PNL-10717
Part 2 of 2

A Review of Information for Managing Aging in Nuclear Power Plants

Compiled by

J. V. Livingston
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September 1995

Prepared for
Division of Engineering Technology
Office of Nuclear Regulatory Research
U.S. Nuclear Regulatory Commission
under a Related Services Agreement with the
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Richland, Washington 99352

Preface

This report collects, critically reviews, summarizes, and integrates publicly available information pertaining to understanding and managing age-related degradation of systems, structures, and components (SSCs) in nuclear power plants. The two parts contain pertinent information useful for understanding aging mechanisms and identifying degradation sites in these systems, structures, and components and managing degradation through effective monitoring and maintenance programs or by modifications to operating conditions. Because of its summary nature, the information contained in this report is not intended to be sufficiently detailed to satisfy all applications. Extensive references have been provided to guide the reader to more comprehensive sources when needed.

Part 1 of this report reviews information on understanding and managing aging of long-lived, passive, nonredundant systems and components. Other SSCs that have been subjects to NPAR investigations are summarized in Part 2. The SSCs covered in Part 2 are active systems used to maintain the desired operational safety margins in nuclear power plants.

This review should not be considered complete because of the rapidly changing stateof-theart of aging technology and the difficulty of identifying, obtaining, and correctly interpreting all existing sources of information. Assessments of aging and its mitigation is a complex process subject to differences in interpretation. Perspectives cited in this report should be considered preliminary because of the uncertainties generated by the foregoing qualifications. These perspectives do not reflect regulatory positions or requirements.

Abstract

Aging degradation in safety and support systems of nuclear power plants should be managed to prevent safety margins from eroding below the acceptable limits provided in plant design bases. The Nuclear Plant Aging Research (NPAR) Program, conducted under the auspices of the U.S. Nuclear Regulatory Commission (NRC), Office of Nuclear Regulatory Research, and other related aging management programs are developing technical information on managing aging. The aging management process central to these efforts consists of three key elements: 1) selecting structures, systems, and components (SSCs) in which aging should be controlled, 2) understanding the mechanisms and rates of degradation in these SSCs, and 3) managing degradation through effective inspection, surveillance, condition monitoring, trending, record keeping, maintenance, refurbishment, replacement, and adjustments in the operating environment and service conditions. This document concisely reviews and integrates information developed under NPAR and other aging management studies and other available information related to understanding and managing age-related degradation and provides specific references to more comprehensive information on the same subjects.

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Abbreviations/Acronyms

AFWS	auxiliary feedwater system
ALARA	as low as reasonably achievable
AMG	aging management guidelines
ASME	American Society of Mechanical Engineers
ATWS	anticipated transient without scram
B&W	Babcock and Wilcox
BOCRDS	balance of the CRDS
BVs	block valves
BWR	boiling-water reactor
BWST	borated water storage tank
CBs	circuit breakers
CCWS	component cooling water systems
CE	Combustion Engineering
CRA	control rod assembly
CRDS	control rod drive system
CRDM	control rod drive mechanism
CVCS	chemical and volume control system
CVs	check valves
CY	calendar year
DHR	decay heat removal
DOP	dioctylphthalate
EAS	essential auxiliary supporting (system)
ECAD	electronic characterization and diagnostics (system)
ECCS	emergency core cooling system
EDG	emergency diesel generator
EPDM	ethylene propylene diene monomer
EPRI	Electric Power Research Institute
ESF	engineered safety feature
ESFAS	engineered safety features actuation system
FSARs	Final Safety Analysis Reports
HCU	hydraulic control unit
HEPA	high-efficiency particulate air (filters)
HFIR	High Flux Isotope Reactor
HPCI	high pressure coolant injection (system)
HPCS	high pressure core spray (system)
HPI	high-pressure injection
HPIS	high pressure injection system
HVAC	heating, ventilating, and air-conditioning
HX	heat exchangers
I&C	instrumentation and control

IAS	instrument air system
ICS	isolation condenser system
IEEE	Institute of Electrical and Electronics Engineers. Inc.
IGSCC	intergranular stress corrosion cracking
ISM	inspection, surveillance, and monitoring
ISMM	inspection, surveillance, and monitoring methods
IST	inservice testing
LCSR	loop current step response (tests)
LOCA	loss-of-coolant accident
LOP	loss of offsite power
LPIS	low pressure injection system
MCCs	motor control centers
MDPs	motordriven pumps
MOVs	motor-operated valves
NASA	National Aeronautics and Space Administration
NDE	nondestructive evaluation
NDT	nondestructive testing
NPAR	Nuclear Plant Aging Research Program
NPPs	nuclear power plants
NPRDS	nuclear plant reliability data system
NRC	U.S. Nuclear Regulatory Commission
NST	neutron shield tank
ORNL	Oak Ridge National Laboratory
PI	power interrupt (test)
PNL	Pacific Northwest Laboratory
PO	piston-over
PORVs	power-operated relief valves
PRA	probabilistic risk assessment
PU	piston-under
PWR	pressurized-water reactor
RCIC	reactor core isolation cooling
RCS	reactor coolant system
RES	Office of Regulatory Research
RHR	residual heat removal
RPS	reactor protection system
RPV	reactor pressure vessel
RTDs	resistance temperature detectors
RTS	reactor trip system
SAS	service air system
SCC	stress corrosion cracking
SCR	silicon controlled rectifier
SGs	steam generators
SI	safety injection
SLC	standby liquid control (system)
SOVs	solenoid-operated valves
SSCs	systems, structures, and components
SSE	safe shutdown earthquake
SWS	service water system

TDPs	turbine-driven pumps
TGSCC	transgranular stress corrosion cracking
UHS	ultimate heat sink

1 Introduction

For several years the Nuclear Plant Aging Research (NPAR) Program[1] has been developing technical understanding of the processes that, through timedependent age-related degradation of systems, structures, and components (SSCs), could reduce operational safety margins in operating nuclear power plants (NPPs) below acceptable limits. Complementary aging management programs are conducted by the Materials Engineering Branch and the Structural and Seismic Engineering Branch of the U.S. Nuclear Regulatory Commission (NRC), Office of Regulatory Research (RES), Division of Engineering; these programs focus on the development of improved nondestructive examination techniques and on understanding and managing age-related degradation of NPP pressure vessels, piping steam generators, and civil structures. Parallel programs, focused on developing the understanding needed to improve the reliability and prolong the useful life of NPP SSCs, have been instituted under the guidance of the Electric Power Research Institute (EPRI). Similar programs are being conducted in other countries, and complementary programs are being conducted to improve aging management practices in other industries, such as United States commercial and Air Force aviation programs, the U.S. Navy Extended Operating Cycle Program for nuclear submarines, and the National Aeronautics and Space Administration (NASA) programs to develop improved nondestructive examination techniques.

Pacific Northwest Laboratory (PNL)[2] conducted this review to consolidate the information being developed by these programs in a form that is "user friendly" for both the NRC staff and NPP licensees. Because of its summary nature, the information contained in this report is not intended to be sufficiently detailed to satisfy all applications. Extensive references have been provided to guide the reader to more comprehensive sources.

1.1 Organization

Part 1 of this report reviews information on understanding and managing aging of long-lived, passive, nonredundant systems and components. Other SSCs that have been subjects to NPAR investigations are summarized in Part 2. The SSCs covered in Part 2 are active systems used to maintain the desired operational safety margins in NPPs. Degradation of these systems may or may not directly affect the operability of the plant, but can impact the overall plant safety. The systems are presented in no specific order and not intended to imply any ranking or importance.

