump shaft	Thermal stresses (mixing of hot and cold coolants)	High cycle, mechanical and thermal fatigue	Breakage (contained by pump body)	Surface, volumetric
		Mechanical bending stresses (caused by shaft rotations)			
4	Fabrication welds (pump internals)	Mechanical and thermal stresses	Fatigue	Breakage (broken pieces may be carried over into reactor pressure vessel)	None required

a. Wrought carbon steel pump bodies make up a very small percentage of those in the field and have not had a long enough service history to be reflected here.

6. The ferrite content in the pump body welds should be determined. Welds with low levels of ferrite may be susceptible to stress corrosion cracking, especially if the body is not subjected to a heat treatment after welding.

7. Welds in Type F pump bodies and high–stress regions in Types C and E pump bodies may be susceptible to fatigue damage. In addition, the presence of any microfissures in low– ferrite (<3%) welds may adversely affect the fatigue strength of the pump body and should be taken into account in estimates of fatigue damage.

8. The ASME Section XI inservice weld inspection requirements were originally developed for the Type F pump bodies, which have high residual stresses at the welds. However, these requirements may not be practical or meaningful for Types C and E pumps. The high stress intensity regions in Types C and E pumps are likely to include some portion of both the base metal and weld. Surface examination of the high stress intensity regions is recommended.

9. Failure of the internal attachment welds may result in broken pieces of pump internal components carried over to the reactor pressure vessel and damage of vessel internals and core components. Weld inspection guidelines for the various pump designs need to be developed.

10. Leakage of borated water across LWR primary coolant pump case–to–cover gaskets can cause corrosion of the pump closure studs and corrosion of carbon steel pump body base metal. Corrective actions to prevent leakage include use of gaskets with better spring–back characteristics, proper gasket installation and cleanliness control, and proper stud tensioning practices. The leak–off lines between the inner and outer gaskets should be left unplugged and be instrumented so that leakage can be detected.

11. Volumetric examination of the closure studs, as presently required, should be supplemented with visual examinations to determine whether leakage has occurred. The use of the cylindrically guided wave technique should be considered. Another option would be to consider a leak–before–break analysis to evaluate closure integrity.

12. Use of conventional ultrasonic techniques to inspect pump shafts gives inconclusive and misleading results. A field evaluation of the modified cylindrically guided wave technique for shaft inspection is needed. Monitoring of the pump motor frame vibrations is recommended. Such monitoring can detect a circumferential crack in the pump shaft.

15.2 Pressurized Water Reactor Pressurizer

The pressurizer is a pressure vessel constructed, and inspected at frequent intervals, according to the ASME Code. It is not subjected to high neutron fluence, and the reactor coolant system coolant with which its internal surfaces are in contact is of high purity. The major problems associated with this system have been the safety and relief valves, which have failed to seat properly, leaked, failed to lift, had their set points drift, or been improperly installed, repaired, or inspected. The valve reliability question is an ongoing operational challenge throughout plant lifetime but is not necessarily a license–renewal issue and has not been addressed here.

The aging degradation mechanism that is pervasive throughout PWR pressurizers is fatigue. Low–cycle fatigue damage is caused by plant heatup/cooldown cycles, plant unloading and loading at power, step–load increases and decreases, reactor trips, hydrotests, etc. The surge–line nozzle and thermal sleeve are particularly affected by the insurge of relatively cooler hot–leg coolant and/or outsurge of pressurizer fluid associated with power changes. The spray–line head, the nozzle, and the thermal sleeve are very susceptible to fatigue damage caused by the subcooled spray actuations associated with power changes. The pressurizer walls may be susceptible to both the low–cycle fatigue damage caused by the plant operational transients and the high–cycle thermal fatigue caused by (a) thermal loads imposed by the subcooled spray on the pressurizer walls, (b) sloshing of the liquid at the steam–water interface, and (c) water–level changes caused by insurges, outsurges, and heater actuations. The key fatigue degradation sites are calculated to have high cumulative fatigue usage factors and include the pressurizer walls near the usual steam–water interfaces, the spray head, the spray– and surge–line nozzles, and the thermal sleeves. The cast stainless steel spray heads are also susceptible to thermal aging (embrittlement) and erosion. The heater sheaths and sleeves are susceptible to wear caused by thermally induced rubbing and possibly stress corrosion cracking. Pressurizer manway bolts can and have been damaged by leaking primary coolant, which caused stress corrosion cracking. Leakage of borated coolant can also cause corrosion and wastage of the nearby low-alloy steel base metal. Potential failures include ductile tearing and through-wall cracks, leading to (a) leakage of the primary coolant (pressurizer walls near the usual steam-water interface and/or surge- or spray-line nozzles), (b) excessive erosion and/or cracking of the spray heads, (c) heater sheath and/or sleeve cracks, and (d) manway cover leakage.

Other than the associated valves, at least two subcomponents can be expected to require replacement. These are (a) the heater elements, which can be replaced at refueling outages on a regular basis (in fact, the original designs facilitate ease of maintenance), and (b) the spray head, which can be replaced by a relatively minor operation. Otherwise, the pressurizer may be a good candidate for life extension, using additional analyses and inspections as outlined below.

Critical degradation sites, stressors, degradation mechanisms, potential failure modes, and appropriate inservice inspection methods for pressurizers are listed in Table 15.2.

Several supporting analyses and tests will be required to determine the residual life of the pressurizer. Inclusion of additional requirements in the ASME Code, Section XI, would be appropriate. The following are the recommendations for more detailed analyses and tests:

1. Reanalysis of the fatigue life at the locations with high fatigue usage factors will be necessary, possibly with more refined thermal models and with better definition of actual temperatures and temperature change rates during transient conditions. This should include better definition of the high-cycle events, such as verifying that sloshing does or does not occur, and realistic numbers of spray cycles. The MIT experimental results can probably be used to quantify the accuracy of pressurizer transient prediction models. The location of critical welds, such as at the steam-water interface, would have to be determined on a case-by-case basis, depending on the manufacturing technique.

2. In conjunction with Item 1, there also must be justification that the fatigue curves used in any revised fatigue analysis are applicable to metal exposed to a PWR environment. Corrosion fatigue curves, including the high-cycle region, should be developed. (This item is applicable to all primary system components.)

3. A comprehensive inspection plan to detect cracks will be necessary (probably using current ultrasonic test methods). A program to evaluate crack growth will also be necessary for these locations where cracks are found. Development of a technique to monitor for cracks at heater sleeve locations is needed. An inspection plan to monitor spray head erosion is also recommended.

4. Adequate monitoring techniques that will detect boric acid leakage and corrosion before it causes significant degradation of the primary coolant pressure boundary should be developed.

5. The cast stainless steel spray heads may be susceptible to erosion and thermal embrittlement during operation. However, this problem can be solved by replacing the degraded spray heads.

15.3 Pressurized Water Reactor Surge And Spray Lines And Nozzles

A summary of the important degradation sites, stressors and mechanisms, the potential failure modes, and the current ISI methods is presented in Table 15.3. Evaluation of the pressurizer surge and spray line piping and nozzles indicates that stratified-flow conditions may occur and may lead to fatigue damage that can limit the useful life of pressure boundary components. A complete accounting of actual in-plant thermal loadings is needed in order to accurately predict the residual life of those components. Once the loadings are more accurately defined, an appropriate prediction of fatigue life can be made and an appropriate inservice inspection program can be implemented with state-of-the-art techniques.

The conclusions and recommendations related to aging degradation of the pressurizer surge and spray lines and nozzles are as follows:

1. The horizontal portions of the surge line subjected to stratified flows should be analyzed to determine whether a catastrophic rupture rather than a leak-before-break can take place. Stratified flows cause significant fatigue damage to the horizontal portions of

Table 15.2. Summary of degradation processes for pressurizers

Rank	Degradation Site	Stressors	Degradation Mechanisms	Failure Modes	ISI Method
1	Vessel shell near steam–water interface	Thermal and mechanical stresses caused by plant operational transients, water level changes (due to insurges, outsurges and heater actuations), sloshing, subcooled spray impact and hydrotests; PWR coolant	Fatigue (possibly corrosion assisted)	Crack leading to leak	Volumetric
2	Spray line nozzle	Thermal and mechanical stresses caused by plant operational transients, spray actuations and hydrotests; PWR coolant	Fatigue (possibly corrosion assisted)	Crack leading to leak	Volumetric, surface
3	Surge line nozzle	Thermal and mechanical stresses caused by plant operational transients, insurges, outsurges and hydrotests; PWR coolant	Fatigue (possible corrosion assisted)	Crack leading to leak	Volumetric, surface
4	Heater sheathes and sleeves	Residual stresses, PWR coolant, thermally induced rubbing	Stress corrosion cracking, wear	Crack leading to leak or metal loss	Visual for external penetration welds
5	Manway bolts	Steam leakage	Stress corrosion cracking	Bolt breakage, leak	Volumetric (>2 in.), visual ($\leq$2 in.)[a]
6	Supports (keys, skirts and shear lugs)	Thermal stresses, seismic events	Fatigue	Crack leading to loss of support; overstress of piping	Volumetric, visual
7	Thermal sleeve	Flow–induced vibration, thermal stress	Fatigue	Loss of thermal sleeve to protect nozzles	None
8	Spray head	Spray flow, temperature, thermal stress caused by spray actuation	Erosion, embrittlement, fatigue	Loss of spray capability	None
9	Heater elements	Temperature	Burnout	Loss of heating capability	None

a. One inch = 25.4 mm.

Table 15.3 Summary of degradation processes for pressurizer surge and spray lines and nozzles

Rank	Degradation Sites	Stressors	Degradation Mechanisms	Potential Failure Modes	ISI Methods
1	Pressurizer Surge Line and Nozzle	Thermal transient stress loadings Stratified flow stress loadings, thermal striping	Low- and high-cycle thermal fatigue	Crack initiation and propagation leading to possible through-wall leak, pipe rupture	Piping and nozzle welds inspected volumetrically at each of the four 10-year intervals
		Thermal shock		Thermal sleeve cracking	
		Flow-induced mechanical vibration	Mechanical fatigue	Thermal sleeve cracking, crack initiation in nozzle	
		Temperature	Thermal embrittlement	Through-wall leakage	
2	Pressurizer Spray Line and Nozzle	Thermal transient stress loadings Stratified flow stress loadings (pipe only) thermal striping	Low- and high-cycle thermal fatigue	Crack initiation and propagation leading to possible through-wall leak Thermal sleeve cracking	Piping and nozzle welds inspected volumetrically at each of the four 10-year intervals
		Flow-induced mechanical vibration	Mechanical fatigue	Thermal sleeve cracking, crack initiation in nozzle	

the surge line, but were not accounted for in the original design. Results from a recent analysis of one PWR plant suggest that a surge line subjected to stratified flows will leak before it will rupture.

2. The leak-before-break approach may not be workable for small diameter piping such as spray lines that also experience significant fatigue damage caused by stratified flows.

3. More frequent inservice inspection of nozzle welds with high fatigue usage factors is needed. Some of the nozzle welds have a fatigue usage factor as high as 0.7 resulting from design transients alone.

4. Because stratified flows are likely to cause fatigue damage to the base metal in the horizontal sections of the surge and spray lines, inspection of the affected regions in the base metal needs to be included in the inservice inspection program. Current ASME Section XI inservice inspection guidelines do not require inspection of the base metal.

5. Acoustic emission techniques that reliably can detect the growth of fatigue cracks in both the welds and base metal of stainless steel piping should be developed. These techniques can then be used along with other nondestructive testing methods to characterize these cracks.

6. On-line fatigue monitoring should be used to measure coolant temperatures, pressures, and flow rates, and pipe wall temperatures. These data could be used to accurately calculate the accumulated low-cycle fatigue damage. Detailed and accurate records of the transients causing fatigue damage are not available. Some plants are already measuring these data.

7. A research program is needed to estimate the magnitudes and frequency content of the fluctuating loads imposed by thermal striping. These data are needed to estimate fatigue crack initiation times for the surge and spray lines.

8. Smaller temperature differences between the pressurizer and the hot leg coolant during heatup and cooldown can reduce fatigue damage to the surge line.

9. Plant operating procedures should specify full flow through the spray line and continuous spray during plant cooldowns. This practice will mitigate spray line fatigue damage caused by stratified flows and thermal shock. Some plants have already revised their operating procedures to this effect.

10. Properly sized bypass valves can provide full flow through the spray lines during normal operation and mitigate fatigue damage.

11. Replacing relatively short horizontal sections of spray piping with sloped sections can help prevent stratified flows.

15.4 Pressurized Water Reactor Coolant System Charging And Safety Injection Nozzles

A summary of the important potential degradation sites, stressors caused by operational transients, degradation mechanisms, and potential failure modes is presented in Table 15.4. The evaluation of the charging nozzles and safety-injection nozzles indicates that these nozzles are subject to fatigue damage caused by thermal-shocks, stratified flows, and flow-induced vibrations. Stratified flows were not fully considered in the original design analysis. Fatigue can limit the useful life of these components.

The conclusions and recommendations related to aging degradation of the PWR charging and safety injection nozzles are as follows:

1. The charging and safety injection lines subjected to stratified flows should be analyzed to determine whether a catastrophic rupture, rather than a leak-before-break, can take place. Leakage from faulty valves has resulted in thermal stratification and striping loads that have caused through-wall cracks in welds and base metal, and were not accounted for in the original design.

2. The high-stress locations in the base metal that are subjected to thermal striping and stratification need to be inspected. Current inservice inspection requirements do not include inspection of the base metal.

3. Current inservice inspection requirements are not adequate to detect thermal fatigue cracks, and need to be upgraded. Acoustic emission techniques may be used along with ultrasonic testing methods to characterize fatigue cracks.

4. On-line monitoring methods are needed to detect leakage from faulty or degraded valves. Such leakage has imposed thermal loads on the safety injection lines, causing through-wall cracks.

5. Appropriate methods are needed to monitor the charging and safety injection nozzle operational transients, so that the fatigue damage can be accurately estimated. The nozzles are subjected to stressors during plant operation that are considerably different and possibly more significant in magnitude and frequency than those considered in the original design.

15.5 Pressurized Water Reactor Feedwater Piping And Nozzles

Significant feedwater piping degradation caused by erosion-corrosion (including flow-assisted corrosion and cavitation damage); stratified flow and thermal shock-induced fatigue; and mechanical fatigue caused by flow-induced and mechanical vibrations and water hammer events has occurred. In many cases, these factors were not adequately considered in the plant

Table 15.4. Summary of degradation processes for PWR RCS charging and safety injection nozzles

Rank	Degradation Site	Stressor	Degradation Mechanisms	Potential Failure Modes	ISI Methods
1	Charging nozzle	Thermal–transient stress loadings	High– and low–cycle thermal fatigue	Crack initiation and propagation leading to possible through wall leak	Piping and nozzle welds inspected volumetrically at each of the four 10–year intervals
		Thermal–shock stress loadings	High– and low–cycle thermal fatigue	Thermal sleeve cracking	—
		Flow–induced vibration	Mechanical fatigue	Thermal sleeve cracking, crack initiation in nozzle	—
2	Safety injection nozzle	Thermal–transient stress loadings	High– and low–cycle thermal fatigue	Crack initiation and propagation leading to possible through wall intervals	Piping and nozzle welds inspected volumetrically at each of the four 10–year intervals
		Thermal–shock stress loadings	High– and low–cycle thermal fatigue	Thermal sleeve cracking	—
		Stratified–flow stress loadings, thermal striping	High– and low–cycle thermal fatigue	Crack initiation and propagation leading to possible through–wall leak	—
		Flow–induced mechanical vibration	Mechanical fatigue	Thermal sleeve cracking, crack initiation in nozzle	—

design and safety analysis, and the required inservice inspections have not been adequate to detect the degradation before the piping failed. This aging degradation has occasionally resulted in catastrophic failure of a feedwater pipe. Fatigue analyses were (and still are) not required, nor are there any explicit requirements to evaluate high-cycle vibration and fatigue except in the initial testing phase of the systems. Water hammer events also cause fatigue damage and must be examined when determining the residual life of a system. The phenomena and extent of degradation in PWR feedwater lines are not sufficiently defined (in terms of plant parameters and cycles), to quantitatively predict feedwater system lifetimes. Nor have most secondary system piping segments been inspected with great rigor. Therefore, the potential exists for a PWR feedwater system to generate degradation that will allow a dynamic event, such as an earthquake or a water hammer, to suddenly fail a pipe, with no advanced warning such as a leak before break.

A broad-based approach has been taken to resolve these problems. An NRC Bulletin was issued that requires utilities to institute more detailed inspection plans for secondary system piping. EPRI has developed the CHEC computer code to assist in identifying areas to be inspected. This code is being used by utilities, in conjunction with engineering judgment and experience in other plants (e.g., Trojan), to select the sites for more detailed inspections. EPRI has also assisted utilities by evaluating the type of nondestructive testing methods that might be used for these inspections. Most utilities have completed initial inspections of their feedwater and condensate piping. Finally, the ASME Section XI Committee is drafting revised guidelines for the inspection of secondary-side piping.

The degradation sites for the feedwater system are ranked and listed in Table 15.5. The feedwater nozzle and piping inside containment are ranked the highest, because a break at this point cannot be isolated from the steam generator and results in rapid blowdown of the steam generator. The piping near fittings and geometric discontinuities is ranked next because of the erosion-corrosion problems that have occurred at those locations.

The conclusions and recommendations related to degradation damage in PWR feedwater piping are as follows:

1. Severe erosion-corrosion degradation of carbon steel feedwater piping can occur and may lead to catastrophic failure. The erosion-corrosion damage can be very localized. Reliable nondestructive inspection methods are being developed that effectively provide 100% coverage of the area under investigation and ensure that minimum wall thicknesses are detected. The results of thickness measurements should be evaluated considering the highest possible transient pressure.

2. Use of on-line monitoring methods to determine erosion-corrosion damage needs to be evaluated because of significant uncertainty regarding the erosion-corrosion rates. Thickness measurements should be used to assess the current wall thinning models and revise the guidelines, as needed, for identifying the sites that are susceptible to erosion-corrosion. On-line monitoring methods are not needed if the erosion-corrosion damage is effectively mitigated.

3. The secondary water chemistry (including pH level, oxygen content, and impurities), temperature, and bulk flow velocity; the piping layout; the smoothness of the piping inside surfaces; and the chemical composition of the piping material affect the rate of erosion-corrosion damage. Control of these parameters can mitigate carbon steel erosion-corrosion damage. However, a change in one of the system parameters, such as water chemistry or temperature, may have adverse affects on other plant components. For example, an increase in the oxygen content in the feedwater will tend to reduce the feedwater piping erosion-corrosion damage but may degrade the steam generator tubes. Also, the fatigue-crack-growth rate in carbon steel piping may increase with an increase in oxygen content. Obviously, caution is warranted prior to implementing any changes in system parameters.