Each section of the report addresses a particular SSC and describes the aging concerns and mechanisms as well as approaches to managing the degradation. Further subdivisions are made where significant differences exist between boiling water reactors (BWRs) and pressurized-water reactors (PWRs) SSC aging issues. References are provided at the end of each section.

1.2 Terminology

Terminology used in this report follows consensus definitions developed by a technical committee composed of members from the utility industry and regulatory research (Grant and Miller 1992).

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[1]Conducted under the auspices of the Division of Engineering, Office of Regulatory Research (RES), U.S. Nuclear Regulatory Commission (NRC).
[2]PNL is operated by Battelle Memorial Institute for the U.S. Department of Energy.

1.3 Aging and Research Programs

The status and accomplishments (through calendar year [CY] 1990) of the NPAR Program are reviewed by Vora (1991); Bosnak (1992) gives an updated overview of the program.

Reports generated in the NPAR Program (through September 1993) are summarized and indexed by Vora (1993); this report has been updated annually for 4 years.

Scott et al. (1992) summarize pertinent insights regarding aging management practices of the United States commercial airline industry, the U.S. Air Force B-52 bomber program, the U.S. Navy ballistic submarine fleet, and the Japanese nuclear power industry.

1.4 General Guidance

Christensen (1992), Dukelow (1992), and Vora and Bums (1989) are good sources for general information regarding the need for, and the processes necessary to establish, effective aging management programs.

Blahnik et al. (1992), Fresco et al. (1993), Gunther and Taylor (1990) and Shah and MacDonald (1993) are good sources for summary reviews of insights gained from specific NPAR activities.

1.5 References

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Vora, J.P. and J.J. Bums. 1989. "Understanding and Managing Aging and Maintenance." In *Proceedings of the International Nuclear Power Plan Aging Symposium.* ed. F.A. Beranck, NUREG/CP-01000, pp. 28-38, U.S. Nuclear Regulatory Commission, Washington. D.C.

2 Control Rod Drive Systems

Reactivity control is achieved in power reactors during startup, shutdown, flux shaping at power, and emergency shutdown (scram) by the use of a control rod drive mechanism (CRDM) to position each neutron-absorbing control rod assembly (CRA) within the reactor core.

2.1 PWR Control Rod Drive Mechanism

Pressurized-water reactor (PWR) CRDMs are flange mounted on top of the reactor pressure vessel (RPV) head. A roller nut/leadscrew design is used for positioning in Babcock and Wilcox (B&W) plants (Figure 2.1), while a magnetic jack design is utilized in Westinghouse and most Combustion Engineering (CE) plants (Figures 2.2 and 2.3). (A rack and pinion mechanism is used in two CE plants instead of the magnetic jack type (Figure 2.4).) Externally mounted stator coils are used in most models to provide the magnetic field which activates the roller nuts or magnetic latches resulting in control rod movement (Grove and Gunther 1993). Loss of AC power results in a rapid gravitydriven insertion of the control rods.

2.1.1 Aging Concerns and Mechanisms

A wide range of stresses act upon the CRDM and contribute to aging phenomena. These stresses are of diverse nature, including mechanical (wear, fatigue, vibration), chemical (corrosion), electrical (arcing, power surges, electrical noise, drift), environmental (temperature, radiation, humidity), and miscellaneous (abnormal operating conditions, improper or excessive maintenance, testing, and human error) (Grove et al. 1992).

Table 2.1 summarizes the aging mechanisms that result from these stresses and degrade CRDM components given adequate time and proper conditions. Stress corrosion cracking is an aging mechanism that can occur with susceptible materials under stress, tensile or compressive, in a corrosive medium. Primary water SCC attacks Alloy 600 components subjected to high residual tensile stresses, while transgranular SCC (TGSCC) produces leaks in welds which have been exposed to stagnant concentrations of chlorides and sulfates. Leakage of the primary coolant can cause aging without any stress because of boric acid corrosion. Thermal stresses can degrade CRDM components, especially stainless steel castings, by thermal embrittlement or low-cycle fatigue. Mechanical wear, in the form of spalling or erosion, deteriorates all mating sub-components. Insulation breakdown in the stator or lift coils leads to electrical malfunctions. such as inadvertent rod insertion.

Failures from 1980 to 1990 were most frequently encountered in the power and logic systems, followed by the CRDM, rod position indicator, cables and connectors, and finally in miscellaneous components such as control rods and guide tubes. Approximately 40% of these failures were directly attributable to time-dependent aging. Another 30% to 50% may have been caused by aging (Grove et al. 1992).

2.1.2 Managing Aging Degradation

Table 2.2 summarizes management options for dealing with aging degradation. Performance tests, first among these options, are needed to detect aging by trending component degradation. Although common in the nuclear industry, failure/no failure tests, such as the meggering of cables, should be replaced by more descriptive inspection techniques.

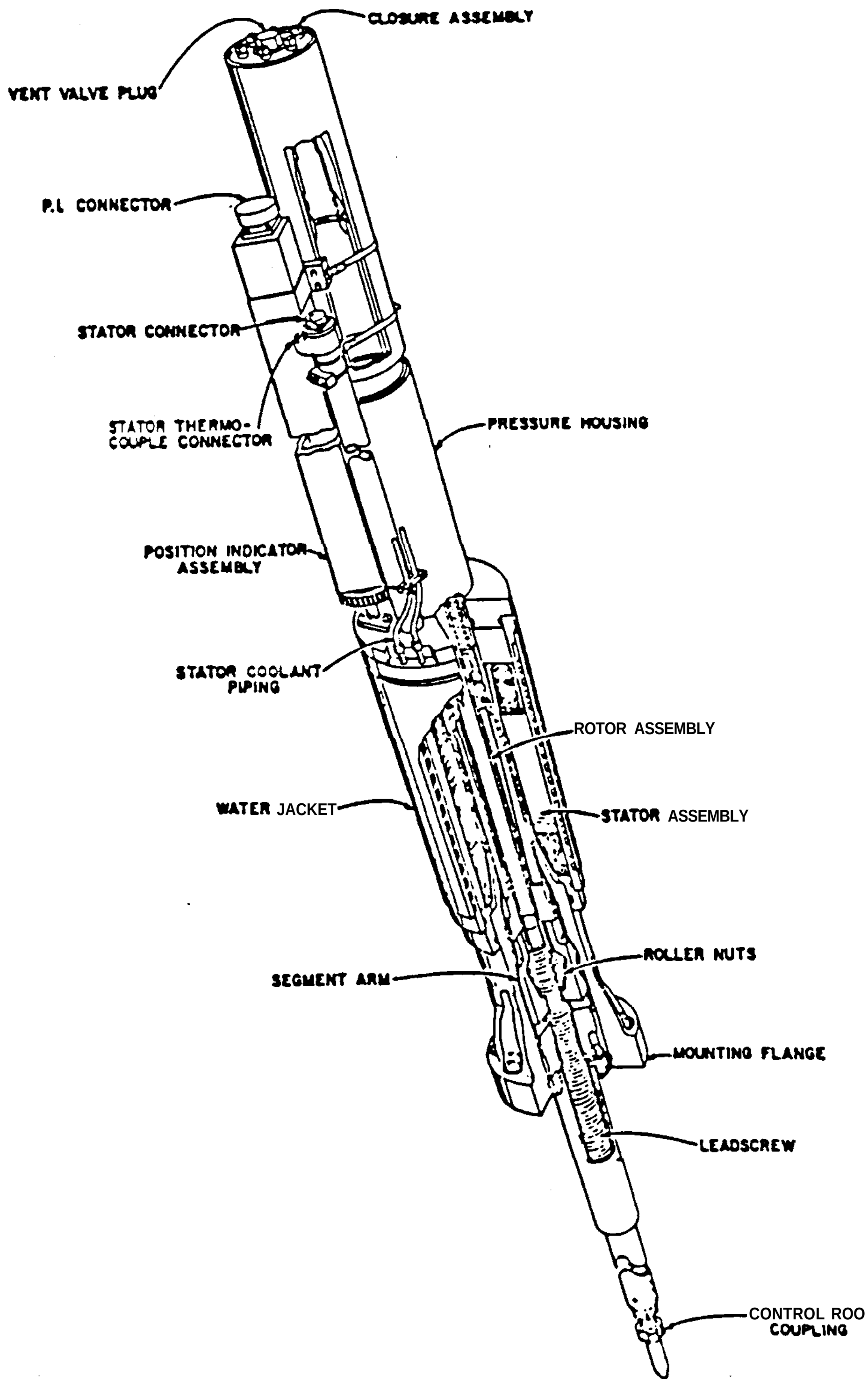

Figure 2.1 Roller nut CRDM

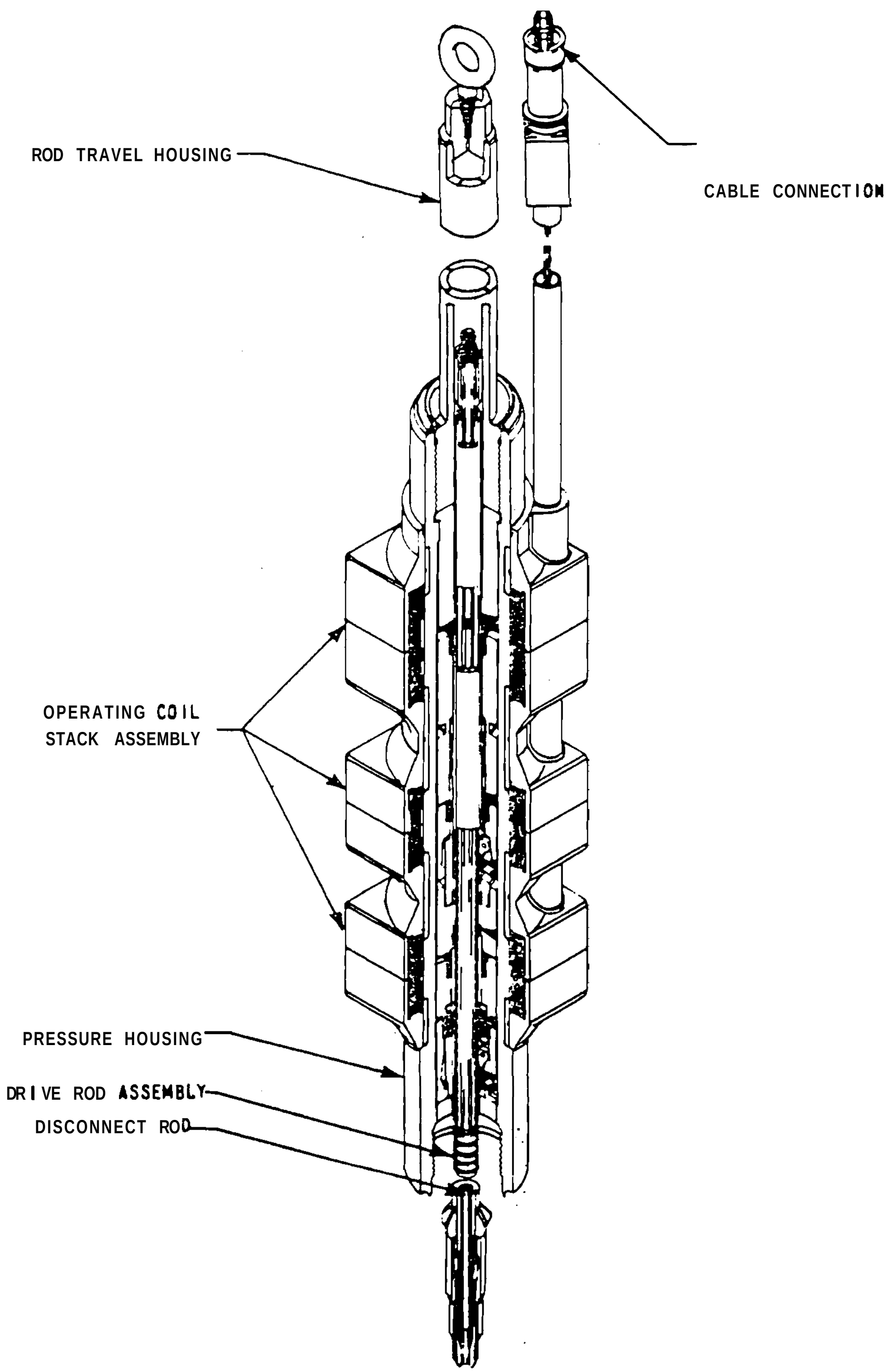

Figure 2.2 Westinghouse magnetic jack CRDM

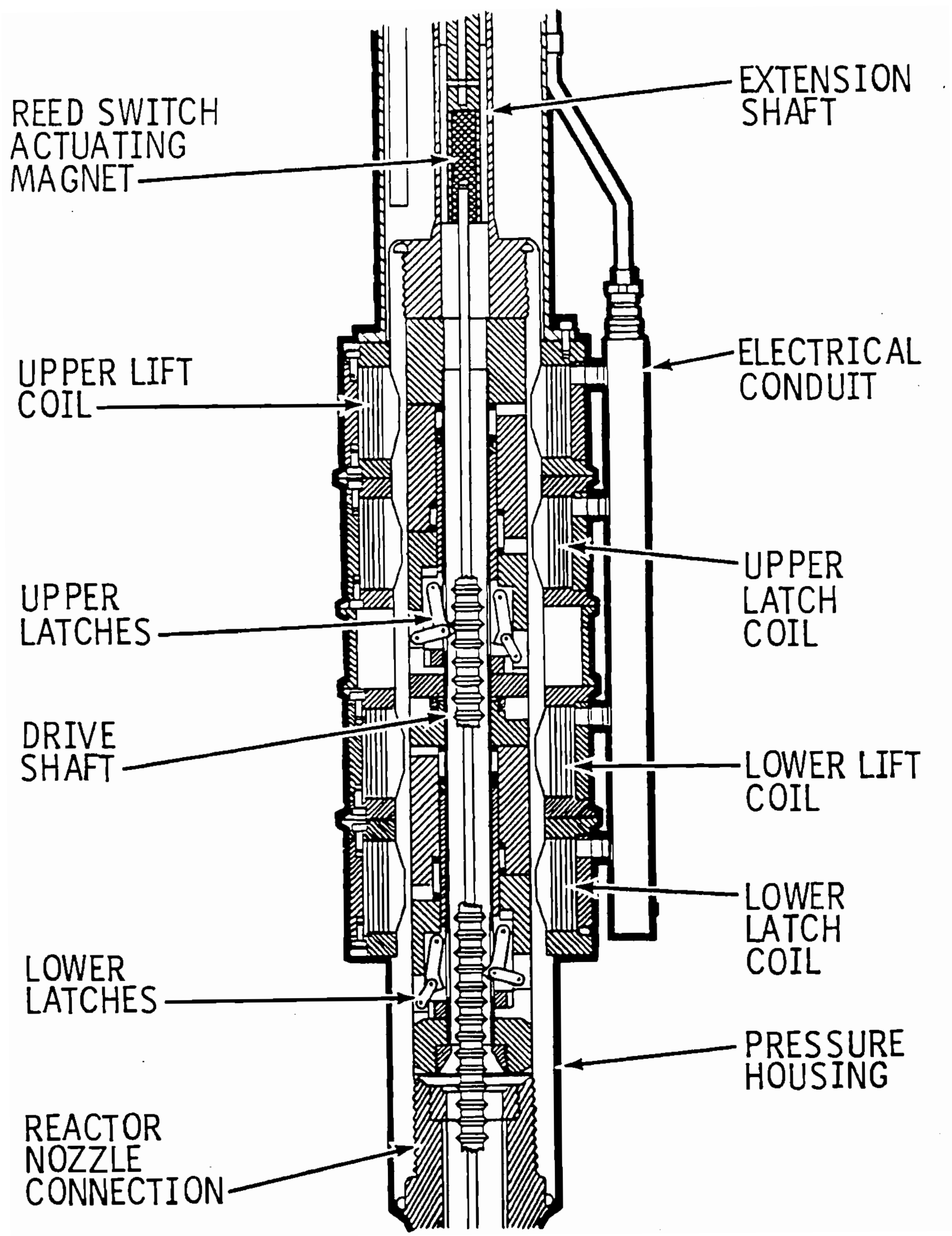

Figure 2.3 Combustion engineering magnetic jack CRDM (CESSAR 1985)

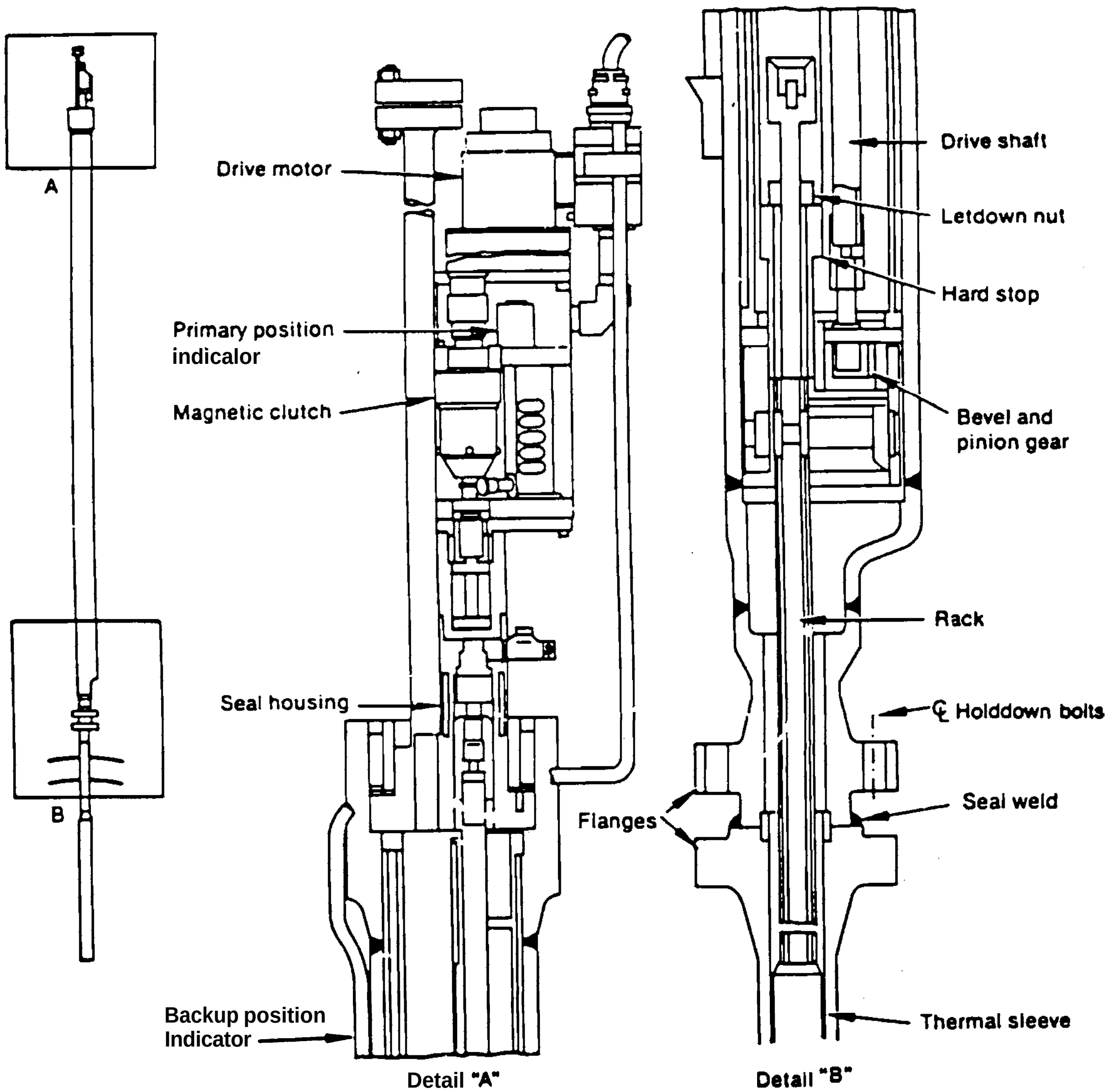

Figure 2.4 Combustion egineering rack and pinion CRDM (Grove and Gunther 1993)

Electrical components can be analyzed more precisely by an Electronic Characterization and Diagnostics (ECAD) System. This system can assess the integrity and operability of various electrical circuits by measuring standard electrical characteristics. These data can then be compared against established reference baselines in order to estimate component degradation, allowing time for corrective maintenance if necessary (Pentecost et al. 1990).

Visual inspections help to detect leaks and determine the mechanical condition of the drive shaft, guide tubes, and control rods. During refueling operations, the drive rod, seals, welds, and vent valve can be inspected for physical aging and primary coolant leakage. The American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code requires that at least 10% of the welds on periphery housings be examined every 10 years (ASME 1992). Some B&W plants have started a gasket inspection program to examine the interior housings as well (Grove and Gunther 1993).