4. The use of stainless steel coatings needs to be evaluated as a method to mitigate erosion-corrosion damage to feedwater piping. Stainless steel coatings have been successfully used in some foreign power plants to eliminate erosion-corrosion problems in steam lines.

5. The inside surfaces near any repair welds should be as smooth as possible. Rough inside surfaces can create turbulence in the flow that may induce flow-assisted corrosion; and if the fluid temperature is near saturation, they may provide nucleation sites for formation of gas bubbles that subsequently collapse and cause cavitation damage.

Table 15.5. Summary of degradation processes for PWR feedwater piping and nozzles

Rank	Degradation Sites	Stressor	Degradation Mechanisms	Potential Failure Modes	ISI Methods
1	Feedwater nozzle and piping inside containment, sites in horizontal piping runs in vicinity of mixing layer	Flow velocity, O_2 content and pH level in feedwater, impurities, stratified flows, thermal shocks, water hammer, thermal transients	Erosion–corrosion, high- and low-cycle thermal fatigue, mechanical fatigue, mechanical overload	Rupture from wall thinning, leakage through fatigue cracks, rupture caused by water hammer	Ultrasonic testing, radiography[a]
2	Feedwater piping near fittings	High flow velocity, O_2 content and pH level in feedwater, impurities, water hammer, thermal transients	Erosion–corrosion, mechanical and thermal fatigue	Rupture from wall thinning, leakage through cracks	Ultrasonic testing, radiography[a]
3	Geometric discontinuities on inside surface of piping	Flow velocity, O_2 content and pH level in feedwater, impurities, water hammer	Erosion–corrosion, mechanical fatigue	Rupture from wall thinning	Ultrasonic testing, radiography[a]

a. Currently being performed but not included in ISI requirements.

6. The feedwater piping and nozzles also are subjected to fatigue damage from stratified flow, thermal shock, flow–induced vibration, and equipment vibration loads. The fatigue damage will ultimately lead to leakage of feedwater under normal operation. However, a pipe section significantly weakened by fatigue damage may fail catastrophically if subjected to a water hammer or a pressure pulse. Acoustic monitoring of the feedwater nozzles and horizontal portions of the piping may help to detect any crack growth.

15.6 Pressurized Water Reactor Control Rod Drive Mechanisms And Reactor Internals

Many of the factors relating to lifetime predictions of control rod drive mechanisms are unknown. While fatigue usage of pressure housings can be calculated, there are still many subcomponents for which no suitable lifetime prediction information is available. These include the insulation breakdown of the electrical components and wear of the latching mechanisms. We know CRDMs have generally operated successfully for a number of years (over 20 years at some Westinghouse–designed plants and over 15 years at some Combustion Engineering plants), but there is not enough information at present to predict the overall lifetime. Lifetime tests show that Combustion Engineering CRDMs can probably operate for a minimum of 30,480 m (100,000 ft) of travel,[a] and Westinghouse reports a lifetime in excess of 2.5 million steps, but we do not have the statistical data base from CRDM fragility tests to satisfactorily compute the probabilities needed to predict the expected life. Both Combution Engineering and Westinghouse attribute the operating problems experienced to date to random malfunctions and not to aging factors, although some types of CRDM failures have been increasing with time. Combustion Engineering expects the motor assembly and drive shaft to experience the greatest wear or fatigue.

Based on the information available to date, the critical locations with respect to plant aging are listed in Table 15.6. The potential failure locations that can result in primary coolant leakage are ranked highest. There are several activities that should be conducted to extend our knowledge of CRDM aging related issues. These include the following:

1. Ten percent of the peripheral CRDM housing welds are inspected during each inservice inspection interval, but the welds of the interior CRDMs are generally inaccessible and not inspected. Techniques should be developed to ascertain the integrity of the welds that are inaccessible for inspection.

2. Adequate monitoring techniques are needed to detect boric acid leakage before it causes significant corrosion of the primary coolant pressure boundary. Leaking borated coolant from a CRDM or instrument housing can cause corrosion of the external CRDM components and the vessel carbon steel base metal.

3. Evaluation of the thermal embrittlement of cast stainless steel CRDM pressure housings is needed.

4. The electrical parameters (for example, the current required) which indicate the degree of wear, friction, or binding in CRDM should be measured periodically.

5. Techniques for measuring the cumulative length of lead screw travel or counting the number of latch steps should be developed. This information should be recorded and could then be compared to the CRDM life test results to determine the need for CRDM replacement.

6. The CRDMs should be periodically pulled and inspected for excessive wear. After inspection they could be rotated to different rod banks to allow for more even wear. Careful measurements of the wear would facilitate better residual life estimates.

7. Life tests for the latch assemblies (roller nut, rack–and–pinion, and magnetic jack) and the electrical insulation are needed. If the lifetimes are found to be insufficient, alternate materials with extended lifetimes could be considered. Vendor tests have shown that CRDMs are suitable for the estimated travel required for 40 years, but have not established absolute lifetimes in feet of travel for all designs.

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a. C. W. Ruoss, private communication, Combustion Engineering, February 3, 1987.

Table 15.6. Summary of degradation processes for PWR CRDMS

Rank	Degradation Sites	Stressors	Degradation Mechanisms	Potential Failure Modes	ISI Methods
1	Pressure housing	Thermal stress, high–temperature water	Thermal embrittlement, low–cycle fatigue	Crack leading to leak	Volumetric or surface[a]
2	Latch assembly	Loose parts, impacting, metal–to–metal contact	Fretting, wear spalling	Binding, stuck rods	None
3	Coil stack	Moisture, temperature, radiation	Insulation breakdown, electrical shorting	Dropped rods	None
4	Drive rod	Rubbing, impacting	Wear, low cycle fatigue	Uncoupling of CRA	None
5	External components	Boric acid (if leak is present)	Boric acid corrosion	Leaks	None

a. 10% of peripheral CRDMs per inspection interval.

One major advantage to CRDM life extension is that many of the subcomponents can be replaced relatively easily. This is especially true of the electrical components, which are located outside of the pressure housing. The technology for CRDM replacement is available, as full changeouts have been made.

The critical locations with respect to reactor internals aging in order of importance are listed in Table 15.7. These generally are concerned with bolts and other smaller parts loosening or breaking, and larger components cracking or undergoing excessive vibration. Some recommendations with respect to the reactor internals are as follows:

1. Monitor the wear of the in–core instrument housings (including the thimble tubes) and CRDM guide tubes.

2. Develop advanced inservice inspection procedures that can predict incipient failures. Such a technique for bolts is particularly needed.

3. Develop high–cycle fatigue curves for high–strength steel bolting materials.

4. Establish research programs to determine the combined effect of radiation and temperature, causing embrittlement of austenite and ferrite phases, respectively, in the cast stainless steel components.

5. Establish research programs to determine the effect of radiation and cumulative fluence on the mechanical properties of reactor internal materials. Tests of actual core specimens would be helpful.

Table 15.7. Summary of degradation process for PWR reactor internals

Rank	Degradation Sites	Stressors	Degradation Mechanisms	Potential Failure Modes	ISI Methods
1	Instrument tubes (Thimble tubes)	Flow–induced vibration, high–temperature water	Fretting, high–cycle fatigue, wear	Leaks, cracks, loose parts	Eddy–current
2	Thermal shield and bolts	Flow–induced vibration, high–temperature water, bolt preload stress, radiation	High–cycle fatigue, IGSCC, stress relaxation	Broken bolts, cracks, loose parts	Visual[a]
3	Core barrel and bolts	Flow–induced vibration, high–temperature water, bolt preload stress, radiation	High–cycle fatigue, IGSCC, stress relaxation	Broken bolts, cracks, loose parts	Visual[a]
4	Upper and lower core support structures	Flow–induced vibration, high–temperature water, bolt preload stress, radiation	High–cycle fatigue, IGSCC, stress relaxation, irradiation and thermal embrittlement	Broken bolts, cracks, loose parts	Visual[a]

a. Accessible surfaces of removable components and welds of integrally welded components.

6. Perform an alternate material study to develop bolts and pins with extended lifetimes. This would include different heat treatments of Alloy X–750, Alloy 718, and A–286.

7. Establish vibration monitoring programs using the ex–core and/or in–core neutron noise detectors in conjunction with other monitoring instruments and structural finite element models.

15.7 Countermeasures For Tube Failures In Pressurized Water Reactor Steam Generators

The important degradation sites, stressors, degradation mechanisms, potential failure modes, and current ISI requirements associated with PWR steam–generator tubes are summarized in Table 15.8. Some of the degradation mechanisms, that is, intergranular stress corrosion cracking, intergranular attack, pitting, wastage, and denting have caused more tube failures in the recirculating type steam generator than in the once–through steam generators. Fretting, erosion–corrosion, and fatigue damage is receiving more attention because of recent failures; however, these problems are limited to particular steam generator designs. Table 15.9 summarizes the techniques for mitigating the damage resulting from the important aging degradation mechanisms. Table 15.9 also summarizes the improvements made in new/replacement steam generators and other secondary side components to reduce PWR steam generator tube degradation. Long–term field–experience data are needed to assess the effectiveness of the various countermeasures. Inservice inspection methods and quantitative models are needed to estimate the magnitude and rate of the damage. The conclusions and recommendations regarding the countermeasures for steam generator tube failures are as follows:

1. The highest priority is given to preventing faulted conditions in the secondary water chemistry. Some water chemistry transients can cause large–scale damage in a short time. Remedies include preventing condenser leakages, improving makeup water purity, frequent water chemistry checks, and preventing resin or chemical releases from condensate polishers. Installing titanium tubing in the condensers reduces the possibility of leaks. However, titanium tubing is susceptible to fatigue caused by vibrations. Impurities in the secondary water can be minimized by ultrafiltration of the makeup water, feeding makeup water through condensate polishers, and reducing the quantity of makeup water by recycling blowdown water using a recovery system. The Steam Generator Owners' Group guidelines for continuous monitoring and control of water chemistry should be followed to reduce impurities in the secondary water. Because copper enhances denting and pitting processes, it is desirable to eliminate copper and copper containing alloys from the secondary side.

2. In several plants, condensate polishers are considered unnecessary and unsafe because they can cause damage to the tubing if resins or chemicals are accidentally released from misoperation of or mechanical damage to the condensate polishers. The operators of some plants believe that condensate polishers provide the only defense against faulted water chemistry conditions. Condensate polishers routinely remove impurities and mitigate degradation processes in steam generators. Additional safety can be provided by installing filters between the polishers and steam generators to collect any accidentally released resins.

3. Plant studies have demonstrated that certain chemical additives, that is, boric acid and morpholine, will mitigate intergranular attack, intergranular stress–corrosion cracking, denting of the steam generator tubes, and general corrosion of the carbon steel components in the feed–water system. These chemical additives do not adversely influence other plant components.

4. Several utilities have successfully used secondary–side cleaning methods, such as lancing with a high–pressure water jet and subsequent chemical cleaning, that remove residues. Removal of copper–bearing sludge from the secondary side allows the detection of some defects, such as pitting, during inservice inspection. Several methods have also been developed to clean tubesheet crevices with hot soaks and tubesheet crevice flushing techniques.

Table 15.8. Summary of degradation processes for steam generator tubes

Rank[a]	Degradation Site	Stressors	Degradation Mechanisms	Potential Failure Modes	ISI Method
1	Inside surface of U–bends, roll–transition, and dented tube regions	Tube rolling and U–bend stresses, primary coolant, and residual stresses introduced by denting	Pure water stress corrosion cracking	Cracking, leakage	Eddy–current testing
2	Outside surface of hot–leg tubes in the tube–to–tube sheet crevice region	Alkaline environment, presence of SO_4 and CO_3 anions	Intergranular stress corrosion cracking, inter–granular attack	May eventually result in cracking	Eddy–current testing
3	Cold–leg side in sludge pile or where scale containing copper deposits is found	Brackish water, chlorides, oxygen, and copper	Pitting	Local attack and tube thinning may eventually lead to a hole	Eddy–current testing, optical scanner system, souic leak detector system
4	Outside surface of tubing above tube sheet	Phosphate chemistry, chloride concentration, resin leakage from condensate polisher bed	Wastage (thinning)	Uniform attack, tube thinning may eventually wear out the material	Eddy–current testing
5	Tubes in the tube–support regions	Oxygen, copper oxide, chloride, temperature, pH, crevice conditions	Denting	Flow blockage in tubes caused by plastic deformation	Helium leak and sonic leak testing, optical probes, hydrogen evaluation monitoring, pulse–echo ultrasound method
6	Contact points between tube and antivibration bar	Flow–induced vibrations	Fretting	Wearing out of material caused by rubbing and/or fatigue	Eddy–current testing

Table 15.8. (continued)

Rank[a]	Degradation Site	Stressors	Degradation Mechanisms	Potential Failure Modes	ISI Method
7	Inadequately supported tube near upper support plate	Residual stresses and reduced damping caused by denting, flow–induced vibrations	High–cycle fatigue	Tube rupture (double–ended guillotine break)	Eddy–current testing
8	Tubes where denting has occurred	Thermal transients	Low–cycle fatigue	Primary–to–secondary leaks	Eddy–current testing
9[b]	Once–through steam generator tubes	Velocities, sizes, shapes, impact angle, and hardness of particles, thermal transients	Erosion–corrosion from impingement of particles, low–cycle fatigue	Wearing out of material, primary–to–secondary leaks	Eddy–current testing
10[b]	Once–through steam generator tubes in the upper (tube–sheet) region	Chemicals, (localized corrosion) vibrations	Fatigue	Primary–to–secondary leaks	Eddy–current testing

a. Based on operating experience for steam generator defects.

b. Denotes once–through steam generator (items 7 and 8 do not reflect rank order). First 6 items are for recirculating steam generators.

Table 15.9. Summary of countermeasures for tube failures in PWR steam generators

Mechanism	Mitigation of Damage in Existing Tubes[a]	Improvements in New/Replacement Steam Generators
Primary side SCC	Roto/Shot Peen to improve residual stresses; anneal the U–bends and control the denting problem.	Use Alloy 690 tubes with optimum microstructure and a maximum yield strength of about 380 MPa (55 ksi); and minimize/eliminate residual stresses
Secondary Side Defects:		
Intergranular stress corrosion cracking, intergranular attack	Control alkaline impurities, eliminate acid chlorides, flush tubesheet crevices, use hot soak, lance, and chemically clean; neutralize crevice alkalinity; add boric acid; and roll tubes to eliminate crevices.	Use Alloy 690 tubes with optimum microstructure,eliminate tubesheet crevices, improve access for lancing and cleaning, increase blowdown capacity, shot peen OD, and design flow to avoid sludge accumulation.
Pitting	Eliminate condenser leakages; preclude ingress of air/oxygen, acid chloride, and copper in water.	Use titanium or stainless steel condenser tubes, eliminate Cu alloys in feed train, and resistant tube materials.
Denting	Eliminate ingress of air/oxygen, acid chlorides, and copper in water; use leak–tight condensers, use hot soaks.	Use strict water chemistry controls, use stainless steel support structures, and design to preclude stagnant water in annuli, and titanium condenser tubes.
Wastage	Use AVT water chemistry; eliminate hideout chemical concentrations; use sludge lancing and chemically clean; use hot soaks; hot blowdown and flushing; preclude resin ingress.	Design flow to preclude hideout and chemical concentrations; minimize sludge formation; improve access for cleaning, and increase blowdown capacity.
Fatigue in OTSG[b] (thermal and environmental)	Control chemistry and modify to preclude dryout of water particles with impurities on tubes near the open lane.	—

a. Repair generally consists of plugging or sleeving or various new expansion joints in the tube–sheet region. Various size sleeves and minisleeves have been used.

b. OTSG = once–through steam generator

5. Shot and rotopeening techniques have been used to introduce residual compressive stresses on the tube inside surface to mitigate pure water stress corrosion cracking (PWSCC). However, no NDE method is available to measure the residual stresses. Effectiveness of these techniques depends upon process controls.

6. Alloy 600 and 690 microstructures and heat treatments have been developed that result in an increased resistance to PWSCC in laboratory tests. However, further research is needed to gain a fundamental understanding of the mechanisms of PWSCC.

7. Grain boundary carbides provide increased resistance to PWSCC; however, sensitization (grain boundary chromium depletion) should be avoided to ensure resistance to secondary–side faulted chemistry conditions. Thermal treatments can produce resistance to both

primary and secondary-side degradation processes.

8. In situ stress relieving of highly stressed regions, such as U-bends, has been used in some plants to prevent PWSCC in tubing that has not cracked. Sufficient care should be taken to avoid formation of chromium-depleted zones near grain boundaries. The use of increased pH in the primary coolant to mitigate PWSCC is being evaluated. The increased pH may be achieved via higher lithium or through use of enriched boron.

9. The material specifications for PWR steam generator tubing (Alloy 600 or 690) should require a maximum yield strength of about 380 MPa (55 ksi), which will limit the maximum residual stresses. Presently, there is no maximum yield strength requirement in the current ASME Code specifications for these materials.

10. The current allowable NDE flaw-indication criterion specified by the NRC is conservative when the accepted flaw does not grow rapidly during plant operation. Efforts to reduce the uncertainties in the NDE results, quantify flaw growth rates, and determine safety margins during operations should be continued.

11. Several effective sleeving designs have been developed recently to cover defects in the tubes near the tube-sheet region. Leak tightness of sleeved tubes is monitored in subsequent plant operation. Use of sleeves introduces residual stresses that cannot be measured, presents difficulties for future inspections, forms crevices on the primary side, introduces geometric stress raisers, and poses concerns in the event of a double-ended tube break at the sleeve joints. Therefore, the field performance of the various sleeve designs should be monitored.

12. Plugging is the only remedy when unacceptable flaws are detected in regions away from the tubesheet. However, some plugs are susceptible to PWSCC (plugs with low mill-anealing temperatures). If PWSCC causes a plug failure instead of leakage, the fragments of the failed plug may enter the tube with sufficient velocity to puncture the tube and possibly damage neighboring tubes. Plugs can be removed for future repair if needed. Plugging too many tubes is likely to affect the steam generator thermalhydraulics. Inservice inspection methods to assess the integrity of plugs need to be developed.

13. A nickel plating technique is being developed to repair IGSCC cracks in steam-generator tubes. Nickel plating generates very low residual stresses and does not require a subsequent heat treatment, and it can be applied anywhere in the straight part of the tube. It also allows later access to areas above the section repaired in case of further damage, whereas sleeving does not. An ultrasonic inspection method has been developed to detect axial and circumferential cracks in a nickel-plated region.

14. Successful steam-generator replacements have been accomplished at several PWR plants. The replacement steam generators are expected to have a longer life because of improved designs and materials. The design improvements include elimination of crevices, lower residual stresses, and improved access for secondary-side lancing and chemical cleaning. The improved materials include thermally treated Alloy 690 for the tubes and ferritic stainless steels for the tube-support structures.