Table 2.1 Aging concerns and mechanisms in PWR CRDM systems

Component	Materials	Aging Concerns	Aging Mechanisms	Reference
Spider	Stainless Steel	Surface Cracks, Dropped Rod, Stuck Rod	Stress Corrosion Cracking, Wear, Fatigue, Radiation Embrittlement	Grove, Gunther, and Sullivan 1992, Table 1
Fuel Assembly Guide Tube	Zircaloy-4	Cracking Wear, Stuck Rod	Wear	
Control Rods	Type 304 Stainless Steel Cladding. Inconel, Ag-In-Cd, B_4C Poison	Clad Cracking, Poison Wash Out	Stress Corrosion Cracking, Wear	
Split Pin	Inconel	Stuck Rod, Loose Parts	Stress Corrosion Cracking	
Rotor Assembly, Latch Assembly	Stellite, Stainless Steel	Dropped CRA, Immovable CRA	Wear, Fatigue, Debris Buildup	
Leadscrew Drive Rod	Stainless Steel	Dropped Rod, Immovable CRA, Inoperable Locking Mechanism	Wear, Fatigue, Stress Corrosion Cracking	
Coil Stack	Copper Wire, Epoxy, Kapton	Dropped Rod, Electrical Short, Voltage Variation, Spurious Rod, Control Alarms, Incorrect Rod Position	Corrosion, Wear, Insulation Breakdown, Fatigue, Thermal Embrittlement	
Vent Valve	Stainless Steel, O-rings	Inoperable Valve, Primary Coolant Leak	Corrosion Buildup, Wear, Fatigue, Thermal Embrittlement	
Power and Control System	Semi-conductors, Cables, Connectors, SCRs	Dropped CRA, Spurious CRA Movement, Inoperable Rods, Electrical Signal Drift	Corrosion Fatigue, Wear, Thermal Degradation, Output Draft, Power Surge	
Rod Position Indication Systems	Reed Switches, Stepping Motor, Wiring, Cables, Connectors, Imear Transformer Detector	Loss of Position Indication, Spurious Position Indication	Corrosion, Fatigue, Wear, Thermal Degradation, Vibration, Electrical Draft, Insulation Breakdown	

Degradation trending is provided by non-invasive, commercially-available advanced monitoring techniques. Motor current signature analysis verifies proper CRDM operation by checking for wear, bearing, and seal failures. Infra-red thermography inspects electronic components for over-heating. Other advanced monitoring techniques, such as eddy current, ultrasonic, and profilometry inspection, help reveal thinning from wear and corrosion. Eddy current monitoring, for example, uses coil probes to find defect locations and estimate penetration depth, axial length, circumferential length, and remaining local wall thickness (Dobbeni 1990).

All CRDM components deemed close to failure by the various inspection techniques should be repaired or replaced, depending on the component, aging mechanism, and degree of degradation. Corrective maintenance may be facilitated by an operating database capable of alerting utility personnel of component failures at other plants (Grove et al. 1992).

If aging degradation is not discovered by inspection techniques, aging-related problems may appear during routine reactor operation, with the possibility of shutdown. At the Unit 1 Plant on Three Mile Island, an operator noticed an overlap in the average positions of two control rod groups. After review, the irregularity was traced to a faulty programmer motor (Licensed Event Report 1994). The Palisades Plant was brought from full power to shutdown mode when an abnormal decreasing trend was observed in the level of the volume control tank. Faulty mechanical seals were found to be responsible for this event by their leakage of primary coolant (Licensed Event Report 1993). The first incident was handled by the replacement of an entire programmer assembly, while the second was corrected by repair of the mechanical seal packages.

Table 2.2 Managing aging in PWR CRDM systems

Component	Materials	Aging Mechanisms	Management Options	Reference
Spider	Stainless Steel	Stress Corrosion Cracking, Wear, Fatigue, Radiation Embrittlement	Conduct NDE performance testing and evaluate trends; rebuild components that approach degradation limits of operation; routinely rebuild or replace components on a 10 year frequency; and use optimum developed innovative tools, equipment, and procedures.	Grove, Gunther, and Sullivan 1992, Table 1
Fuel Assembly Guide Tube	Zircaloy-4	Wear		
Control Rods	Type 304 Stainless Steel Cladding, Inconel, Ag-In-Cd, B_4C Poison	Stress Corrosion Cracking, Wear		
Split Pin	Inconel	Stress Corrosion Cracking		
Rotor Assembly, Latch Assembly	Stellite, Stainless Steel	Wear, Fatigue, Debris Buildup		
Lead Screw Drive Rod	Stainless Steel	Wear, Fatigue, Stress Corrosion Cracking		
Coil Stack	Copper Wire, Epoxy, Kapton	Corrosion, Wear, Insulation Breakdown, Fatigue, Thermal Embrittlement		
Vent Valve	Stainless Steel, O-rings	Corrosion Buildup, Wear, Fatigue, Thermal Embrittlement		
Power and Control System	Semi-conductors, Cables. Connectors, SCRs	Corrosion Fatigue, Wear, Thermal Degradation, Output Draft, Power Surge		
Rod Position Indication Systems	Reed Switches, Stepping Motor, Wiring, Cables, Connectors, lmear Transformer Detector	Corrosion, Fatigue, Wear, Thermal Degradation, Vibration, Electrical Draft, Insulation Breakdown		

2.2 BWR Control Rod Drive Mechanism

Boiling-water reactor (BWR) CRDMs differ from their PWR counterparts in that they are mechanical-hydraulic devices, rather than electrical-mechanical, and that they are mounted on the bottom of the RPV, instead of the top. The bottom mounting connects to a flange on the CRDM housing by bolting, while the upper portion joins to the CRA through a coupling assembly. A schematic of a BWR control rod drive is provided in Figure 2.5.

Demineralized water serves as the control rod drive (CRD) system operating fluid and through its movement the control rod is positioned. Each CRDM requires a hydraulic control unit (HCU) to supply this hydraulic fluid and to regulate its pressure and operating flow. An array of valves, pumps, and headers outside of the HCU, commonly referred to as the balance of the CRD system (BOCRDS), provides additional regulation of the operating fluid.

2.2.1 Aging Concerns and Mechanisms

Boiling-water reactor stresses are generally the same as those acting upon PWRs (i.e., mechanical, chemical, electrical, and environmental). However, these stresses create a unique set of aging concerns because of the different reactor operating conditions and design.

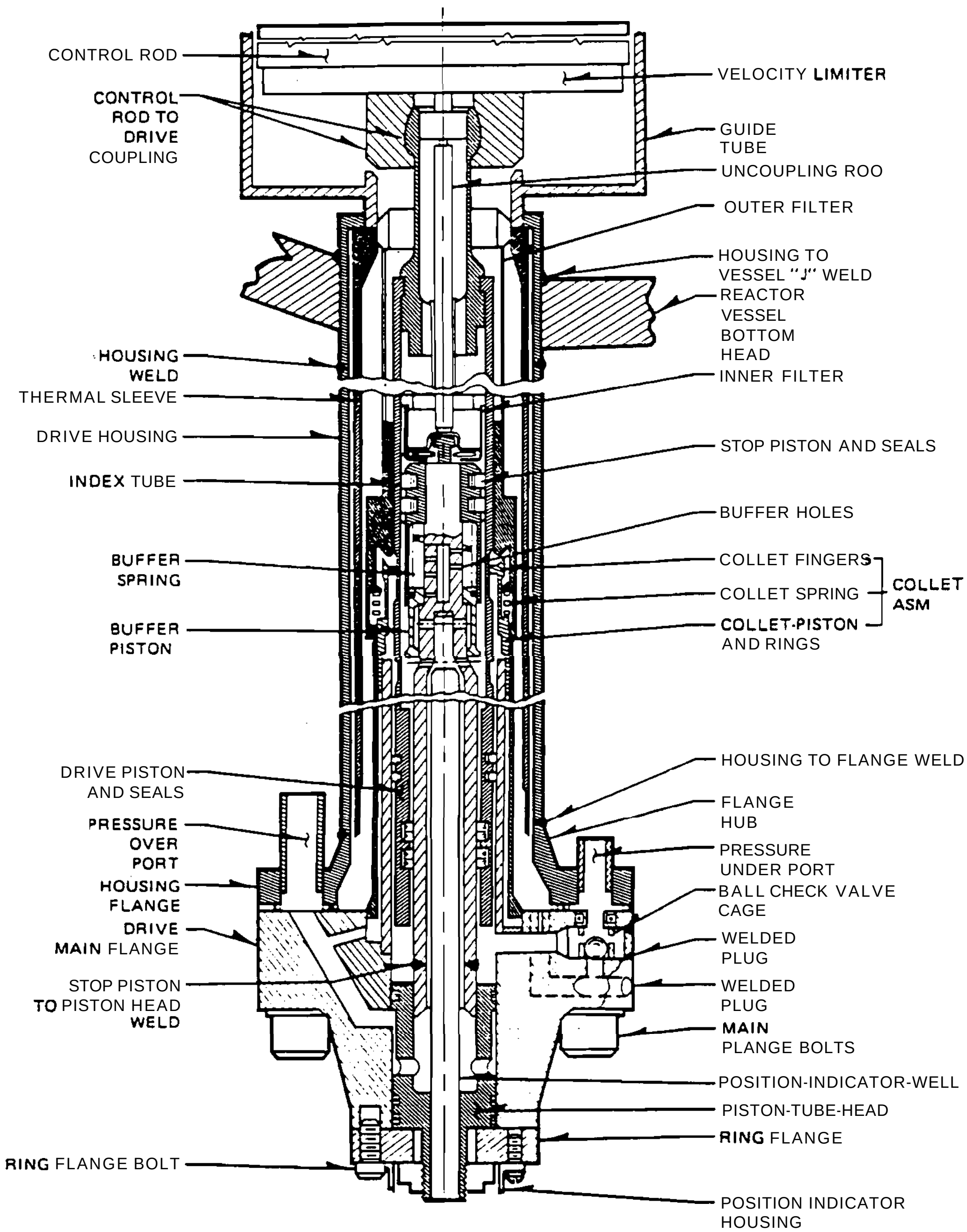

Figure 2.5 BWR control rod drive schematic (River Bend Station FSAR)

Table 2.3 lists the predominant aging concerns along with the responsible mechanisms and affected components. Intergranular stress corrosion cracking (IGSCC), most troublesome of the aging mechanisms, attacks metals which have been made susceptible during manufacturing by certain heat treatments and welding For instance, the nitriding process weakens the stainless steel collet housing by a heat treatment which depletes chromium at the grain boundaries. Transgranular stress corrosion cracking requires a high chloride concentration and threshold temperature. Thermal fatigue results from control rod motion, specifically scram and rod insertions which produce severe temperature changes in short time periods and thermal gradients across tube walls. Corrosion is dangerous not only because of component erosion itself, but also the damage caused by corrosion products. Debris can plug areas, like the cooling-water orifice. or become entrapped in filters and under seals. Other aging mechanisms include thermal embrittlement. mechanical wear, rubber degradation. and radiation damage.

According to a recent NPAR study, over 59% of system component failures take place in the HCU (valve seals, discs, seats, stems, packing, and diaphragms). Control rod drive mechanism component failures account for about **23%** of these failures, usually due to wear and aging of the Ciraphitar seals, with the remaining failures in the BOCRDS (Greene 1992).

Table 2.3 Aging concerns and mechanisms in BWR CRDM systems

Component	Materials	Aging Concerns	Aging Mechanisms	Reference
Index Ttube, Ppiston Ttube, Gguide Ccap, Ccollet Aassembly	Type 304L, Stainless Steel	Leaks, Failure to Operate, Cracks	Corrosion, Intergranular Stress Corrosion Cracking Degraded Nitride Surfaces	Greene 1992 p. 27-32
Graphite Seals	Graphite	Leaks	Scarred Surface from Loose Crud, Thermal Degradation	
Inner Filter	(not provided)	CRDM Uncoupling	Reassembly Error	
Cooling Water Orifice	(not provided)	Restricted Flow	Loose Crude Plugs Orifice	
Inconel X-750 spud	Inconel X-750	Uncoupling	Deformation	
CRDM	Type 304L Stainless Steel	Failure to Operate	Deformation and Corrosion During Storage	
Scram Water Accumulator	Cr Plated Type 304L Stainless Steel	Plugged Orifices	Separation of Cr Plating	
Scam Valves and Solenoids	(not provided)	Failure to Operate	Wear, Intergranular Stress Corrosion Cracking	
BOCRDS Valves, Actuator, Pumps, Bearings, and Seals	(not provided)	Leaks, Failure to Operate	Wear, Adjustment Drift, Erosion	
Maintenance and Replacement Activities	(not applicable)	Reliability	Operator Error, Incorrect Replacement Materials	

2.2.2 Managing Aging Degradation

Control rod drive system failures are detected primarily by scheduled testing and routine observation **(72%),** occasionally by control room observations (24%), and rarely because of a failed service demand (2%) (Greene 1992). Table 2.4 lists several testing techniques recommended as management options for assessing component degradation.

Once system failures are discovered, component servicing (29%)and component replacement (51%) can restore the CRDM to full operation with total CRDM replacement being seldom necessary (19%). Components that should always be replaced when rebuilding a CRDM include elastomer seals, **Graphitar** seals, all locking bands, all o-rings, the cotter pin, safety wiring, spring washers and various screws. (Other high-wear components that could be considered for mandatory replacement are the inner and outer filters, the check valve ball. strainer, spuds, collet housings, and seal cups **[Greene 1992].)**

Table 2.4 Managing aging in BWR CRDM systems

Component	Materials	Aging Mechanisms	Management Options	Reference
Index Tube, Piston Tube, Guide Cap, Collet Assembly	Type 304L, Stainless Steel	Corrosion, Intergranular Stress Corrosion Cracking, Degraded Nitride Surfaces	Trend degradation with performance testing; Rebuild components showing performance degradation or replace after 10 years service; Replace Type 304 SS Models A, B, and C collet assembly drives with Type 304L SS Models D, E, and F;	Greene 1992 p. 27-32
Graphite Seals	Graphite	Scarred Surface from Loose Crud, Thermal Degradation	Monitor stall flows; Vacuum bottom of reactor vessel around guide tubes; Replace with new improved seal materials	
Inner Filter	(not provided)	Reassembly Error	Test for Proper Installation	
Cooling Water Orifice	(not provided)	Loose Crude Plugs Orifice	Monitor drive temperatures; Retrofit cooling water orifices with upgrade kit	
Inconel X-750 spud	Inconel X-750	Deformation	Test for disengaged CRDM; Replaced damaged spud	
CRDM	Type 304L Stainless Steel	Deformation and Corrosion During Storage	Inspect for corrosion and deformation; Handle and store in approved supports and store in triethanolamine or desiccant	
Scram Water Accumulator	Cr-plated Type 304L Stainless Steel	Deparation of Cr Plating	Test for plugged orifices; Replace with Type 304L liner	
Scam Valves and Solenoids	(not provided)	Wear, Anter Dranular Etress corrosion cracking	Inspect for wear and corrosion; Rebuild degraded components	
BOCRDS Valves, Actuator, Pumps, Bearings, and Seals	(not provided)	Wear, Adjustment Drift, Erosion	Conduct periodic vibration signature analyses testing; Rebuild degraded components	
Maintenance and Replacement Activities	(not provided)	Operator Error, Incorrect Replacement Materials	Use Optimum Innovative Tools, Equipment, and Procedures	

A guideline of criteria was developed for the urgency of CRDM replacement based upon plant questionnaire responses (Greene 1992):

Priority 1 CRDMs - Must be exchanged or rebuilt if the following occur

1. Excessive scram times
2. CRDM does not fully insert during a scram
3. CRDM has a history of uncoupling
4. CRDM will not fully withdraw
5. CRDM consistently has a withdrawal stall flow great than 5 gpm

Priority 2 CRDMs - Should be exchanged or rebuilt

1. Consistently high temperatures (>177°C(>350°F)) throughout length of travel
2. Unacceptable withdrawal or insertion times (unrelated to HCU)
3. Repeated episodes of "double-notching" when moving, or CRDMs that continually require increased drive pressures to move (unrelated to HCU)
4. CRDMs with high or abnormal friction traces (not attributable to misalignment with fuel assemblies).