15.8 Boiling Water Reactor Containments

A summary of the important aging degradation sites, stressors, and mechanisms; potential failure modes; and current inservice inspection and test requirements for the BWR metal containments is presented in Table 15.10. The ranking of the sites is based on the consequences of the potential failure modes. Among the sites having the same failure modes, a site that is more susceptible to failure is ranked higher. The exterior surfaces of Mark I and Mark II containments are ranked higher because they are not easily accessible for inspection. The conclusions and recommendations for the metal containments are as follows.

1. Corrosion of the drywell shell is the primary safety concern. Crevice corrosion, pitting, uniform corrosion, and microbially influenced corrosion are degradation mechanisms that can attack the outside surface of the drywell. Use of nondestructive inspection methods to measure the thickness of the drywell shell at selected sites is recommended to assess any damage from corrosion. The magnetic particle inspection technique for

Table 15.10. Summary of degradation processes for BWR metal containments

Rank	Degradation Sites	Stressors	Degradation Mechanisms	Potential Failure Modes	ISI Methods
1	Exterior surfaces of Mark I drywell base near sand pocket	Moisture, microorganisms degraded fill material	Uniform corrosion, crevice corrosion, microbially influenced corrosion	Leakage of radioactive gases	Leakage testing (10 CFR 50 Appendix J)
2	Exterior surfaces of Mark I and Mark II drywell	Degraded fill material, moisture	Crevice corrosion, uniform corrosion, pitting	Leakage of radioactive gases	Leakage testing (10 CFR 50 Appendix J)
3	Embedded shell region	Cyclic thermal loading, corrosive environments	Thermal fatigue, crevice corrosion, pitting	Loss of structural integrity	None
4	High–energy pipe line penetrations, hatches, vent lines	Cyclic thermal loading, pressure testing, corrosive internal environments	Thermal and mechanical fatigue, environmentally assisted fatigue	Leakage of radioactive gases	Visual inspection, leakage testing (10 CFR 50 Appendix J)
5	Stainless steel bellows	Corrosive internal environment, cyclic thermal loading, pressure testing	IGSCC[a] at heat–affected zone, TGSCC,[b] fatigue	Leakage of radioactive gases	Visual inspection, leakage testing (10 CFR 50 Appendix J)
6	Submerged portion of suppression pool	Corrosive internal environment, safety relief valve discharge tests, pressure testing, microorganisms	Differential aeration, mechanical fatigue, pitting, microbially influenced corrosion	Leakage of radioactive gases	Visual inspection, leakage testing (10 CFR 50 Appendix J)
7	Transition region from cylindrical to spherical portion of Mark I drywell, drywell shell at the core horizontal midplane elevation	Cyclic thermal loading, pressure testing, corrosive environments, neutron irradiation	Thermal and mechanical fatigue, environmentally assisted fatigue, irradiation embrittlement	Leakage of radioactive gases	Visual inspection, leakage testing (10 CFR 50 Appendix J)

Table 15.10. (continued)

Rank	Degradation Sites	Stressors	Degradation Mechanisms	Potential Failure Modes	ISI Methods
8	Dissimilar metal welds	Corrosive environments, cyclic thermal loading, pressure testing	Galvanic corrosion, fatigue	Leakage of radioactive gases	Visual inspection, leakage testing (10 CFR 50 Appendix J)

a. Intergranular stress corrosion cracking.

b. Transgranular stress corrosion cracking.

inspecting welds in the drywell through protective coatings should be field–tested, and included in the ASME Boiler and Pressure Vessel Code Section XI. Mitigation methods, such as cathodic protection, need to be developed to protect the drywell shell from corrosion. In addition, use of zinc–rich or phenolic coatings instead of red lead or epoxy coatings is recommended.

2. The embedded portion of the drywell is subjected to thermal cycles that may lead to separation at the concrete–metal interface and failure of any sealant at the interface. The embedded portion of the drywell shell is generally not coated during construction. Therefore, moisture can enter the gap at the interface and make the embedded portion of the drywell shell susceptible to crevice corrosion. The application and maintenance of a sealant at the interface can prevent moisture entry and, thus, provide protection against corrosion. Electromagnetic acoustic transducers need to be developed and field–tested to detect corrosion of the embedded portion of the drywell shell.

3. The submerged portions of the Mark I and Mark II suppression pool walls are susceptible to corrosion by differential aeration and microbially influenced corrosion. A good quality protective coating (for example, zinc–rich coating) needs to be maintained on the inside surface.

4. The sites of geometric discontinuities are subject to somewhat higher levels of thermal and mechanical fatigue than the overall containment, and the BWR corrosive environment may act synergistically with fatigue. Therefore, corrosion–fatigue data for the shell material in the typical BWR environments are needed.

5. The stainless steel bellows may undergo intergranular stress corrosion cracking in the heat–affected zones, and transgranular stress corrosion cracking in the unsensitized portions of the bellows. The nearby carbon steel pipe may be subject to galvanic corrosion caused by the dissimilar metal welds. The bellows are also subject to fatigue damage during normal operation and leak testing, and if there is any eccentricity, the reduction in fatigue life is likely to be an even more significant factor. The bellows constitute part of the containment pressure boundary, and their inside surfaces are not easily accessible for surface examination. Therefore, an NDE method to detect cracks in the bellows needs to be developed. In addition, it is prudent to test each ply for leakage during local leak testing of a two–ply bellows, and the alignment (that is, eccentricity) of the bellows should be maintained so as to minimize fatigue damage.

6. The drywell shell near the core midplane elevation may be subject to irradiation embrittlement. However, the data from the surveillance program at the Oak Ridge National Laboratory High–Flux Isotope Reactor (HFIR) suggest that the increase in the nil–ductility transition temperature of the drywell shell material will be negligible over the projected 40–year lifetime of a BWR plant.

There are ten BWR concrete containments in the United States: eight reinforced and two prestressed containments. All the BWR concrete containments except for one of the Mark III containments are completely enclosed in a reactor building that protects them from the degrading effects of the harsh external environment. A summary of the important degradation sites, stressors, degradation mechanisms, potential failure modes, and current inservice inspection and test requirements for the BWR reinforced concrete containments and the prestressed concrete containments is presented in Tables 15.11 and 15.12, respectively. These tables are similar to the corresponding tables for PWR containments presented in Volume 1 of this report. The conclusions and recommendations for the concrete containments also are similar to those for the corresponding PWR containments and are as follows.

1. Corrosion of the reinforcing bars is a major aging concern for the exposed Mark III containment. Internal chemical reactions could introduce cracks in the concrete, which may provide the harsh external environment access to the mild steel reinforcing bars. Reinforcing bars in the other concrete containments are less susceptible to corrosion because the reactor building provides protection from the harsh external environment.

2. Stray currents, if present, can also cause corrosion of the reinforcing bars. Additional information about the long–term degradation of reinforcing bars is needed. Relevant data

Table 15.11. Summary of degradation processes for BWR reinforced concrete containments

Rank	Degradation Sites	Stressors	Degradation Mechanisms	Potential Failure Modes	ISI Methods
1	Reinforcing bars	Corrosive external environment (Mark III), stray currents	Corrosion, fatigue	Loss of structural integrity	None
2	Mark I and Mark II suppression pool steel liner below water line	Cyclic thermal and mechanical loads, corrosive internal environment, microorganisms	Corrosion caused by differential aeration, microbially influenced corrosion, fatigue	Leakage of radioactive gases	Visual inspection, leakage testing (10 CFR 50 Appendix J)
3	Drywell steel liner, suppression pool steel liner above water line	Moisture, corrosive internal environment, cyclic thermal and pressure loads	Corrosion, fatigue	Leakage of radioactive gases	Visual inspection, leakage testing (10 CFR 50 Appendix J)
4	Concrete	Aggressive external environment, internal chemical reactions, nuclear heat, leakage testing	Cracking, spalling, loss of free water	Degradation of shielding properties	Visual inspection

Table 15.12. Summary of degradation processes for BWR Mark II prestressed concrete containment

Rank	Degradation Sites	Stressors	Degradation Mechanisms	Potential Failure Modes	ISI Methods
1	Posttensioning system anchors	Trapped water, steady–state stress	Hydrogen embrittlement, corrosion	Loss of stress	Tendon surveillance program, visual inspection
2	Posttensioning tendon wire or strand	Moisture, trapped water, microorganisms, steady–state stress	Pitting, microbially influenced corrosion, relaxation	Loss of stress	Tendon surveillance program
3	Suppression pool steel liner below water line	Cyclic thermal and mechanical loads, fatigue, corrosive internal environment, microorganisms	Fatigue, corrosion caused by differential aeration, microbially influenced corrosion	Leakage of radioactive gases	Visual inspection, leakage testing (10 CFR 50 Appendix J)
4	Drywell steel liner, suppression pool steel liner above water line	Moisture, corrosive internal environment, cyclic thermal and pressure loads	Corrosion, fatigue	Leakage of radioactive gases	Visual inspection, leakage testing (10 CFR 50 Appendix J)
5	Reinforcing bars	Stray currents	Corrosion	Loss of structural integrity	None
6	Concrete	Internal chemical reaction, nuclear heat, leakage testing	Cracking, spalling, creep, loss of free water	Degradation of shielding properties, loss of stress in posttensioning tendons	Visual inspection

should be collected from the older LWR containments and from facilities that have been shut down after extended service. Accelerated aging techniques should also be evaluated and, if appropriate, used to obtain additional data.

3. Hydrogen embrittlement of the posttensioning system anchors, pitting of the tendon wires, and microbially influenced loss of corrosion resistance of tendon grease are possible aging concerns for the posttensioning systems. Improved methods of monitoring degradation of anchors and decomposition of tendon grease are needed.

4. A comprehensive inservice inspection program is needed to identify and quantify degradation in reinforced and prestressed concrete containments.

15.9 Boiling Water Reactor Feedwater And Main Steam Line Piping

The principal mechanisms responsible for age-related degradation of the feedwater and main steam line piping in BWRs are erosion–corrosion, low–cycle fatigue, and high–cycle fatigue. The degradation sites, ranked in order of importance, are listed in Table 15.13.

There have been no fatigue analyses on most of the BWR feedwater and main steam line systems and the fatigue analyses that were done as part of the design of the Class 1 sections did not consider a number of important stressors (stratified flow, water hammers, etc.) and used ASME design curves, which are probably inappropriate (room temperature air data). In addition, erosion–corrosion damage has not been adequately accounted for in the design and inservice inspection of the BWR feedwater and main steam line systems, and the phenomena and extent of degradation caused by mechanical and flow–induced vibrations are neither well–understood nor sufficiently defined (in terms of plant parameters and cycles) to quantitatively predict feedwater system lifetimes. Therefore, it is possible that a dynamic event such as an earthquake or a water hammer might promote piping failure in these systems without a leak–before–break scenario.

The conclusions and recommendations related to the aging of BWR feedwater and main steam line systems are as follows:

1. Erosion–corrosion is a major degradation mechanism in carbon steel feedwater and main steam line piping, and may lead to catastrophic failure. Erosion–corrosion damage can be very localized. Reliable nondestructive inspection methods are being developed that effectively cover 100% of the area under investigation and consistently detect the minimum wall thicknesses. The results of thickness measurements should be evaluated considering the highest possible transient pressure. A pipe section significantly weakened by erosion–corrosion may fail catastrophically if subjected to a water hammer or a pressure pulse.

2. The feedwater piping is subject to fatigue damage caused by stratified flows, thermal shocks, flow–induced vibrations, and equipment vibrations. Under normal operation, this fatigue damage would ultimately lead to leakage of the feedwater. However, a pipe section significantly weakened by a fatigue crack may rupture if subjected to a water hammer or a high–pressure pulse. The use of on–line fatigue monitoring to assess low–cycle fatigue damage is recommended.[a] Use of acoustic emission monitoring to detect any crack growth in the feedwater nozzle and horizontal portions of the piping, including both base metal and welds, should be evaluated. Further development of this technique for crack growth may be needed. Acoustic emission already has been developed as a leak detection method.

3. General Electric experiments show that low–cycle fatigue cracks are initiated in carbon steel piping in a BWR environment at far fewer cycles than would be predicted using the in–air test data that forms the basis for the ASME design curve. Therefore, environmental fatigue data need to be developed for assessing fatigue damage to feedwater and main steam line piping.

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a. Temperature, pressure, and vibration of piping need to be monitored so transient thermal and mechanical loads caused by different stressors can be determined and the fatigue damage estimated. The stressors include heatups, cooldowns, operational transients, water hammers, steam hammers, stratified flows, and flow–induced and equipment vibrations.

Table 15.13. Summary of degradation processes for BWR feedwater and main steam systems

Rank	Potential Degradation Sites	Stressors	Degradation Mechanisms	Failure Modes	ISI Methods
1	Feedwater piping near fittings and at geometric discontinuities	Coolant chemistry, temperature, and flow rate; stratified flows; water hammers, vibration	Erosion–corrosion; fatigue; erosion	Rupture; leaks; cracks; large deformations	Volumetric and surface examination at welds; wall–thickness measurements
2	Main steam piping near fittings and at discontinuities	Coolant chemistry, temperature, and flow rate; moisture content in steam; steam hammers, temperature gradients; vibration	Erosion–corrosion; fatigue	Rupture; leaks; cracks: large deformations	Volumetric and surface examination at welds; wall–thickness measurements

4. Piping systems are subject to high–cycle fatigue damage caused by thermal striping, and flow– and equipment–induced vibrations. Criteria are needed for assessing high–cycle fatigue damage to carbon steel piping in a BWR environment and for developing acceptable limits for such damage.

5. Hydrogen water chemistry (HWC) reduces the oxygen level in the feedwater and therefore it is likely to decrease the fatigue crack growth rates in the carbon steel piping. However, the use of HWC may increase the rate of erosion–corrosion in the feedwater and main steam line if the oxygen level is not maintained above about 20 ppb. It is recommended that for at least one BWR plant, a baseline inspection of the piping wall thickness be performed before implementing HWC, and periodic inspections be done thereafter to identify any changes in the erosion–corrosion rates.

6. Use of an on–line monitoring method to determine erosion–corrosion damage (for example, isotope implantation) needs to be evaluated because there is significant uncertainty regarding erosion–corrosion rates. Also, thickness measurements from various plants should be used to assess the current wall thinning models and revise (as needed) the guidelines that identify the sites that are susceptible to erosion–corrosion.

7. Monitoring of oxygen content is needed so that fatigue–crack–growth rates and erosion–corrosion rates can be better estimated. Higher oxygen levels lead to higher fatigue–crack–growth rates, but lower erosion–corrosion rates.

8. Use of flame–sprayed stainless steel coatings has been successful in eliminating erosion–corrosion damage in carbon steel pipes containing wet steam in the Swedish BWRs. Use of this coating to reduce erosion–corrosion damage in feedwater piping needs to be evaluated.

15.10 Boiling Water Reactor Control Rod Drive Mechanisms And Reactor Internals

Many of the factors that must be understood for accurate CRDM lifetime predictions are unknown. Whereas the fatigue usage of the pressure housings can be calculated, IGSCC failures are very difficult to predict and there are still many subcomponents for which there is no suitable lifetime prediction information. These include the lifetimes of the valves and wear of the latching mechanisms. Some BWR CRDMs have operated successfully for over 20 years, but there is not enough information at present to predict the overall CRDM lifetime. Based on the information to date, the critical locations in order of importance are listed in Table 15.14.

Conclusions and recommendations for CRDMs are as follows:

Table 15.14. Summary of degradation processes for BWR control rod drive mechanisms

Rank	Degradation Sites	Stressors	Degradation Mechanisms	Potential Failure Modes	ISI Methods
1	Pressure housing, stub tube	Corrosive water, thermal stress, residual stress	IGSCC, fatigue	Crack leading to leak	Volumetric, surface
2	Latching mechanism (collet assembly and index tube)	Thermal transients, corrosive water, rubbing, impacting	Wear, IGSCC, fatigue	Binding, stuck rods	None
3	Piston seal C-spring	Preloads, corrosive water	IGSCC		None
4	Hydraulic control system	Thermal stress, corrosive water, debris, improper maintenance, overpressure, misalignment	Valve diaphragm embrittlement and cracking	Stuck rods, unintentional rod movement	None
5	Piston seals	Temperature, corrosive water	Embrittlement, wear	Stuck rod	None

1. IGSCC is the major degradation mechanism for the welds between the CRDM housing and the vessel lower head. Stub tubes are employed between the CRDM housing and the vessel in the older BWRs, and the heat-affected zones near the stub tube welds have experienced IGSCC cracks. It is difficult to inspect these welds, and remote inspections methods are needed to assess their integrity.

2. Hydrogen water chemistry (HWC) is an effective mitigation method for IGSCC damage. HWC significantly reduces the level of oxygen in the BWR coolant and, thus, eliminates a stressor required for the IGSCC mechanism to be present.

3. The CRDM internals should be inspected periodically for excessive wear damage. Monitoring of the cumulative number of insertions and withdrawals would help to make decisions related to CRDM replacement.

4. The diaphragms and discs in the solenoid-operated valves become brittle over time and break up. The broken diaphragm pieces may block the vent ports in the scram pilot valves, and plant safety may be compromised.

5. Thermal embrittlement is a potential degradation mechanism for the portions of the CRDM guide tubes and fuel supports, which are made of cast stainless steel. Because the guide tubes transmit most of the weight of the core to the vessel lower head, the damage caused by thermal embrittlement needs to be evaluated.

It is important to note that most of the CRDM subcomponents can be relatively easily replaced without having to replace the entire CRDM. Also, the technology for CRDM replacement is available, and full changeouts have been made. Thus, the CRDM issues are generally not those of feasibility.

Critical locations for the reactor internals are listed in order of importance in Table 15.15. The degradation mechanism of concern is IGSCC, which is

Table 15.15. Summary of degradation processes for BWR reactor internals

Rank	Degradation Sites	Stressors	Degradation Mechanisms	Potential Failure Modes	ISI Methods
1	Attachment welds to reactor vessel	Residual stress, corrosive water, temperature, flow–induced vibrations, dead weight	IGSCC, Fatigue	Crack progressing into reactor vessel	Visual[a]
2	Core shroud bolts	Preloads, corrosive water	IGSCC	Crack leading to loss of fuel geometry	Visual[a]
3	Core plate	Flow–induced vibrations, corrosive water, dead weight	IGSCC	Crack leading to loss of fuel geometry	Visual[a]
4	Jet pumps	Preloads, hydraulic loads, corrosive water, flow induced vibration, temperature	IGSCC, fatigue, erosion, thermal embrittlement	Loss of adequate core flow	Visual[a]
5	Top guide	Radiation, thermal stress, corrosive water, flow–induced vibrations, dead weight	IASCC, IGSCC	Crack leading to loss of fuel geometry	Visual[a]
6	Core spray spargers and piping	Flow–induced vibrations, corrosive water, temperature	IGSCC, fatigue	Loss of effective ECCS	Visual[a]
7	Feedwater spargers	Flow–induced vibration, corrosive water	Fatigue, IGSCC	Improper feedwater flow	Visual[a]
8	Fuel assembly supports	Corrosive water, flow induced vibration, radiation, temperature, dead weight of fuel	IGSCC, fatigue, IASCC, thermal embrittlement	Loss of fuel geometry	Visual[a]
9.	Baffle plate access hole covers	Residual stress, corrosive water, temperature	IGSCC	Improper core flow	Visual[a]
10	Steam separator/ dryer bolts	Corrosive steam, flow induced vibration, temperature, preload	IGSCC, fatigue, thermal embrittlement	Damage to steam lines lines and turbines	Visual[a]

a. Accessible surfaces and welds of vessel attachments.

currently thought to be the overall life-limiting mechanism. As with CRDMs, prompt initiation of HWC could be very beneficial in reducing IGSCC. The other primary mechanisms of concern are IASCC and fatigue.