Boiling-water reactors are subject to the same ASME Code inspection requirements as PWRs. In addition to the ASME visual inspections, other testing methods, not mandated by law, have proven effective in assessing system operability and performance. The leak-rate and stroke tests check rebuilt drives for component problems prior to insertion in the reactor vessel. Leaks are discovered by running hydraulic fluid through the drive while the stroke test determines if the CRDM will protract under normal design pressures. Stall flow tests, both insert and withdrawal, estimate the degree of seal degradation by measuring in-situ flow rates. Measured rates can then be trended and compared against maximum limits (e.g., 19 lpm (5 gpm) for withdrawal stall flows) to indicate whether maintenance is necessary. Differential pressure (AP) testing employs electronic test equipment to record piston pressures at test ports in the HCU manifold and high point vent valves. The relationship between piston-over (PO) and piston-under (PU) ΔP values can reveal valve defects in the HCU and extreme drive-line friction in the CRDM (General Electric 1975).

Database management software is available to aid in the acquisition, display, and storage of operational performance data. Historical trends of this data can be analyzed to diagnose operational problems and/or component deterioration. DRIVEX, for example, is a computer program that combines the interactive input of symptoms with the comparison of AP traces (actual vs. reference) to pinpoint the cause of operational problems (General Electric 1990).

Crud, or debris, travels through the coolant, collecting under Graphitar seal sets and clogging filters. Not only does crud degrade the seals, it also accelerates corrosion by abrading and pitting component surfaces. Crud accumulation can be mitigated by 1) flushing the CRDM (General Electric 1976), 2) vacuuming in and around guide tubes during refueling outages, and 3) changing the filters in the normal supply water more frequently.

Better materials and design enhancements should continue to improve CRDM performance. Toshiba, for instance, has developed a new carbon seal ring more resistant to cracking and has modified the design of the inner filter base configuration to avoid control rod uncoupling.

Difficult conditions, such as high temperature, poor visibility, and cramped working areas, frustrate maintenance personnel during CRDM change out. Special training and equipment can improve the efficiency and safety (e.g., radiation exposure) of under vessel operations. Most special training is practiced on mock-up units, which provide valuable, "hands-on" experience for workers (Werres and Thornton 1990). Bubble suits, temporary lighting, portable air conditioners, as low as reasonably achievable (ALARA) shields, and advanced handling tools are all examples of special equipment (Greene 1992).

Other existing technologies that could be considered as management options include 1) an automated inspection system that incorporates ultrasonic, eddy current, and visual inspection techniques from the refueling bridge to examine in-core housings and stub tube welds (Richardson 1990); 2) industrial pyrometers that detect solenoid coil degradation by monitoring and trending surface temperatures; and 3) hydrogen injections that alter water chemistry to minimize IGSCC damage to stub-tube welds.

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3 Reactor Protection System

The Reactor Protection System (RPS) is the principal information-gathering and decision-making system to ensure safe operation of the reactor. To guarantee the integrity of the reactor and to avoid undue risk to the health and safety of the public, an elaborate reactor protection structure is needed. The fundamental purpose of the RPS is to prevent the release of radioactivity into the environment by protecting the fuel and the pressure boundary. To achieve this, the RPS acts to prevent unsafe operation of the reactor, which could lead to accident conditions. The prevention of unsafe operation is accomplished when the RPS initiates a reactor trip to shut down the reactor. The RPS measures critical parameters that describe whether the reactor is operating within a safe performance envelope, alarms when an unsafe performance condition is being approached, and initiates a reactor trip when safe operating limits are exceeded. In the event that an accident does occur, the RPS initiates engineered safety features to prevent further development or deterioration of potentially unsafe conditions in mitigating the severity and consequences of the accident.

Because of its important contribution to plant safety, the RPS is designed, constructed, and tested to meet the highest standards. The system must be able to supply reactor and component trip signals and initiate engineered safety features to provide the required degree of protection for all normal operating and accident conditions. A simplified block diagram of the RPS is shown in Figure 3.1: a typical sensor channel is shown in Figure 3.2. The nuclear and process instrument subsystems send trip signals to the logic trains. There are two complete and independent sets of logic circuits in the RPS cabinets, as shown in Figure 3.3; each set constitutes a logic train. When an unsafe condition is sensed, a signal is sent to the RPS cabinets. If a reactor trip is required, the RPS logic sends a signal to open the reactor trip breakers. Tripping these breakers removes power from the control rod drive mechanisms for Pressurized-Water Reactors, allowing the rods to drop into the reactor core, thus shutting down the reactor. If an engineered safety feature actuation is required, the RPS logic actuates the appropriate safety equipment, depending on plant conditions. Permissive signals are also provided by the logic trains to allow automatic or manually initiated interlocks and bypasses.

There are usually four reactor protection channels with a trip sensor string in each channel. Each of the trip strings also has dual isolated components to provide component redundancy. Only one of the many trip sensors has to actuate to trip the entire channel. Two channels have to trip to cause the entire RPS to trip. This process is called two-of-four logic, and it prevents the accidental tripping of the RPS by a spurious signal in only one channel. The resulting high degree of redundancy of the RPS prevents total system failure while allowing for individual component failures.

3.1 Aging Degradation Concerns and Mechanisms

A number of reviews have been performed on the various individual components that make up the better portion of the Reactor Protection System. Nuclear Plant Aging Research (NPAR) studies of the RPS were conducted by Idaho National Engineering Laboratory (Meyer 1988; Sharma 1992), Oak Ridge National Laboratory (Gehl et al. 1992), and Wyle Laboratories (Gleason 1992). These studies provided the technical basis for the RPS standard technical specifications (STS) aging evaluation. Additional information was obtained from publications by Edson (1992), Gleason (1991a), Gleason (1991b), Hashemian (1991), Husler and Weir (1991), IEEE Standard 1205-1993, Meyer and Edson (1990), and Shah (1987). Data review is presently continuing to update and enhance the available information so that more informed decisions can be made. In the work by Meyer (1988), the components within the RPS have been identified based on materials susceptible to aging. In general, materials most often cited as weak links in terms of aging are electrical insulation, seals and gaskets, and electronic components. In addition, circuit breakers and relays are also susceptible to aging. Below is a brief review of the aging concerns and mechanisms of the RPS components. A summary is provided in Table 3.1.