Conclusions and recommendations for reactor internals are as follows:

1. Attachment welds of the reactor internals to the reactor vessel may contain sensitized material, and IGSCC cracks may propagate from the weld heat-affected zone into the pressure vessel base metal. These welds are generally difficult to inspect. Remote inspection tools for these sites should be developed.

2. IGSCC is the major degradation mechanism for the reactor internals. Sensitized, creviced, and cold-worked material is especially susceptible to IGSCC. IGSCC increases significantly when the coolant conductivity increases above 0.25 μS/cm.

3. IASCC is a potential degradation mechanism for components subjected to high fluence, such as the top guide. The threshold for IASCC damage is about 5×10^{21}nvt. A better understanding is needed to evaluate the damage associated with IASCC.

4. Hydrogen water chemistry (HWC) is a potentially effective mitigation method for IGSCC damage. HWC significantly reduces the level of oxygen in the BWR coolant and thus mitigates IGSCC damage. However, HWC remains to be proven in the field as an effective mitigation method for IASCC. The long-term effects, and possible side effects, of HWC also need to be evaluated.

5. The feedwater spargers and jet pumps are susceptible to high-cycle fatigue damage. For these stainless steel components, fatigue-crack initiation and growth-rate data in a HWC environment are needed.

6. Research should continue on the thermal embrittlement of the ferrite phase of cast stainless steel components, and on irradiation embrittlement of components in high flux areas. The possibility of thermal embrittlement of the ferrite phase and irradiation embrittlement of the austenitic phase of cast stainless steels should be investigated.

15.11 Countermeasures For Cracking In Boiling Water Reactor Recirculation Piping

The BWR recirculation piping has experienced considerable degradation caused by IGSCC, including through-wall cracking, in the recirculation piping. The IGSCC failures of the recirculation piping have been addressed by a number of industry- and NRC-sponsored programs, and a variety of countermeasures have been developed, which are listed in Table 15.16. Countermeasures for mitigating the other degradation mechanisms active in BWR recirculation piping are also listed in Table 15.16. Countermeasures for repair and replacement of degraded recirculation piping are also listed. However, long-term field-experience data are needed to assess the effectiveness of the various countermeasures. The conclusions and recommendations regarding the BWR recirculation pipe cracking are as follows:

1. Three stress improvement methods, heat sink welding, induction heating stress improvement, and mechanical stress improvement effectively mitigate IGSCC by introducing residual compressive stresses in the heat-affected zone on the inside surface of the recirculation piping.

2. The stress improvement methods introduce compressive stresses at the tip of shallow cracks in the heat-affected zone and are effective in inhibiting the growth of short cracks not exceeding 30% of the wall thickness. However, a higher inspection frequency and larger sample size are required for these welds.

3. Use of hydrogen water chemistry has been successful in suppressing IGSCC crack initiation, provided it is combined with very low levels of ionic impurities. Hydrogen water chemistry is effective when the level of dissolved oxygen is reduced below 20 ppb and the coolant conductivity is kept below 0.2 μS/cm. On-line monitoring of coolant chemistry and periodic IGSCC tests are recommended.

4. Short-term laboratory tests under simulated conditions show that the use of hydrogen water chemistry significantly increases the initial general corrosion rate of the carbon

Table 15.16. Summary of countermeasures for recirculation pipe cracking

Mechanism	Countermeasure	Mitigation	Repair	Replacement
IGSCC	Inductive heating stress improvement	X	X	X
	Heat sink welding		X	X
	Mechanical stress improvement	X	X	X
	Solution heat treatment			X
	Corrosion resistant cladding			X
	Nuclear grade material			X
	Hydrogen water chemistry	X		
	Weld overlay		X	
	Clamping device	X	X	
TGSCC	Hydrogen water chemistry	X		
	Minimize cold working in fabrication			X
Thermal embrittlement	Use of less susceptible material			X

steel components. However, once a corrosion film is formed, the general corrosion rate appears to be similar to the normal water chemistry corrosion rate. Long-term evaluation of the erosion-corrosion of carbon steel components subjected to hydrogen water chemistry is recommended.

5. Weld overlay introduces compressive stresses in the weldment and inhibits IGSCC crack initiation and growth. Analytical results indicate that weld overlays will inhibit the growth of cracks that do not extend beyond 60% of the wall thickness. The major barrier to extended use of weld overlays is the difficulty in performing reliable inspections of the weldment under the overlays. Improved ultrasonic methods have been developed for this purpose. All welds repaired by weld overlays should be inspected within each two refueling cycles.

6. Mechanical clamping devices introduce axial and circumferential compressive stresses in the piping and retard crack growth. In addition, such clamping devices provide an alternate load path around the degraded weldment and ensure its structural integrity.

7. Solution heat treatment of piping shop welds eliminates sensitization in the heat-affected zones and, thus, provides protection against IGSCC. This treatment is applicable to new

piping, and, at present, approximately 40% of the welds in the recirculation piping are solution heat treated.

8. Types 304NG and 316NG stainless steels are much more resistant to IGSCC and have been qualified as alternate materials for BWR piping. However, Type 316NG does not have the same weldability as Type 304 stainless steel, and it is susceptible to transgranular stress corrosion cracking (TGSCC). Laboratory results show that the use of hydrogen water chemistry and strict control of impurities in the coolant can mitigate TGSCC. Use of Type 347NG is currently being evaluated.

9. Application of corrosion-resistant cladding on the inside surface of the piping protects any sensitized surfaces from exposure to the BWR coolant, and has been successfully demonstrated. Corrosion resistant cladding may be applied to the new piping weldments in the shop or field.

15.12 Pressurized Water Reactor And Boiling Water Reactor Cables And Connections In Containment

The variety of cable system materials, constructions, installation conditions, potentially age-degrading stressors, and possible mechanisms of failure result in a complex array of situations to consider in assessing residual life. A realistic management of the aging process requires focusing on priority issues.

Those issues are as follows:

- Common-cause failures (CCFs), because they have the greatest potential impact on safety
- System component potential mechanisms of failure that have been revealed during qualification testing
- Mechanisms of failure that have been revealed during normal plant operation and relate to potential common-cause failures.

Table 15.17 is a summary of aging- and qualification-related cable system failure modes and contributing factors judged to be the most likely to impact the safety of some nuclear plants. All are aging related and are potential sources of CCFs following a design-basis accident or submersion event. Therefore, they are of technical concern when making any life assessment of in-containment Class 1E cable systems. Other failure modes may arise or their importance become known as research and experience accumulate.

These summary failure concerns and other factors discussed in the sections above form the basis for the following conclusions. First, conclusions are stated relevant to the technical status of life assessment factors; second, conclusions on life assessment strategies are presented.

15.12.1 Technical Conclusions

- The technical life assessment issues for in-containment cable systems are quite different from those of the balance of plant because of the potential for CCFs that can impact safety during or after design-basis accidents or submersion events and because of the inaccessibility of the containment after such events.
- Age-related changes that impact cable system susceptibility to CCFs are those that life assessment methodologies should target, whether or not those changes were considered in the original qualification program.
- Analytical or sampling/testing methodologies may be technically feasible for life assessment if the proper data and materials are available (see Section 13.8.2).
- There is generally insufficient containment ambient and hot-spot radiation and temperature data to assess the aging rates of cables or connections.
- In situ age-condition monitoring methods are presently inadequate for either cables or connections. Methodologies are being developed for cables, but the current work is not addressing connections.
- Data on measured age-condition parameters of cables or connections that were preaged for environmental qualification tests are

Table 15.17 Summary of potentially important failure modes and degradation factors for LWR containment cables and connections[a]

Failure Modes	Age Degradation Mechanisms	Dominant Aging Stressors	Components	Degradation Sites
Circuit ground or short when subject to condensing steam, spray or water (CCF)[b]	Jacket embrittlement and cracking—propagating through insulation. Bare insulation cracking.[c]	High temperature, O_2 presence, radiation in a few cases, sometimes moisture.	Single and multiconductor nonshielded jacketed cables. Kapton-exposed wires.	Hot spots, terminal areas at hot equipment, proximity to hot pipes, fire stops, exposed susceptible insulation.
Corrosion causes opens in, total loss of, or multiple grounds on shields (CCF, RF).	Jacket cracking or moisture diffuses through jacket and condenses.	Moisture, high temperature.	Shielded coaxial or multi-conductor paired cables.	Moist warm areas, high humidity; near water, steam leaks, or seepage.
Corrosion of contacts. Circuit opens, grounds, or shorts (CCF, RF).	Diffused moisture collects in cable and migrates into connection internals.	High temperature, moisture, and water contamination.	Connections not permanently sealed against cable internal moisture.	Moist warm areas, high humidity, near water, or steam leaks, or seepage
DBA pressure/steam/spray passes into or through connection. Contacts corrode or circuit grounds or shorts (CCF).	Polymer seals (O-rings) or cable polymers cold flow so that seals are not hermetic.[c]	High temperature and/or radiation dose, cable movements, vibration, thermal cycling.	Connections with compression seals.	Hot spots—thermal and radiation, connections where cable is moved.
Peak temperature and radiation during DBA cause excess leakage or losses to disable circuit function or lead to insulation breakdown (CCF).	Thermal and radiation aging leave remanent electrolytes to increase leakage or losses.	Heat, radiation, and moisture diffusion in normal service. Temperature, dose rate, and moisture after DBA.	Cables insulated with halogenated or filled polymers.	General—where exposed to harsh accident environments.
Same as above, except steam condensation and ionizing radiation are prime factors.	Gradual increases in surface contamination.[c]	Accumulations of wettable or conductive surface contamination.	Terminal strips.	Nonhermetic junction or terminal boxes with external or internal dust or contamination generators.
Excessive leakage disables MI cable circuit operation (CCF, RF).	Metal cold flow or loosened threads open hermetic seals to moisture intrusion.	Vibration, repeated movement, thermal cycling.	MI cable connections.	Connections subject to vibration or flexing.

a. The problems listed may have been anticipated and adequately addressed in the original Class 1E nuclear qualification program practices. However, they are ones that should be considered if qualification practices were not complete or rigorous in their application or if considering the extension of the original qualified life.

b. Notations in parentheses indicate potential for common-cause failures after a DBA or submersion (CCF) and for random failures during normal or abnormal service (RF).

c. The degraded condition noted is probably not electrically detectable when conditions are dry.

generally not available now but can be obtained in some cases. Such data will be an important basis for in situ age–condition monitoring programs as they are developed.

- Failure statistics or trends obtained from normal service are not as useful in life assessments of Class 1E containment cables as they may be for providing guidance to programs for reduction of time–random failures and improving plant availability.

- Failure analyses discussed in the LERs are usually inadequate for identifying either relevant critical aging stressors or the root cause mechanisms of polymer or cable failure.

- Many of the qualification issues that research and engineering or operating experience have brought to light since the writing of IEEE 323 and 383 in 1974 are aging related and should be considered in life assessment programs.

15.12.2 Strategy Conclusions

- An analytical approach to residual life assessment may demonstrate a qualified life well beyond the initially specified 40 years. That approach is applicable to cable systems with adequate nuclear qualification, including current preaging, type testing, and documentation. It would consist of a reanalysis of the original qualification preaging data, using conservatisms found between the specified and the actual operating (aging) environments and performance requirements.

- To maintain the current level of safety, life assessment programs based on reanalysis should address all new qualification issues that may directly affect the validity of predicting qualified life from the original preaging data. Those would include the ordering of sequential stresses, synergistic effects, dose rate effects, and oxygen diffusion effects.

- Other approaches to life assessment (or backup validation for the analytical approach) include removal of small samples for laboratory test and analysis, obtaining virgin components or removal of sufficient components from the plant for accelerated preaging and type–test (requalification), or use of in situ monitoring techniques under development as they become available.

- During any life assessment program, consideration should be given to the plant–specific potential impact of other qualification issues that may not have been addressed in the original qualification program but are now revealed as possible sources of common cause failures. Examples include excessive leakage currents under the peak temperature and radiation after an accident; wet cable internals affecting connections or connected equipment; long–term moisture aging effects on insulation; polymer relaxation (creep) compromising any compression seals used; and loss of or multiple grounds on instrumentation cable shields before or during an accident.

15.12.3 Recommendations. Based upon this study, the following are recommendations for immediate implementation by utilities:

- Immediate steps should be taken by the utilities to monitor containment temperatures and radiation levels and locate and monitor cable system hot spots

- Utilities should establish improved failure analysis and record keeping for all plant cables of the types used in Class 1E service

- Utilities should combine their efforts to obtain component samples for testing and to obtain baseline data on components preaged for design basis event (DBE) tests

- Periodic inspection programs should include careful examinations of connection areas to detect jacket cracking, disrupted or loose seals, signs of corrosion or moisture seepage, and surface contamination of electrical leakage surfaces

- During maintenance activities, disturbance of cable systems should be minimized when moving or disconnecting other equipment. Visual surveillance, temperature and radiation monitoring, and the cleaning of contaminated electrical leakage surfaces at terminals are the only routine activities generally recommended for cable systems to ensure their maximum life.

Recommendations for utility–, DOE–, and USNRC–sponsored research to improve the industry's ability to address life assessment of nuclear cable systems include the following:

- Continue support of projects on promising cable system age or condition monitoring methodologies for both laboratory and in situ uses

- Investigate the sensitivity of existing connections to (a) water migration from connected cable internals, (b) water ingress from polymer pressure seal relaxation/creep, and (c) water ingress from untested combinations of interfacing cable and connection materials with potential incompatibility

- Determine the influence of moist or wet normal aging exposure on the sensitivity of cable or other components to moisture degradation during DBAs

- Determine if a commercially feasible means exists for gathering formerly unreported qualification type test failure data in order to reveal any failure modes with impact on potential common-cause failures.

15.13 Pressurized Water Reactor and Boiling Water Reactor Emergency Diesel Generators

Emergency diesel generating units are a crucial component in every nuclear plant's emergency safety system. As such, they must operate reliably under adverse emergency conditions. But as complex systems, emergency diesel generators (EDGs) are inherently subjected to a number of operational and environmental stressors, which are aggravated by the emergency and testing demands placed upon them. Some of those test demands accelerate wear and aging and may decrease life expectancy.

The mitigation of a few key stressors and careful maintenance of a few primary degradation sites would greatly enhance EDG reliability and longevity, and consequently reduce risks in nuclear plant operations. Attention needs to be given to the stressors of fast starts and loadings, vibration, fatigue, heat, and corrosion, particularly corrosion in the air-start components. Likewise, surveillance and maintenance attention must be focussed on governors, turbochargers, on-engine fuel oil components, the air-start system (from compressor to admittance valves), and to the myriad controls and instruments—especially those involved in the ESFAS starting and loading systems and procedures.

Tables 15.18 and 15.19 summarize the information on the principal degradation processes developed in the various NPAR and other research studies, and examined in this chapter. Table 15.18 presents information on processes related to the structural/mechanical systems; Table 15.19 presents those related to electrical systems, instruments, and controls.

The authors have developed the following primary conclusions and recommendations, identified from the foregoing compendium of EDG aging studies and papers, and from the various references.

15.13.1 Conclusions

1. Although EDGs operate relatively few hours per year, and generally they start no more often in their lives (on average) than comparable engine-generators in nonnuclear service, they give evidence of more problems and functional failures than do their cousins in other utility service.

2. Some of this evidence is due to the rigid recording and reporting requirements of the nuclear industry; that is, even minor problems are reported as failures, which in other service would go largely unnoticed and accorded little import.

3. Nonetheless, a significant portion of EDG failures are real and threaten their critical mission as the last line of defense in event of power outages in the nuclear generating plants.

4. There are myriad systems and components that can fail, because these EDG units are complex and amount to complete generating plants in themselves. EDG units/systems as a whole experience failures to start and/or run of about one to five percent of the attempts—both real demands and operational tests.

5. Although failures of most individual items are quite infrequent, there are some key components that exhibit greater inclination for problems or failures:

    a. Governors

    b. Fuel oil injector pumps, nozzles, and high-pressure piping

Table 15.18. Summary of major degradation processes: EDGs – structural/mechanical systems

Rank[a] (System)	System[a]	Degradation Site[b]	Key Stressors	Degradation Mechanisms	Failure Modes
1.	Fuel system	Piping on engine[c]	Vibration; internal pressure; pressure pulsations	Metal fatigue; overstress – Sometimes caused by poor manufacturing or maintenance errors	Start or run modes. Fracture, leakage (sometimes resulting in fire)
		FO injection pumps	Adverse internal conditions	Binding of plunger (the results of physical scoring or varnishing) – Caused by poor manufacturing, maintenance errors, deterioration of oil (chemical change, bio–fouling, particles in oil)	Start or run modes. Failure to deliver oil or inadequate pressure and quantity – Reduces engine capacity and unbalances loads among cylinders
		FO injectors and nozzles	Adverse internal conditions	Binding of parts; plugging of nozzle holes – Same causes as above	Start or run modes. Same consequences as above
		FO supply pumps	Overstress; metal/metal contact	Metal fatigue; overstress; wear – Usually caused by misalignment and maintenance errors	Run mode. Fracture of drive shaft or coupling; loss of pressure, reduction in flow
		Strainers and filters	Contaminants in FO	Plugging of media, (particles in oil, biofouling, deterioration); – Usually caused by poor maintenance	Run mode (usually). Loss of oil flow, stopping engine
2.	Starting system	Starting air valve	Contaminants in compressed air (water, dirt)	Corrosion; plugging (by corrosion products, dirt); binding – Partially caused by poor maintenance, poor design of plant	Start mode. Failure to start. May also lead to combustion gases in air system (see text)

Table 15.18. (continued)

Rank[a] (System)	System[a]	Degradation Site[b]	Key Stressors	Degradation Mechanisms	Failure Modes
		Actuators/controls	Moisture in air; water hammer	Corrosion; plugging binding; water hammer (see text); – Partially caused by poor design and manufacturing and maintenance	Start mode. Failure to start; air leaks; fracture on damage from water hammer
		Starting motors	Contaminants in compressed air (water, dirt)	Corrosion; binding – Partially caused by poor design and maintenance	Start mode. Failure to start
3.	Cooling system	Pumps	Cavitation; metal/metal contact; contaminants; poor water chemistry	Erosion (the result of cavitation and particles); wear; corrosion – Partially caused by misalignment and poor maintenance, and to poor design (low NPSH)	Run mode. Loss of pressure and flow (erosion and corrosion of impeller and wear rings); leakage (at seals)
		Piping	Vibration; heat (if exposed piping); poor water chemistry; cavitation; unvented air	Damage to fittings, valves and controls; deterioration of gaskets, hoses, flex joints – Partially caused by poor design, maintenance	Run mode. Leakage; poor pump operation, air may cause hot spots in cylinder heads
		Heat exchangers	Cavitation; contaminants (dirt); stray electric currents/galvanic corrosion	Erosion of baffles, tubes; corrosion of tubes and tube sheets – Partially caused by poor design and manufacturing	Run mode. Leakage (usually internally); loss of capacity
		Radiator	Inadequate air flow; freezing; chemical attack	Plugging of fins; overstress tubes; corrosion	Run mode. Loss of capacity; leakage

Table 15.18. (continued)

Rank[a] (System)	System[a]	Degradation Site[b]	Key Stressors	Degradation Mechanisms	Failure Modes
4.	Engine structure	Crankcase and cylinder block	Dynamic stress; thermal stress	Dynamic and thermal fatigue; uneven expansion of abutting parts – Partially cuased by fast loading and poor manufacturing	Run mode. Cracked block/ crankcase; water leakage (usually into LO; ruined bearings and shaft)
		Liners and seals	Metal/metal contact with pistons; heat; chemical attack	Wear/scuffing; hotspots (caused by water scale); deterioration of seals – Partially caused by fast loading and lack of LO	Run mode. Piston seizure; crankcase explosion; leakage to LO: degradation of liner (heat)
		Main bearings	Loss of LO film; cavitation; heat; overstress	Wear; erosion/cavitation; wiping; fatigue cracking – Partly caused by fast starts; poor LO pressure; misalignment; poor maintenance	Run mode. Bearing fracture; loss of bearing capability; damage to crankshaft
		Cylinder heads	Overstress; heat	Overstress; dynamic and thermal fatigue; hot spots – Partly caused by poor design and manufacturing; fast starts	Run mode. Fracture/cracking; water leaks (usually into cylinder, leading to other problems)
		Bolting (all)	Vibration; overstress; dynamic stress	Fatigue; overstress – Partially caused by poor design	Run mode. Elongation; fracture (with other consequences)
5.	Intake and exhaust system	Turbocharger[c]	Vibration; heat; corrosion; overstress; surge	Bearing failure; loss of vanes and blades; fatigue fracture, IGSCC – Partly caused by fast starts and loading, poor LO flow, poor design and manufacturing	Run mode. Bearing loss and rotor seizure; loss of capacity; water leakage; fracture

Table 15.18. (continued)

Rank[a] (System)	System[a]	Degradation Site[b]	Key Stressors	Degradation Mechanisms	Failure Modes
6.	Lubrication system	Pumps	Overstress; cavitation; pressure pulses	Overstress; fatigue; erosion	**Run mode.** Fracture; loss of capacity
		Heat exchangers	Cavitation; electric currents/galvanic corrosion	Erosion and corrosion of tubes and baffles, poor manufacturing	**Run mode.** Leakage (internal)
		Lube oil	Contamination; heat	Sludge and foam; chemical deterioration - usually caused by jacketwater leaks	**Run mode.** Viscosity changes; sludge; loss of oil film
		Piping	Vibration; pulsations	Damage to fittings and devices; fatigue – Usually caused by poor design	**Run mode.** Fracture (fittings, devices, flex joints, hangers)
		Filters	Overstress; contamination	Plugging; fatigue (from pressure pulses)	**Run mode.** Loss of LO flow; fracture
7.	Drive train	Pistons and rings	Dynamic stress; thermal stress; metal/metal contact with liners	Overstress; fatigue; wear/scuffing – Partly caused by fast starts, poor design and manufacturing	**Start and run modes.** Broken rings; piston seizure; scuffing; fracture; burned piston crown; explosion
		Connecting rods	Overstress; dynamic stress	Stress failure; fatigue (especially in bolting areas) – Partly caused by poor design and fast starts and loading	**Run mode.** Fracture; piston seizure; crankcase explosion

Table 15.18. (continued)

Rank[a] (System)	System[a]	Degradation Site[b]	Key Stressors	Degradation Mechanisms	Failure Modes
		Crankshaft	Dynamic stress; torsional vibrations; bad bearings	Overstress; unbalanced loads; fatigue – Partly caused by poor design, misalignment, bearing failure, operation at critical speeds	Run mode. Fracture; crankcase explosion

NOTES:
FO = fuel oil
LO = lubricating oil

a. From Table 14.1 and 14.2 and Reference 2.

b. From Tables 14.3 and 14.4

c. Piping on engine and turbocharger rank as first and second highest individual degradation sites, respectively.

Table 15.19. Summary of major degradation processes: EDGs – electrical systems: instruments and controls

Rank[a] (System)	System[a]	Degradation Site[b]	Key Stressors	Degradation Mechanisms	Failure Modes (mode in which occurring)
1.	Instruments and controls	Governor	Vibration; torsional vibration; heat; oil contamination	Maladjustment; wear; fatigue; Viscosity change; oil deterioration – Partly caused by misapplication, poor maintenance, fast starts	Loss of effective governing control; drift; fracture of components; (start and run modes)
		Sensors and relays	Vibration; dust, humidity, chemical attack; heat	Maladjustment and drift; loss of electrical contact; corrosion; overheating, arcing dust; erosion – Partly caused by misapplication	Interruption of function (start and run modes)
		Control air system	Vibration; moisture, dust	Maladjustment, plugging	Interruption of function (start and run modes)
		Alarms and shutdowns	Vibration; moisture	Maladjustment; fatigue; corrosion	Interruption of function (start and run modes)
2.	Generator components	Voltage regulator	Heat; vibration	Loss of function, broken contacts; – Partly caused by poor manufacturing, maintenance	Interruption of function (start and run modes)
		Generator	Torsional vibrations; overstress; electrical grounding and voltage excursions; dust	Fatigue; overstress; insulation failure	Fracture; loss of distortion of coils, grounding [run mode (usually)
		Exciter	Dust; humidity; vibration (static types)	Wear; arcing	Loss of function (run mode)

Table 15.19. (continued)

Rank[a] (System)	System[a]	Degradation Site[b]	Key Stressors	Degradation Mechanisms	Failure Modes
3.	Switchgear	Relays	Dust; humidity	Corrosion; loss of electrical contact	Interruption of function [run mode (usually)]
		Circuit breakers	Arcing (usually on break); humidity	Corrosion; maladjustment	Interruption of function; explosion/fire (start/stop mode)

a. From Tables 14.1 and 14.2 and Reference 2.

b. From Tables 14.3 and 14.4.

c. Turbochargers

d. Starting air admittance valves, distributors, and piping

e. Instruments and controls, particularly those controlling starting and loading.

6. Of all the failures, some 50 to 60% are attributable to aging and wear; others are attributable to malfunctions obviously related to other causative factors.

7. There are numerous stressors affecting EDG component viability; key among them are

   a. Adverse operating conditions—vibration, excessive loads, fatigue, corrosion, and poor lubrication

   b. Poor quality starting air

   c. Poor design and manufacturing quality

   d. Adverse environmental conditions—dust, humidity, heat

   e. Poor maintenance and operation

   f. Deterioration of working fluids

8. The regimen of fast-starting/fast-loading imposes several burdens on EDGs not normally encountered in nonnuclear utility service and appears to both demarc and explain why EDG service results in more failures, per hour of use or number of starts than does other service.

9. Other adverse conditions of EDG service include

   a. The extent and complexity of the EDG control systems

   b. Limited hands-on monitoring and mothering of EDG units in operation, a freedom available to and inherently used at nonnuclear plants

   c. Lack of ongoing operational experience by EDG operators and maintenance personnel; such experience gives most nonnuclear operators greater awareness of operational conditions and incipient or developing problems.

10. EDG unreliability and failures will not be significantly reduced until the key factors listed in 7, 8, and 9 above are effectively addressed and mitigated. However, it is the conclusion of most investigators that, to a great extent, such can be achieved by judicious changes in operational and maintenance regulations and practices.

11. One general thrust relates to development and application of appropriate maintenance programs geared toward anticipating and mitigating known key stressors and their consequences at recognized degradation sites. This involves monitoring and trending operating parameters and the performance of reliability-centered preventive maintenance before events occur.

12. Maintenance programs also must involve heightened and ongoing training for operational and maintenance personnel, and greater management appreciation of the need—and benefits—of such programs.

13. Possibly the greatest gain will come, however, from a change in the NRC's fast-start/fast-load requirements.

    a. A shift of rather minor proportions in acceleration to synchronous speed should reduce appreciably the problems engendered by physical stresses and inadequate prelubrication.

    b. Elimination of, or a significant reduction in, fast-start testing, shifting instead to a program of more measured starting and extended operation, accompanied by monitoring, trending, and evaluation of key operating parameters, will eliminate many stressors and actually be more revealing of incipient problems.

    c. Additional analysis and evaluation would likely show that very fast starting and loading of EDGs is not required for most (or maybe all) loss-of-power-and-coolant accidents.

15.13.2 Recommendations

1. Applicable regulations, standards, and plant safety specifications should be altered to

minimize fast–start/fast–load EDG requirements.

2. Surveillance and testing concepts, and the whole context of operations, should be modified to enhance awareness of the capability and condition of the unit. An active trend-analysis program should be an intimate part of normative plant operations and surveillance and testing.

3. Maintenance precepts should be reliability-centered; preventive and predictive; proactive rather than reactive; and accompanied by enhanced training of maintenance and operational personnel. Inspection tear-down and overhaul should be avoided except as clearly needed.

4. Future research should be focused on troublesome components and dominant failure modes, in cooperation with manufacturers, to identify specific weaknesses and stressors, and to develop pertinent solutions and changes in operations, surveillance, and maintenance so as to anticipate and mitigate effects.

   a. Governors – devising changes in governor internals and/or governor application (mounting, shielding, cooling, etc.) so as to reduce their sensitivity to vibration, torsional vibrations, oil heating, inadequate venting, and other stressors, determined to be deleterious by research and field evaluation

   b. Fuel system components, like injectors, injector pumps, and high–pressure tubing—devising methods to reduce sensitivity to vibrations and pressure pulsations, to adverse oil conditions

   c. Turbochargers – to enable all turbos to accept prelubrication, to cool bearings in better ways, to enhance integrity of blades and vanes

   d. Starting and loading controls – to make these more reliable and less susceptible to dust and moisture and other containments, and to vibrations, in order to improve their longevity under repeated operations.

5. EDG units should be lubricated before startup whenever possible. Equipment on units that cannot presently accommodate prelubrication should be modified.

6. The starting air supply should be kept clean and dry.

7. EDG units should be operated more regularly, for longer periods, to increase operator familiarity with unit operations, to increase monitoring, surveillance, and parameter trending, and to use fuel before it can deteriorate.

8. Provision should be made to ensure ability to manually start each unit in cases of plant blackout.

9. Diagnostic equipment and techniques should be developed to allow testing of pertinent controls and systems related to design–basis event starting programs.

10. The aging of fuel oil and lubricating oil in standby service should be studied, and effective mitigation techniques developed.

11. Owner/operator interface with manufacturers and service departments should be increased; and schooling programs should be instituted and maintained for operators and other relevant personnel.

12. Owner participation in plant design review and equipment validation processes should be enhanced for future EDG facilities.

APPENDIX A

SUMMARY OF THE EPRI RESEARCH AND DEVELOPMENT PROGRAMS TO ASSESS THE RESIDUAL LIFE OF LIGHT WATER REACTOR COMPONENTS

APPENDIX A

SUMMARY OF THE EPRI RESEARCH AND DEVELOPMENT PROGRAMS TO ASSESS THE RESIDUAL LIFE OF LIGHT WATER REACTOR COMPONENTS

Introduction

Since its inception in 1974, the Electric Power Research Institute (EPRI) has managed approximately $0.7 billion of programs in support of U.S. owners of nuclear generation units. EPRI's R&D efforts cover a broad spectrum of interests ranging from specification of advanced systems through to support of day–to–day operations.

About 20–25% annually has been devoted to those remedial and preventative action projects that are a major technical resource base for Residual Life Assessment of major light water reactor components. In order to provide readers of this report with the comprehensive perspective, the report sponsor (USNRC) has provided EPRI the opportunity of summarizing its residual life assessment activities in this appendix. What follows is a summary of the applicable EPRI sponsored research, as well as detail on some of the major projects.

Overview

EPRI programs are planned and implemented on a 3 to 5 year cycle in coordination with a utility advisory structure. The basis of action is a "Strategic Program Element" (SPE); a broad description of an industry objective believed to require resolution via research and development. Both current and completed SPEs are pertinent to residual life assessment.

The current SPEs that apply are noted in Table 1 together with brief descriptions of their essential content. One group relates to the resolution of recognized operations limiting deteriorations, such as corrosion effects in BWR piping or in PWR steam generators. A second, focused by plant life extension (PLEX) activities, aims at pre–operational recognition and avoidance of those substantive deteriorations that may not have been correctly considered in design or which arose because of operational changes. Figure 1 illustrates this separation and the general approach used for the residual life assessment efforts.

Table 1

Strategic program elements pertinent to residual life assessment (1988)

SPE	Title / Brief Description[a]
8	Radioactive Waste Management
	High–level Waste, Technical R&D and Safety Assessment Spent Fuel Behavior Under Storage Conditions Decommissioning, Intermediate and Low Level Wastes Disposal
20	Nuclear Seismic Risk
	Seismic Design Ground Motion Re–evaluation for Earthquakes to Quantify Seismic Margins Substation Seismic Performance Severe Accident Containment Integrity Concrete Seismic Performance Storage Tank Integrity Assessment Under Seismic Loading

Table 1 (continued)

SPE	Title / Brief Description[a]
21	Light Water Reactor Safety
	Water Hammer Prevention, Mitigation and Accommodation
	PWR Pump Analysis and Testing
	Component Reliability Data Compilation, Analysis, and Software
	Expert System for Operations Decision–Making
	Computer–Aided Monitoring and Surveillance of LWR Technical Specifications
	Power Plant Computer Communications Technology
22	Nuclear Component Reliability
	Nozzle and Pipe Inspection Technology
	Near Surface Underclad Crack Detection
	Long–Term Inspection Requirements
	Inspection of Welds Beneath Coatings
	Reliability of Piping and Fittings
	Fatigue Monitoring on Plant Components
	Material Property Variability
	Codes, Standards, and Technology Transfer
23	Nuclear Plant Corrosion Control
	Corrosion Fatigue Characterization of RPV Steels
	Evaluation of Corrosion–Assisted Crack Growth in Nuclear Power Plant Components
	Mechanisms of Stress Corrosion Cracking
	Corrosion of Service Water Systems
	Hydrogen Water Chemistry – Mitigation of Irradiation Assisted SCC in Core Components
	Long–Term Effects of Hydrogen Water Chemistry
24	Nuclear Plant Operations & Maintenance
	Maintenance Optimization
	Guidelines for Application of Computer Assisted Instruction
	Guidelines for Surveillance Testing of Standby Equipment
	Data Consolidation for Research Project Planning
	Component Life–Cycle Advisor
26	Nuclear Plant Constructibility
	Guidelines for Applying Computer Aided Design Systems to Generating Plant Projects
	Nuclear Construction Issues Research
	Field certification of Materials for Operating Station Modifications
27	Nuclear Plant Life Extension
	LWR Life Extension
	Component Aging and Qualification
29	Advanced Nuclear Systems

Table 1 (continued)

SPE	Title / Brief Description[a]
43	Steam Generator Reliability
77	Occupational Radiation Control
	Qualification of Alternate Materials for Cobalt Alloys Passivation and Surface Conditioning Decontamination Process Development and Demonstration Plant Decontamination Demonstration Coolant Monitoring Techniques

a. Titles shown are 1988 descriptors, completed work not always indicated. Further detail available in EPRI "Research and Development Plan 1988–90," January 1988.

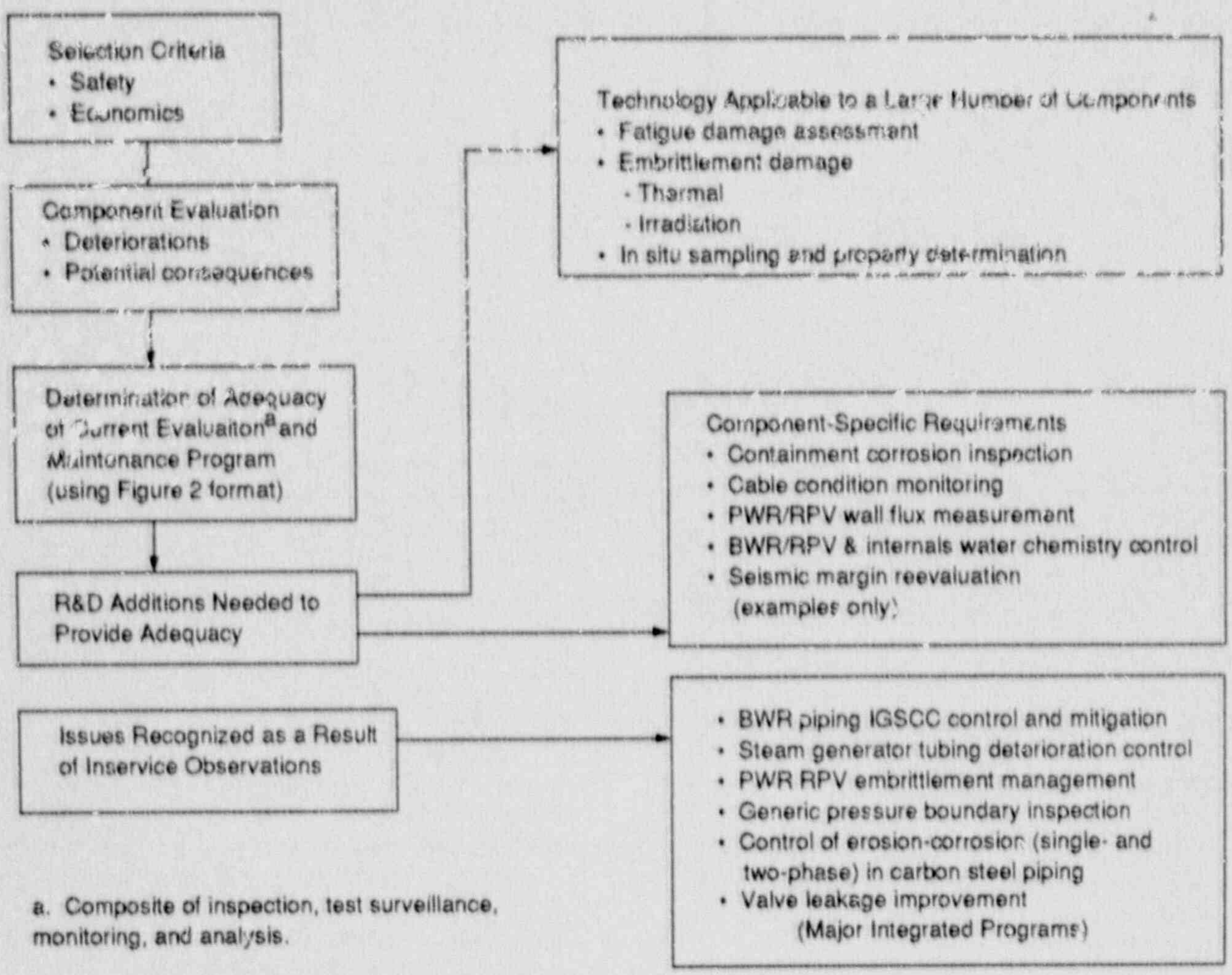

Figure 1. Scope of EPRI residual life and deterioration management programs.

Figure 2 illustrates a formalized decision process for evaluating the effect of design basis changes on remaining life that is utilized in the PLEX–oriented work. Some modification is required for those components whose lifetime is defined by a qualification test. However, this derivative of ASME Boiler Code efforts is a residual life assessment format that considers deterioration, consequences and owner refurbishment options in a format appropriate for both management and regulatory review. Figure 3 suggests the correlation and differences in objectives of these two parties.

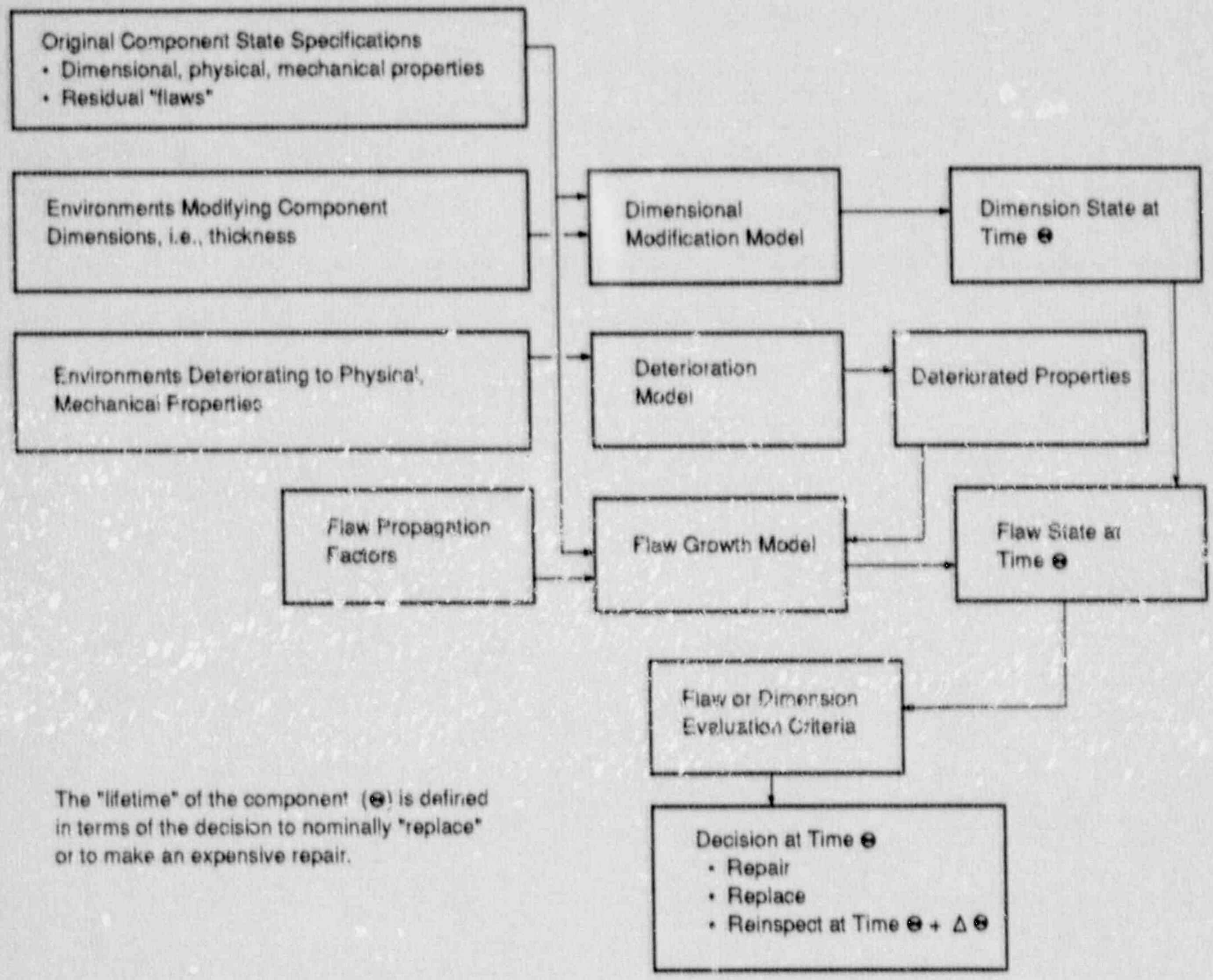

Figure 2. Procedure for evaluating component longevity.

Project Summaries

Table 2 summarizes the INEL topics covered to date in their work for the USNRC and indicates how they align with EPRI SPEs and with subsequently presented summaries.

Tables 3 through 18 provide concise relevant summaries of EPRI work correlated with the INEL topics. Both scope and time scale information are provided together with pertinent references. Exceptions are made where EPRI addresses an issue common to many components as a "technology." In these cases, the summary addresses the technology and, in a subheading indicates the INEL topics to which it applies. The EPRI project summary tables are also correlated to the NUREG topics in Table 2.

Table 19 is a comprehensive listing of EPRI publications pertinent to residual life assessment in the

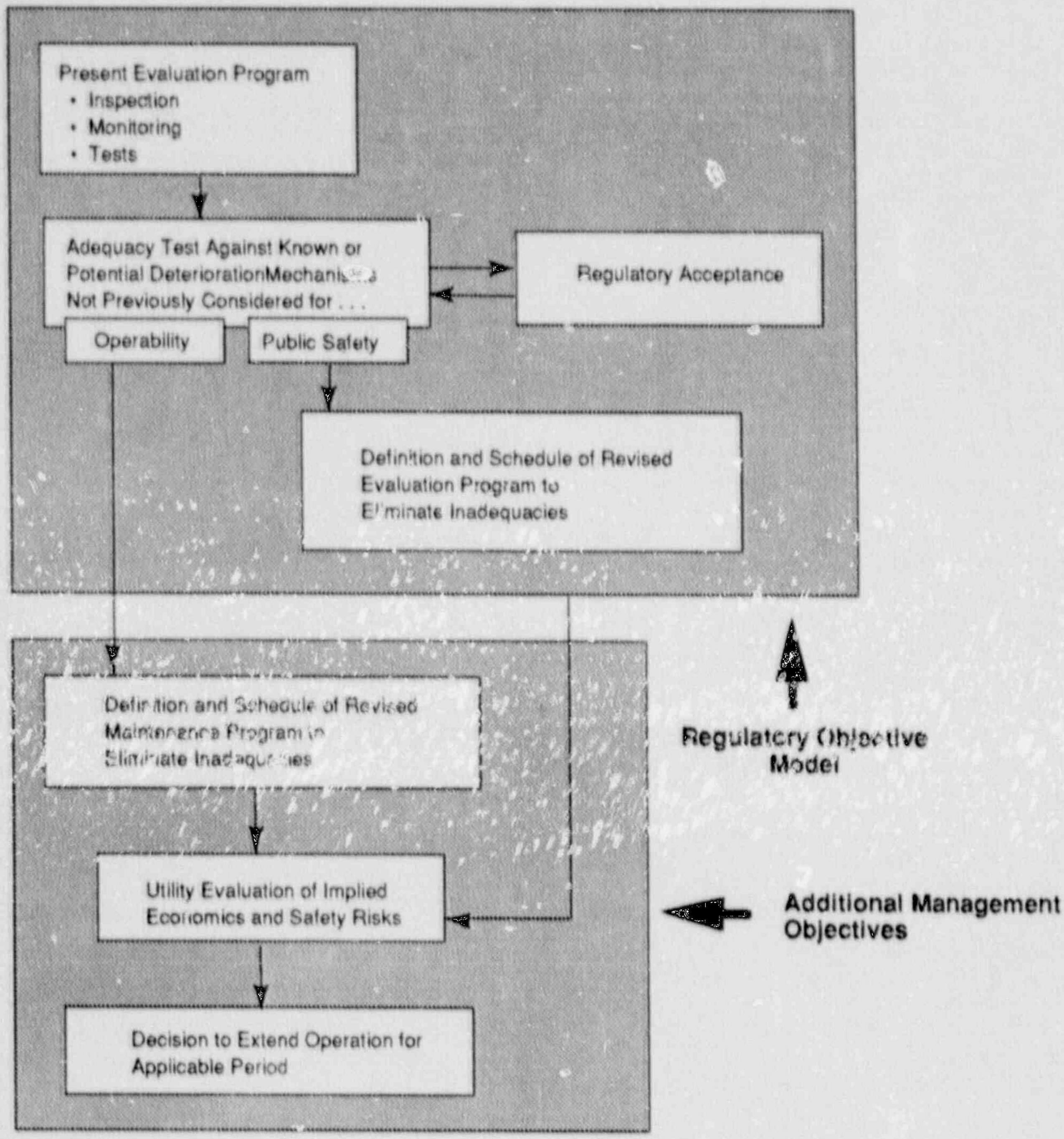

Figure 3. Regulatory and management RLA models and their interactions.

context of PLEX. References 4 and 15–17 from this table are collective evaluations, which, in combination, provide assessments for all of the topics covered in NUREG/CR–4731 to date. They are therefore, comprehensive source materials of similar nature.

Overall Comparison of INEL And EPRI Assessments

The INEL work performed for the USNRC to date is identified as a source book intended for future development of a residual life assessment of those components important to assuring the continued safe operation of commercial LWRs. It is excellent for this purpose, particularly with respect to priority of components selected and comprehensive identification of potential inadequacies in their design evaluation. EPRI programs reflect virtually the identical interests. Further comparisons are inappropriate until the source information is converted to a residual life assessment document, specifically by considering those criteria and evaluations noted in Figure 2 that are necessary to evaluate the safety consequences of a deterioration.

Availability of EPRI Reports

All documents referenced in this appendix are available through the EPRI Research Reports Center at no cost to EPRI member utilities. Nonmembers and the general public can purchase most of these reports at predetermined costs that reflect the cost of their development. Abstracts of any report are available through on-line data retrieval services through EPRI or other commercial services, such as Dialog.

Table 2

Alignment of EPRI RLA Programs with NUREG/CR-4731 Topics

NUREG/CR-4731 TOPIC	EPRI SPE		EPRI Project Summary Table
Volume 1			
PWR			
PRESSURE VESSELS	**22**	27,20	3
CONTAINMENT & BASEMATS	**27**	21,24	4
COOLANT PIPING	**22**	21	18
STEAM GENERATORS	**43**		5
VESSEL SUPPORTS	**27**	22	6
BWR			
PRESSURE VESSELS	**22**	22	7
RECIRCULATION PIPING	**23**	27	8
VESSEL SUPPORTS	**27**	22	6
NDE METHODS	**22,27**	23,24	9
ADEQUACY OF ASME CODE ISI TECHNOLOGY	**22,27**	23,24	9
CURRENT LIFE ASSESSMENT TECHNIQUES	**22,27**	23,24	9
NEW OR EMERGING METHODS FOR INSPECTION & LIFE ASSESSMENT	**22,27**	23,24	9
Volume 2			
LWR			
COOLANT PUMPS	**27**	24	10,18
PWR			
PRESSURIZER	**27**	22	17
PRESSURIZER SURGE & SPRAY LINE NOZZLES	**27**	22	17
REACTOR COOLANT SYSTEM CHARGING & SAFETY INJECTION NOZZLES	**22**	17	
FEEDWATER PIPING & NOZZLES	**24**	22	17
CONTROL ROD DRIVE MECHANISMS & REACTOR INTERNALS	**22,24**	27	12,18
STEAM GENERATOR TUBING COUNTERMEASURE	**43**		5
CABLING	**27**		13
EMERGENCY DIESEL GENERATORS	**21**	24	14
BWR			
CONTAINMENTS	**27**	21,24	15
FEEDWATER AND MAIN STEAMLINE PIPING	**24**	21	17
CONTROL ROD DRIVE MECHANISMS	**24**		12,18
REACTOR INTERNALS	**23**	27	16
RECIRCULATION PIPING COUNTERMEASURES	**23**	22	8
CABLING	**27**		13
EMERGENCY DIESEL GENERATOR	**21**	24	14
GENERIC SUBJECTS			
FATIGUE	**21,22,27**		17
THERMAL EMBRITTLEMENT OF CAST AUSTENITICS	**22,27**		18

Note: Bold number indicate primary SPE

Detailed Project

Summaries

Table 3

TITLE: Management of Reactor Vessel Irradiation Embrittlement

SPE: 22, 27

PERIOD: 1974–1989

GENERAL OBJECTIVE: The objective is to develop a unified industry approach for dealing with embrittlement issues, and to define remedial measures and guidelines for mitigating embrittlement of reactor pressure vessels.

SCOPE: PWR reactor vessel longevity limitations caused by irradiation embrittlement are well known. Evaluation requires extensive knowledge and development in inspection, flaw evaluation, fracture mechanics methodology, materials property measurement, fluence monitoring, damage assessment and correlation and physical sampling. Assessment of mitigation or damage recovery methods, such as fluence reduction and thermal annealing respectively, are also desirable. This comprehensive effort has been ongoing since 1974. Current efforts include establishing a common reactor vessel material database, coordinating the activities of various industry groups in developing an industry plan for resolving outstanding embrittlement issues and documentation of embrittlement management methods applicable to extended service of LWR units.

KEY REPORTS:

The following reports present comprehensive summaries of work for the period 1974–8:

1. *Pressure Boundary Technology Program: Progress 1974–1978*, EPRI NP–1103–SR, March 1979, and in updates under the title: *Nuclear Systems and Materials Department Research Program Plan*, EPRI NP–4514–SR–LD, March 1986.

The following is an overall summary of embrittlement management, which may be published in 1989:

2. *Reactor Vessel Embrittlement Management Program, Phase 1 Report*, Draft EPRI Report, December 1988.

The following is a more detailed bibliography by subject heading:

Reference Fracture Toughness

3. *Fracture Toughness Data for Ferritic Nuclear Pressure Vessel Materials*, EPRI NP–119, April 1976.

4. *HTGR Fracture Toughness Program*, EPRI NP–120, April 1976.

5. *Fracture Toughness Data for Ferritic Nuclear Pressure Vessel Materials*, EPRI NP–121, April 1976.

6. *Experimental and Statistical Requirements for Developing a Well–defined K_{IR} Curve*, EPRI NP–372, May 1977.

7. *Analysis of Radiation Embrittlement Reference Toughness Curves*, EPRI NP–1661, January 1981.

8. *An Approach for Predicting Reference Fracture Toughness in Irradiated Vessel Materials*, EPRI NP–5793, May 1988.

9. *Determining Fracture Properties of Reactor Vessel Forging Materials, Weldments, and Bolting Materials*, EPRI NP–122, July 1976.

10. *EPRI Ductible Fracture Research Review Document*, EPRI NP–701–SR, February 1978.

Table 3 (continued)

Ductible Fracture and Testing Methods

11. *Computational Modeling Microstructural Fracture Processes in A533B Pressure Vessel Steel*, EPRI NP-1398, May 1980.

12. *Methodology for Plastic Fracture*, EPRI NP-1735, March 1981.

13. *An Engineering Approach for Elastic-Plastic Fracture Analysis*, EPRI NP-1931, July 1981.

14. *High Temperature Elastic-Plastic and Creep Properties for SA[illegible] Grade B Class 1 and SA508 Materials*, EPRI NP-2763, December 1982.

15. *Reconstituted Charpy Impact Specimens*, EPRI NP-2759, December 1982.

16. *Advanced in Elastic-Plastic Fracture Analysis*, EPRI NP-3607, August 1984.

17. *Fracture Testing of Ductile Steels*, EPRI NP-5014, January 1987.

18. *Elastic-Plastic Fracture Analysis of Through-Wall and Surface Flaws in Cylinders*, EPRI NP-5596, January 1988.

Radiation Embrittlement Trend Curves

19. *Evaluation of Irradiation Response of Reactor Pressure Vessel Materials*, EPRI NP-2720, November 1982.

20. *Evaluation and Prediction of Neutron Embrittlement in Reactor Pressure Vessel Materials*, EPRI NP-2782, December 1982.

21. *Physically Based Regression Correlations of Embrittlement Data From Reactor Pressure Vessel Surveillance Program*, EPRI NP-3319, January 1984.

22. *Steady-State Radiation Embrittlement of Reactor Vessels*, Volume 2, EPRI NP-4224, September 1985.

23. *Simulated Void-Box-Capsule Charpy Impact Test Results*, EPRI NP-4630, NUREG/CR-3320-Volume 5, August 1986.

24. *Embrittlement of LWR Pressure Vessel Steels*, EPRI NP-6114, December 1988.

Reactor Vessel Materials Data and Data Bases

25. *Nuclear Pressure Vessel Steel Data Base*, EPRI NP-933, December 1978.

26. *Irradiated Nuclear Pressure Vessel Steel Data Base*, EPRI NP-2428, June 1982.

27. *Nuclear Plant Irradiated Steel Handbook*, EPRI NP-4797, September 1986.

Pressurized Thermal Shock

28. *Robinson 2 Reactor Vessel: Pressurized Thermal Shock Analysis for a Small-Break LOCA*, EPRI NP-3573-SR, August 1984.

29. *Calvert Cliffs 1 Reactor Vessel: Pressurized Thermal Shock Analysis for a Small Steam Line Break*, EPRI NP-3752-SR, November 1984.

30. *Fracture Evaluation of W Reactor During a PTS Transient*, EPRI NSAC-75, April 1985.

31. *Fracture Evaluation for a C-E Reactor During a PTS Transient*, EPRI NSAC-89, November 1985.

Dynamic Fracture Toughness and Crack Arrest

32. *An Assessment of Dynamics Fracture Mechanics for the Analysis of Crack Arrest in a Pressurized Thermal Shock Event*, EPRI NP-4043, May 1985.

33. *Tests and Analyses of Crack Arrest in Reactor Vessel Materials*, EPRI NP-5121M, April 1987.

34. *Calculation of Dynamic Crack Arrest in Reactor Vessel Materials*, EPRI NP-5121M, April 1987.

Reactor Vessel Thermal Annealing

35. *Development of a Generic Procedure for Thermal Annealing an Embrittled Reactor Vessel Using a Dry Annealing Method*, EPRI NP-2493, July 1982.

36. *Feasibility of and Methodology for Thermal Annealing an Embrittled Reactor Vessel*, Volume 2, EPRI NP-2712, November 1982.

37. *Thermal Annealing of an Embrittled Reactor Vessel, Feasibility and Methodology*, EPRI NP-6113M, January 1988.

Requalification and Vessel Integrity Analysis

38. *Rationale for a Standard on the Requalification of Nuclear Class 1 Pressure-Boundary Components*, EPRI NP-1921, October 1981.

39. *Procedure for the Assessment of the Integrity of Nuclear Pressure Vessels and Piping Containing Defects*, EPRI NP-2431, June 1982.

40. *Application of Probabilistics and Decision Analysis Methods to Structural Mechanics and Materials Sciences Problems*, EPRI NP-3613, August 1984.

41. *Status of Nuclear Class 1 Component Requalification*, EPRI NP-4889, December 1986.

42. *Evaluation of Reactor Vessel Beltline Integrity Following Unanticipated Operating Events*, EPRI NP-5151, April 1987.

Flux Reduction

43. *Investigating the Flux Reduction Option in Reactor Vessel Integrity*, EPRI NP-3110-SR, May 1983.

Residual Stresses and Cladding Effects

44. *The Influence of Residual Stresses on Small Through-Clad Cracks in Pressure Vessels*, EPRI NP-3638, July 1984.

In-Service Inspection of Reactor Pressure Vessels

45. *Development of an Ultrasonic Imaging System for the Inspection of Nuclear Reactor Pressure Vessels*, EPRI NP-1229, October 1979.

46. *Estimation of the Effect Detection Probability for Ultrasonic Tests on Thick Section Steel Weldments*, EPRI NP-991, February 1979.

47. *Nondestructive Examination Acceptance Standards ASME Section XI*, EPRI NP-1406-SR, May 1980.

48. *Technology Transfer Phase of Advanced Ultrasonic Nuclear Reactor Pressure Vessel Inspection System*, EPRI NP-1535, September 1980.

49. *Results of EDF/Framatome Under-Clad Crack Detection Methods*, EPRI NP-2841, January 1983.

50. *Signal Processing for Under-Clad Cracks*, EPRI NP-3558, July 1984.

51. *Clad Interface Crack Detection and Sizing*, EPRI NP-4033, May 1985.

52. *Evaluation of the Ultrasonic Data Recording and Processing System*, EPRI NP-4870-LD, October 1986.

53. *Evaluation of the Ultrasonic Data Recording and Processing System (UDRPS)*, EPRI NP-4397, January 1986.

Dosimetry

54. *Pressure Vessel Neutron Dosimetry of Three PWR's*, EPRI NP-5733, April 1988.

55. *Testing of the ENDF/B-V Nuclear Data Library on Thermal Benchmark Experiments*, NP-5058, February 1987.

Table 4

TITLE: PWR Containment and Basemats

SPE: 27

TIME PERIOD: 1985–1989

GENERAL OBJECTIVE: Provide guidelines and technology that insure the safety and structural integrity of PWR containments with respect to recognized and potential deterioration phenomena that may be encountered in long–term service.

SCOPE: Examinations of the susceptibility of both concrete and free–standing steel containments have been completed and related to the current inspection, surveillance, analysis and test programs utilized to validate their safety and structural integrity in service. Additions to these current efforts judged to be desirable for long–term service were identified and procedures developed for their implementation. Accent areas include: coating dequalification procedures, liner corrosion at visually inaccessible surfaces and exposure of concrete surfaces to working fluids and groundwaters containing aggressive ions.

KEY REPORTS:

1. *Technical Evaluation of the Longevity of PWR Containment Systems*, EPRI report in publication (1989).

2. *The Longevity of Nuclear Power Systems*, EPRI Report NP–4208, August 1985. This report contains an extensive section on concrete structures subsequently published in *Concrete Component Aging and Its Significance Relative to Life Extension of Nuclear Power Plants*, ORNL/TM–10059.

Table 5

TITLE: PWR Steam Generators

SPE: 43

TIME PERIOD: 1987–1992

GENERAL OBJECTIVE: The objective is to improve steam generator reliability by reducing forced outages and repairs and extending steam generator life.

SCOPE: The scope includes improving water chemistry control, steam generator design and operation, and in-service inspection. Guidelines for new steam generators and methods for predicting the thermal, hydraulic and vibration performance are being developed. Inspection methods are being evaluated and new tubing materials and fabrication methods assessed. Modeling the carryover and fall back in steam generators simulating steam line break events in PWRs to demonstrate safety margins for tube rupture is being conducted.

KEY REPORTS:

A comprehensive summary of all work conducted in the 1977–1983 timeframe is presented in the *Steam Generator Reference Book*, published by EPRI May 1985. Significant summaries of later work are as follows:

1. PWR Secondary Water Chemistry Guidelines, Rev. 2, EPRI NP-6239 December, 1988.

2. S. J. Green, "Thermal, Hydraulic, and Corrosion Aspects of PWR Steam Generator Problems," *Heat Transfer Engineering, 9, 1*, pp. 19–68, 1988.

3. *Modeling PWR Steam Separators During Transients*, EPRI NP-5272, August 1987.

4. *PWR Steam Generator Examination Guidelines, Revision 2*, EPRI NP-6201, December 1988.

Table 6

TITLE: Reactor Pressure Vessel Supports for LWRs

SPE: 22, 27

TIME PERIOD: 1984–1989

GENERAL OBJECTIVE: Development of evaluation guidelines for RPV supports that insure their safe operation throughout their license term and extended service.

SCOPE: Review of the potential failure modes for all types LWR supports identified low temperature neutron embrittlement (LTNE) with resulting loss of fracture toughness as a primary life limiting concern for some PWR design configurations. Early efforts were concerned with defining means for resolution in the context of USNRC Unresolved Safety Issue A-12. Contemporary work has focused on revised correlations of LTNE damage in terms of fluence and flux to produce guidelines for plant actions for the limited number of units that may be subject to operation limiting damage during extended service. This guideline has been completed. Fatigue and corrosion from leaks of water containing aggressive ions are addressed where appropriate. Supplementary work in field sample acquisition and test is in progress.

KEY REPORTS:

1. *Requirements and Guidelines for Evaluating Component Support Materials Under Unresolved Safety Issue A-12*, EPRI NP-3528, June 1984.

2. *Simulated Void Box Capsule Charpy Impact Test Results*, EPRI NP-4630, August 1986.

3. "Reactor Pressure Vessel Support Life Extension," in *UNPLEX Project Briefs*, EPRI NP-5388-SP, Rev. 1, Section 3.8, October 1988.

Table 7

TITLE: BWR Pressure Vessels

SPE: 22, 23, 27

TIME PERIOD: 1989–1993

GENERAL OBJECTIVE: The objective is to review known and possible deteriorations that may impact on the safety of the RPV for long–term service and develop technology that assures safe, long–term operation.

SCOPE: Three deteriorations of concern in increasing order of importance are: fatigue, neutron embrittlement, and stress corrosion. Current programs are considered adequate for all but the latter, whose primary impact is expected to be evidenced at vessel attachments and penetrations. Corrosion effects are not expected to affect the safety or integrity of the vessel due primarily to relatively low flaw propagation rates. However, to validate deterioration management methods, the BWR Owners Group and EPRI have defined an integrated industry program to begin in 1989, entitled "Control of Stress Corrosion Cracking in BWRs." This work will resolve indicated issues, address vessel inspection, and evaluation and mitigation techniques.

The five goals of this industry–wide program have been defined which address identified needs and contribute to the broad project objective of controlling costs and allaying safety concerns associated with corrosion damage in BWR NSSS components.

Goal 1: Reduce the likelihood of stress corrosion cracking for BWR internals and vessel attachment welds without adversely affecting the performance of other NSSS components.

Approach: a) Without degrading fuel cladding corrosion performance, adapt present HWC guidelines to protect many vessel internals as well as piping.

b) Improve the SCC resistance of existing components through the use of surface modification treatments.

Goal 2: Focus inspection efforts where they are most effective in confirming safety margins.

Approach: Determine the likelihood and the consequence of cracking in each component or weldment, and prioritize these in terms of the risk–reduction benefit of in–service inspection.

Goal 3: Assure the timely availability of inspection tools and techniques for required in–vessel inspections.

Approach: Facilitate the independent development of inspection technology by the commercial sector and verify the effectiveness of the resultant capability.

Goal 4: Avoid unnecessary repairs of defects or UT indications in BWR vessels and internals.

Approach: a) Develop technical support for reliable predictions of SSC behavior, and for assessments of the consequence of cracks in BWR components.

b) Identify and document reliable means of characterizing and sizing UT indications in pressure vessel seam welds, attachment welds and selected internals.

Goal 5: Reduce the cost of necessary repairs of BWR internals or vessel attachments.

Approach: In collaboration with the service vendors, develop and demonstrate repair techniques for remote or underwater applications.

Table 7 (continued)

Much of the work being done to address the BWR RPV internals is also directly applicable to the vessel. This work is described in the summary table on RPV internals.

KEY REPORTS:

1. *Corrosion–Assisted Cracking of Stainless and Low–alloy Steels in LWR Environments*, EPRI NP–5064M, NP–5064S, February 1987.

2. *Hydrogen Water Chemistry for BWRs: Materials Behavior*, EPRI NP–5080, March 1987.

3. *Hydrogen Water Chemistry to Mitigate Intergranular Stress Corrosion Cracking: In–Reactor Tests*, EPRI NP–5800M, NP–5800–SP, May 1988.

4. *Stress Corrosion Monitoring and Component Life Prediction*, Volumes 1 and 2, EPRI NP–6028–SP, November 1988.

5. *BWR Normal Water Chemistry Guidelines: 1986 Revision*, EPRI NP–4946SR, September 1988.

6. Status report on BWR SCC susceptibility and inspection priorities for reactor vessel to be published June 1990.

7. Status report on weld repair without PWHT to be published June 1991.

Table 8

TITLE: BWR Reactor Recirculation Piping

SPE: 22 and 23

TIME PERIOD: 1978–1989

GENERAL OBJECTIVE: The objective is to provide applications technology to efficiently conduct complete and partial piping replacement. This includes the implementation of developed IGSCC countermeasures, inspection techniques and materials, testing, where appropriate.

SCOPE: Techniques and specifications were developed that involve: minimizing outage time and worker radiation exposure, assuring quality, meeting code and regulatory requirements, providing practical and proven techniques, and maximizing weld inspectability without compromising effectiveness of the replacement and repair process. The scope of this work also included in the evaluation the IGSCC resistance to weld repairs on large–diameter BWR recirculation piping and the benefits of hydrogen water chemistry.

KEY REPORTS:

1. *Verification of IGSCC Resistance in BWR Large–Diameter Pipe*, EPRI NP–3650–LD, July 1984.

2. *Testing of Flawed Pipe Repairs*, EPRI NP–5237–LD, March 1987.

3. *Assessment of Remedies for Degraded Piping*, EPRI NP–5881–LD, June 1988.

4. *Stress Corrosion Monitoring and Component Life Prediction*, Volumes 1 and 2, EPRI NP–6082–SP, November 1988.

5. *Hydrogen Water Chemistry to Mitigate Intergranular Stress Corrosion Cracking: In–Reactor Tests*, EPRI NP–5800M, NP–5800–SP, May 1988.

Table 9

TITLES: NDE Methods, Adequacy of ASME Code ISI Technology, Current Life Assessment Techniques, and New or Emerging Methods for Inspection and Life Assessment

SPL: 22, 23, 24, 27

TIME PERIOD: 1978–1989

DESCRIPTION: These topics are dealt with separately for individual components. NDE and life assessment techniques for all the major components are a significant portion of the work being done at EPRI and are considered an on–going process. A list of selected reports addressing these subjects, some of which are repeated elsewhere, follows.

KEY REPORTS:

NDE Methods

1. *Nondestructive Evaluation Program: Progress in 1987*, EPRI NP–5490–SR, and *Nondestructive Evaluation Program: Progress in 1988*, EPRI NP–6075–SR, in publication.

2. *Feasibility of Using Electromagnetic Acoustic Transducers to Detect Corrosion in Mark I Containment Vessels*, EPRI NP–6090, November 1988.

3. *Nondestructive Evaluation T[illegible]ues for Bolting in Nuclear Power Plants*, EPRI NP–4090, July 1985.

4. *Lamb Wave Inspection fo[illegible]racks in Centrifugally Cast Stainless Steel*, EPRI NP–5963, August 1988.

5. *Inspection of Centrifuga[illegible] Stainless Steel Components in PWRs*, EPRI NP–5131, June 1987.

Adequacy of ASME C[illegible]chnology

1. *Long–Term Inspection Requirements for PWR Pump Casings*, EPRI NP–3491, May 1984.

2. *Nondestructive Examination Acceptance Standards*, EPRI NP–1406–SR, May 1980.

3. *Flaw Evaluation Procedures*, EPRI NP–719–SR, August 1978.

4. *Long–Term Inspection Requirements for Nuclear Power Plants*, EPRI NP–4242, March 1986.

5. *ASME Code, Section XI: In–Service Inspection of Nuclear Power Plant Components, 1984–1985 Revisions and Updates*, EPRI NP–4615, June 1986.

6. *ASME Code Section XI: 1985–1987 Revisions and Updates*, EPRI NP–5744, May 1988.

7. *Nuclear Plant In–Service Inspection Requirements and Practices in Different Countries: A Comparative Review*, EPRI NP–5919, July 1988.

Life Assessment

1. *Assessment of Remedies for Degraded Piping*, EPRI NP–5881–LD, June 1988.

2. *Stress Corrosion Monitoring and Component Life Prediction*, EPRI NP–6082–SP, Volumes 1 and 2, November 1988.

Table 9

3. *CHEC: The EPRI Computer Program for Erosion–Corrosion*, User's Manual, NSAC–112L, June 1987 (Available from EPRI–supplement for two–phase flow NSAC–138L in preparation).

4. *Cable Indenter Aging Monitor*, Interim Report, EPRI NP–5920, July 1988.

5. *FATIGUEPRO: On–Line Fatigue Usage Transient Monitoring System*, EPRI NP–5835–SP, May 1988.

6. *Component Life Estimation: LWR Structural Materials Degradation Mechanisms*, EPRI NP–5461, September 1987.

Table 10

TITLE: LWR Reactor Coolant Pump (RCP) Studies

SPE: 22 and 24

TIME PERIOD: 1981–1989

GENERAL OBJECTIVE: The objective of this work has been to understand both observed and potential failure modes and develop technical guidelines that can be used to increase reliability and improve pump performance.

SCOPE: The early work was directed to analyzing available field information on operating pumps to better define failure modes and in determining the most appropriate methods for rotor static and dynamic evaluation. Important aspects of main coolant pump system analysis were defined. Additional studies on pump seal forces, effects of fluid annuli on pump rotor vibration, and seal failures were conducted to increase pump reliability.

A set of technical guidelines that could be used interactively by the utility, NSSS supplier, architect–engineer, and pump manufacturer was developed to increase the seal system and seal auxiliary system reliability while also improving pump performance.

More recent activities have addressed the inspection and aging evaluation of RCP pump bodies and avoidance of shaft failures in long–term service.

KEY REPORTS:

1. *Main Coolant Pump Shaft Seal Guidelines, Volume 1 – Maintenance Manual Guidelines, Volume 2 – Operational Guidelines, Volume 3 – Specification Guidelines*, EPRI NP–2695, March 1983.

2. *Literature Survey, Numerical Examples, and Recommended Design Studies for Main Coolant Pumps*, EPRI NP–2458, June 1982.

3. *Operation and Design Evaluation of Main Coolant Pumps for PWR and BWR Service*, EPRI NP–1194, September 1979.

4. *Long–Term Inspection Requirements for PWR Pump Casings*, EPRI NP–3491, May 1984.

Table 11

TITLE: BWR & PWR Feedwater Piping

SPE: 21, 22 and 24

TIME PERIOD: 1987–1989

GENERAL OBJECTIVE: Provide utilities with the technology to manage single and two phase flow assisted corrosion deterioration effects in the piping systems of LWR units.[a]

SCOPE: The susceptibility to flow–assisted corrosion damage of LWR steam piping is dependent on alloy content and a large number of water process condition variables. A predictive computational method to establish when and where inspections should be scheduled in highly desirable, has been developed, and is being upgraded by feedback from utility users. Process control mitigation methods have been identified and implemented for many PWRs. Deterioration management guidelines have been developed for BWRs where process methods such as pH control by appropriate additives are not directly applicable. Finally, acceptance criteria and inspection guidelines have been provided for LWR piping systems.

KEY REPORTS: The computational program is available or in use by all U.S. utilities. More recent reports are:

1. *CHEC: The EPRI Computer Program for Erosion–Corrosion*, User's Manual, NSAC–112L, June 1987 (available from EPRI–supplement for two–phase flow NSAC–138L in preparation).

2. "Technology Development by U.S. Industry to Resolve Erosion–Corrosion," *IAEA Corrosion Specialists Meeting, Vienna, Austria, September 12–14, 1988.*

a. Fatigue, the other significant piping issue is addressed via project summarized under that title in Table 17.

Table 12

TITLE: BWR and PWR Control Rod Drive Mechanisms (CRD)

SPE: 21 and 24

TIME PERIOD: 1983–1988

GENERAL OBJECTIVE: The objectives of this work are to provide guidelines for remaining life and improved replacement methods for LWR CRDs.

SCOPE: This program provides experimental data and analytical methods that permit establishing more accurate lifetime estimates of CRDs. In addition, improved CRD handling equipment and methods for replacement were developed. Field environment and actuation data have been utilized to identify part and component sensitivity to fatigue, thermal deterioration and corrosion. A guideline for life assessment is being developed from this information.

KEY REPORTS:

1. *Development of Improved BWR Control Rod Replacement Methods*, EPRI NP-3515, May 1984.
2. *Improved Equipment and Procedures for BWR Control Rod Drive Replacement*, EPRI NP-3895, March 1984.
3. *Improved BWR Fuel Support Piece Grapple*, EPRI NP-3874, January 1985.
4. *Utility Guidelines for Reactor Noise Analysis*, EPRI NP-4970, February 1987.

Table 13

TITLE: BWR and PWR Reactor Cabling and Connections

SPE: 27

TIME PERIOD: 1985 – 1991

GENERAL OBJECTIVE: The objective of the program is to insure that aging degradation from heat, radiation and moisture, is sufficiently well understood to permit accurate predictions of the safe, useful life of cables. This includes development of a methodology to assess remaining life based upon nondestructive in-situ examination techniques.

SCOPE: Test specimens placed in nine operating reactors many years ago are providing information on the long-term aging effects of plant environments on cabling and electrical components. Material property data of samples removed periodically are compared with measured degradation in artificially aged specimens and with the current life prediction methods used to validate acceptability.

Devices that can be used to determine remaining life are being developed. The modulus (slope of force–penetration curve) of cable insulation or jacket material increases as the cable becomes less flexible with age. A comparison of measurements on installed cables with measurements on new or artificially aged cables provides a measure of remaining life. Alternate condition monitoring techniques are being identified and applied to several cable types with artificially induced damage, such as pinholes, cracks, and scrapes. LOCA testing will be used to determine which monitoring technique is best able to characterize accident performance and useful life of cable systems.

KEY REPORTS:

1. *Natural vs. Artificial Aging of Nuclear Power Plant Components*, Interim Report, EPRI NP–4997, December 1986.

2. *Cable Indenter Aging Monitor*, Interim Report, EPRI NP–5920, July 1988.

Table 14

TITLE: Pressurized Water Reactor and Boiling Water Reactor Emergency Diesel Generators (EDG)

SPE: 21 and 24

TIME PERIOD: 1983–1989

GENERAL OBJECTIVE: The objective of this program is to determine the measures that operators can take to improve diesel generator reliability and performance.

SCOPE: The project includes investigation of operating experience of diesel generators in order to identify failure modes and evaluation of the best approach for correcting each failure. These included: design changes, changes in operating, maintenance and inspection procedures and the application of on–line monitoring and diagnostics. An in–plant installation served as the basis for a detailed scoping design of a conceptual diagnostic system using hardware from proven monitoring and diagnostic systems. EDG reliability values that accurately indicate the contribution of EDG unreliability to plant risk have been developed.

In support of the industry efforts to address station blackout and EDG reliability issues, reliability program guidelines have been developed. These guidelines recommend specific activities to identify and implement improvements indicated by EDG test results. These guidelines have also been demonstrated to improve EDG reliability.

KEY REPORTS:

1. *The Reliability of Emergency Diesel Generators at U.S. Nuclear Power Plants*, NSAC 108, September 1986.

2. *Failures Related to Surveillance Testing of Standby Equipment, Volume 2: Diesel Generators*, EPRI NP–4264, September 1985.

3. *Surveillance, Monitoring, and Diagnostic Techniques to Improve Diesel Generator Reliability*, EPRI NP–5924, July 1988.

4. *Investigation of an Emergency Diesel Generator Reliability Program*, NP–6193, October 1988.

Table 15

TITLE: BWR Containment

SPE: 21, 24 and 27

TIME PERIOD: 1986–1990

GENERAL OBJECTIVE: The objective of this work is to address those degradation mechanisms that affect free–standing steel containments; primarily corrosion, fatigue, and IGSCC of the stainless steel bellows.

SCOPE: The primary issues being addressed in this work are: 1) drywell shell general corrosion, 2) local corrosion of the drywell shell at the sand bed and basemat seal, 3) wetwell shell and vent system general corrosion, 4) wetwell local corrosion due to coating deterioration or lack of chemistry control, and 5) vent system and penetration bellows fatigue.

Methods for early detection and monitoring for containment component damage are being evaluated. These methods include expanded visual inspections and ultrasonic thickness measurements. Results indicate that significant leaks can be detected before they become a safety concern. Other work has been aimed at determining methods for conducting an integrated leak rate test more quickly and successfully.

KEY REPORTS:

1. *BWR Pilot Plant Life Extension Study at the Monticello Plant: Phase 1*, Appendices L and M, EPRI NP–5181–SP, May 1987.

2. *Feasibility of Using Electromagnetic Acoustic Transducers to Detect Corrosion in Mark I Containment Vessels*, EPRI NP–6090, November 1988.

3. *Boiling Water Reactor Mark I Containment Life Extension Industry Report*, NUMARC/NUPLEX report in preparation to be published 1989.

Table 16

TITLE: BWR Reactor Internals

SPE: 22 and 23

TIME PERIOD: 1984–1993

GENERAL OBJECTIVE: The objective of this work is to develop improved inspection, evaluation and repair techniques, more resistant materials and water chemistry guidelines to prolong the life of reactor internals.

SCOPE: This work addresses the three main classes of components in which corrosion cracking has occurred in BWR reactor internals; low-strength austenitic components, highly irradiated components, and high-strength components. The work initially centered on those plant-specific factors that have been affecting susceptibility to cracking. Once sufficient field observations were made, the scope moved to providing qualified measures to prevent future damage to sound components and preventing additional damage to afflicted components. This work includes a number of in-plant measurements and demonstrations of remedial techniques.

The effects of irradiation on corrosion cracking are also being evaluated. Work at EPRI has included evaluation of top guide integrity, in-core testing of nickel based alloys, evaluation of critical corrosion potential (ECP) for IASCC, and incore materials, monitoring. Mitigation approaches have centered on material composition and water chemistry control. By 1992, a specification for IASCC resistant materials and water chemistry guidelines will be developed.

Additional programs on internals inspection, evaluation and repair are also in progress. This work is aimed at addressing existing components for continued, safe service.

KEY REPORTS:

1. *Corrosion-Assisted Cracking of Stainless and Low-Alloy Steels in LWR Environments*, EPRI NP-5046M, NP-5064S, February 1987.

2. *Hydrogen Water Chemistry for BWRs: Materials Behavior*, EPRI NP-5080, March 1987.

3. *Hydrogen Water Chemistry to Mitigate Intergranular Stress Corrosion Cracking: In-Reactor Tests*, EPRI NP-5800M, NP-5800-SP, May 1988.

4. *Stress Corrosion Monitoring and Component Life Prediction*, Volumes 1 and 2, EPRI NP-6028-SP, November 1988.

5. *BWR Normal Water Chemistry Guidelines: 1986 Revision*, EPRI NP-4946-SR, September 1988.

Table 17

TITLE: FATIGUE

NUREG/CR-4731 identifies a number of specific topics whose major or sole deterioration issue is fatigue. In this context, this summary is responsive to the following topics noted therein:

- PRESSURIZER SURGE & SPRAY LINE NOZZLES
- REACTOR COOLANT SYSTEM CHARGING AND SAFETY INJECTION NOZZLES
- FEEDWATER PIPING AND NOZZLES

These topics address the bulk of those fatigue issues resulting from those thermal transients that were not examined in either design analysis or in start-up vibration testing. Resolution data for these issues is being obtained from plant measurements activities associated with Key Report 1 (above) that were initiated in 1986. Seven LWR units are involved. Alternate references primarily focus on the RPV, one of the few plant elements where precise knowledge of fatigue propagation rates are highly significant to safety.

SPE: 21, 22 27

TIME PERIOD: 1979-1989

GENERAL OBJECTIVE: Provide utilities with the technology and methods to identify and manage fatigue damage accumulation effects resulting from transients in operating service.

SCOPE: Current fatigue evaluation methods can be substantially improved based on operational observations. Improvements are most notably required in the areas of a) replacement of design assumptions on transients with experiential data or equivalent, b) environmental effects on fatigue crack initiation and growth and c) assessment of damage in components not considered in design analysis. A comprehensive program to meet these objectives is in process of completion. Plant measurements and inspection focused by flaw tolerance evaluations are emphasized. Supplementary work on property refinement and on experimental methods of directly measuring usage factor are included.

KEY REPORTS:

1. *FATIGUEPRO: On-Line Fatigue Usage Transient Monitoring System*, EPRI NP-5835-SP, May 1988.
2. *Analysis of Pressure Vessel Steel Fatigue in LWR Environments*, Only topical reports from Research Project RP20006-20 are available at this time. The program reviews all applicable data and is a basis for ASME Section XI revision. Temperature, product form, impurity effects and heat variations are considered.
3. *Corrosion Fatigue Characterization of Reactor Pressure Vessel Steels*, EPRI NP-2775, December 1982.
4. *BWR Environmental Cracking Margins for Carbon Steel Piping*, EPRI NP-2406, May 1982.

Table 18

TITLE: Thermal Embrittlement of Cast Austenitics

NUREG/CR-4731 identifies this issue as a priority issue and/or an area of concern under the following topics:

- REACTOR COOLANT PUMP BODY
- REACTOR COOLANT PIPING AND SAFE ENDS
- CONTROL ROD DRIVE MECHANISMS

Note that cast materials are utilized in only a limited number of PWR control rod housings.

SPE: 22, 27

GENERAL OBJECTIVE: The objective of this work is to develop a methodology for defining and assuring the integrity of cast austenitic stainless steel components utilized in the primary coolant system of LWRs.

TIME PERIOD: 1982–1989

SCOPE: Cast austenitic components, utilized in primary piping and pump and valve bodies, have demonstrated excellent service capability and are generally resistant to corrosion and stress corrosion phenomena. Principal deterioration modes are thermal embrittlement and thermal or mechanical fatigue. A nominal concern is that the castings are not readily inspectable by usual ultrasonic, ISI techniques. This effort includes an evaluation of the kinetics of embrittlement in terms of composition and temperature, the development of ISI methodology, including in situ hardness determinations and cataloging of initial fabrication defects and processes that determine both the initiation and flaw propagation rates associated with fatigue. All of these are combined in flaw tolerance protocols to provide an inspection protocol that insures the safety and physical integrity of these components.

KEY REPORTS:

1. *Long-Term Inspection Requirements for PWR Pump Casings*, EPRI NP-3491, May 1984.
2. *Guideline Background Document #2, Cast Austenitic Stainless Steel Component Life Estimating*, working EPRI document, RP2643-5, October 1987 to be formally published in 1989.
3. *Detection and Characterization of Defects in Centrifugally Cast Stainless Steel*, EPRI NP-5173, April 1987.
4. *Inspection of Centrifugally Cast Stainless Steel Components in PWRs*, EPRI NP-5131, June 1987.
5. *Ultrasonic Characterization of Centrifugally Cast Stainless Steel*, EPRI NP-5246, June 1987.
6. *Evaluation of Flaws in Austenitic Steel Piping*, EPRI NP-4690-SR, July 1986.
7. *Fracture Toughness Characterization of Thermally Embrittled Case Duplex Stainless Steel*, EPRI NP-5439, September 1987.

Table 19

Summary of Key Life Extension Activities at EPRI

SPE: 27

TIME PERIOD: 1979–1993

Introduction

The focal point of residual life assessment and life extension technology at EPRI is performed under Strategic Program Element (SPE) 27; Nuclear Plant Life Extension. Work in this SPE is conducted in coordination with the Department of Energy (DOE), its contractors, and the Nuclear Utilities Management and Resource Council (NUMARC).

This SPE contains the significant economic and technical feasibility studies to develop, preserve and enhance the PLEX option in support of license renewal. This work has included the plant life extension pilot studies, development of economic evaluation and life cycle management tools, component and cable aging studies, industry report development, component life estimating, and the lead plant projects. The products and key background reports of this SPE are for generic interest to RLA, particularly early feasibility studies, background of codes development, and studies on the deterioration modes of metals.

A number of past EPRI reports address the subject of plant life extension or provide a technology base for it. Those of general interest are the early feasibility studies, background of codes development, and studies on the deterioration models of metals. These reports are detailed in the following annotated summaries.

1. *Extended Life Operation of Light Water Reactors: Economic and Technological Review*, EPRI NP-2418, June 1982.

   A generic review was conducted of the economic and technical aspects associated with the operation of nuclear power plants beyond their normal licensed term. The study is an information source book of this concept. The maximum expenditure for refurbishment that would justify additional periods of operations is derived, and the sensitivity of the results to refurbishment downtime and replacement power cost is presented. Also presented are the project scope and cost estimates to replace a reactor pressure vessel. The appendices contain data designed to develop a basic economic model for evaluating the extended life option. Major replacement and refurbishment options of LWRs are also assessed.

2. *BWR Pilot Plant Life Extension Study at the Monticello Plant: Phase 1*, EPRI NP-5181M, May 1987.

   This report summarizes a 2-year preliminary investigation of life extension at an operating BWR and showed that a 70-year service life is both technically and economically achievable. This pilot study produced a methodology for developing a life extension program that utilities can use at other BWRs.

3. *PWR Pilot Plant Life Extension Study at Surry Unit 1: Phase 1*, EPRI NP-5289P, July 1987.

   Technical, economic, and management planning evaluations of life extension prospects at the Virginia Power Surry unit 1 provide information for enhancing plant reliability and assessing long-term energy supply strategies. Life extension appears technically feasible and economically prudent, but additional work is necessary to evaluate specific materials, subcomponents, and plant systems.

4. *Planning Study and Economic Feasibility for Extended Life Operation of Light Water Reactor Plants*, EPRI TPS 78–788, September 1979.

   This report examines the technological and economic feasibility of operating LWR units beyond their nominal 30–40 year service life. The two purposes in performing this study were to explore the economics of extended plant lifetimes, determining the research and development requirements of extended life decisions and to identify any significant design pre–planning which might be required in order to preserve the extended life option.

5. *The Longevity of Nuclear Power Systems*, EPRI NP–4208, August 1985.

   Nuclear power plants should have a useful service life substantially in excess of 40 years. This report identifies actions and recommends research that should enable utilities to derive maximum economic benefit from this longevity potential.

6. *Long Term Integrity of Nuclear Power Plant Components*, EPRI NP–3673–LD, October 1984.

   This report is one in a series of projects designed to investigate and anticipate long–term inspection requirements of nuclear power plant components. The report examines the potential modes of long–term deterioration of the metals utilized in pressure boundary and reactor components, and attempts to define the prospects of integrity–limiting flaw growth occurring during a unit's expected service life. The project also examines the possible effects of long–term deterioration in type–308 stainless steel castings. Neutron irradiation and crevice corrosion in stainless steels, and embrittlement of ferritic steels are also covered.

7. *Nondestructive Examination Acceptance Standards*, EPRI NP–1406–SR, May 1980.

   This report documents the standards for examination evaluation of Article IWA–3000 and the acceptance standards for flaw indication for Article IWB–3000 in the 1977 edition of the ASME Boiler and Pressure Vessel Code, Section XI, Division 1, Rules for In–service Inspection of Nuclear Power Plant Components. It explains the technical basis for these rules, necessary for understanding how or if modification is required for extended service.

8. *Rationale for a Standard on the Requalification of Nuclear Class 1 Pressure Boundary Components*, EPRI NP–1921, October 1981.

   This report provides a rationale for developing a new industry code or standard to cover all foreseeable situations of component requalification–system considerations, components considerations, and specific methods for component evaluation– are detailed. A discussion of existing documentation that may be useful in requalification and specific proposals for a standard are presented. Although this work was initiated to address requalification as the result of an abnormal operating event, it also provides an excellent basis for life extension analysis.

9. *Flaw Evaluation Procedures*, EPRI NP–719–SR, August 1978.

   This report contains procedures acceptable to the Boiler and Pressure Vessel Code Committee for establishing the acceptability of flaw indications found in nuclear pressure boundary components. A series of example problems that illustrate the evaluation procedures contained in Appendix A are provided. They consider such factors as flaw location, size, and growth due to normal and abnormal loads, degradation of properties due to neutron fluence, and the application of linear elastic fracture mechanics. The technical basis for the fracture analysis methods of Appendix A is provided. This document illustrates a specific approach to formal life estimating. Application to life extension will require consideration of deteriorations other than flaws as well as updating of the methods and data incorporated.

10. *Long-Term Inspection Requirements for Nuclear Power Plants*, EPRI NP-4242, March 1986.

    A fundamental requirement of in-service inspection programs is to detect the initiation and growth of crack-like flaws. This report provides a guide to current inspection planning for cast austenitic PWR components. Consistent plant-to-plant ISI programs are expected to yield valuable information on the service condition of plant components and materials. This report will assist utility personnel establish a definable ISI plan for cast austenitic PWR components.

11. *Review of Records Requirements Related to LWR Life Extension*, EPRI NP-4926, November 1986.

    This report summarizes the current requirements for ISI and for records of inspection and operating performance data relevant to plant life extension. It concludes that much of the existing test and inspection data is of potential benefit to life extension evaluations, particularly in establishing baselines.

12. *Generic Guidelines for the Life Extension of Fossil Fuel Power Plants*, EPRI CS-4778, November 1986.

    This report provides a comprehensive set of guidelines on extending fossil plant life and is designed to provide information that will help utilities establish and implement their own program. The guidelines recommended for fossil plant life extension provide some insight into the nuclear plant life extension program, most notably for balance-of-plant components operating at similar conditions.

13. *LWR Plant Life Extension*, Interim Report EPRI NP-5002, January 1987.

    This is an interim report presenting the results of pilot plant life extension studies conducted by Virginia Power and Northern States Power to assess NUPLEX feasibility. It presents the results of the first detailed U.S. utility study on plant life extension. It concludes that NUPLEX is technically feasible and is an economical means of providing electricity through the next century.

14. *Characterization of the Performance of Major LWR Components*, EPRI NP-5001, January 1987.

    This report presents a summary of the performance history of major LWR components, including pertinent failure and repair information, for use in assessing nuclear plant life extension options. The history of the in-service performance of major LWR components will help utility engineers project the performance issues and refurbishment requirements likely to arise in extending the service life of nuclear power plants.

15. *EPRI Operations and Maintenance Source Book*, EPRI NP-49B6 SR, February 1987.

    This report provides a single reference to more than 200 reports and products generated since 1973 that support nuclear power plant operations and maintenance. It provides utility personnel with background and supporting data on past EPRI research that may support NUPLEX activities.

16. *BWR Pilot Plant Life Extension Study at the Monticello Plant: Interim Phase 2*, EPRI NP-5836M, October 1988.

    This report is a continuation of the work reported in NP-5181M. Tests and evaluations at Northern States Power Company's Monticello BWR continue to confirm the savings estimate and demonstrate important preventive maintenance techniques offering immediate benefits.

Table 19 (continued)

17. *NUPLEX Project Briefs*, EPRI NP-5388-SP, Revision 1, October 1988.

This revision to the 1987 "NUPLEX Project Briefs" provides an overview of major life extension issues. The report assembles technical information on PLEX for utility use. It includes information on new research and field information, and serves as a reference on nuclear plant life extension.

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11. ABSTRACT (200 words or less)

This report presents an assessment of the aging (time-dependent degradation) of selected major light water reactor components and structures. The stressors, possible degradation sites and mechanisms, potential failure modes, and current inservice inspection requirements are discussed for eleven major light water reactor components: reactor coolant pumps, pressurized water reactor (PWR) pressurizers, PWR pressurizer surge and spray lines, PWR reactor coolant system charging and safety injection nozzles, PWR feedwater lines, PWR control rod drive mechanisms and reactor internals, boiling water reactor (BWR) containments, BWR feedwater and main steam lines, BWR control rod drive mechanisms and reactor internals, electrical cables and connections, and emergency diesel generators. Unresolved technical issues related to understanding and managing the aging of these major components are identified.

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Aging, Degradation Sites and Mechanisms, Stressors, Residual Life, License Renewal, PWR and BWR Primary Pressure Boundary Components, Feedwater Lines, Containments, Cables and Connections, Emergency Diesel Generators, Inservice Inspections, Monitoring Methods

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