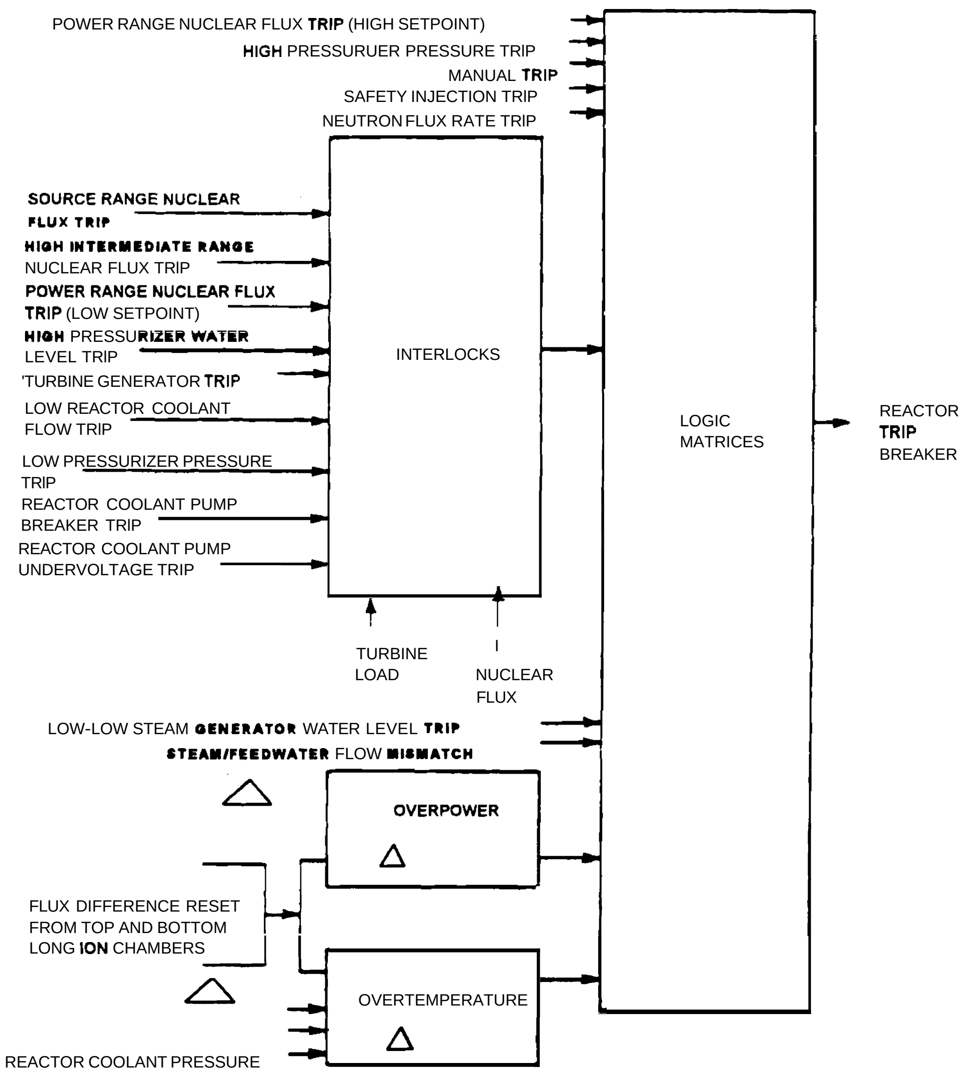

Figure 3.1 Simplified reactor protection system block diagram

The associated components are:

(1) *Sensors and Transmitters* - The important subcomponents in this category are the Pressure Transducers which can be classified as strain gauge type and capacitance type.

(2) *Cables, Connectors, and Terminals* - The subcomponents in this category are Instrument and Coaxial Cables for which the Insulation, Insulation Jacket, and Sheath are most vulnerable to aging.

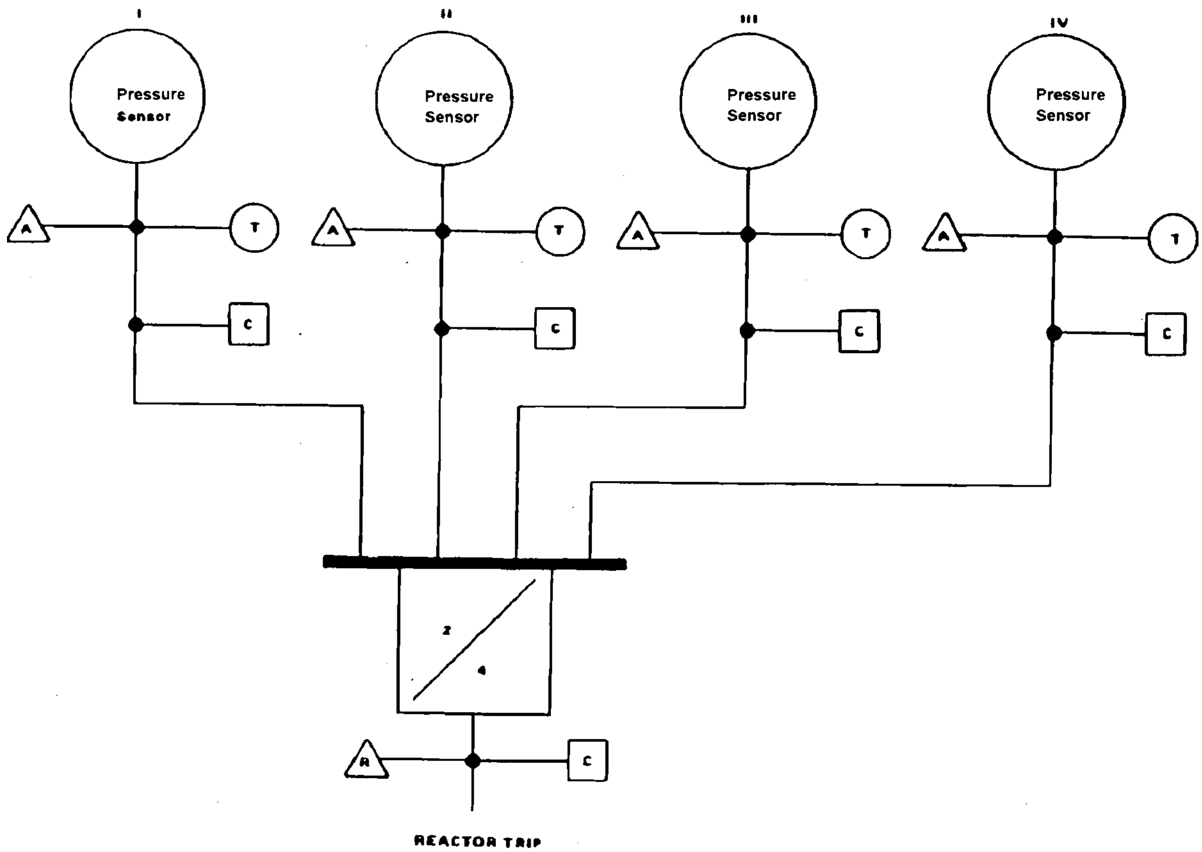

Figure 3.2 Typical reactor protection system sensor channel (pressure)

(3) *Electrical Penetrations* - The subcomponents in this category that are most vulnerable to aging are **1)** Terminal Strip Assembly, **2)** Shrink Tubing, **3)** 0-Ring Seal, **4)** Interfacial Seal, **and** 5) Insulator Plug Skirt.

(4) ***Circuit Breakers* - *The*** mechanical parts are subject to wear due to testing. The failure rate increases for most types after the sixth year of service. Routine maintenance and refurbishment minimize breaker problems.

(5) ***Relays* - *All*** types of relays have problems with vibration and wear. Normally, energized relays fail more often than de-energized relays because of thermally induced damage to the organic coil and housing components.

Reichmanis et al. **(1993)** present the processes and mechanisms of irradiation of polymeric materials.

3.2 Managing Aging Degradation

The aging degradation of the components of the Reactor Protection System can be managed by applying the recommended ISM methods, i.e., periodic visual inspection, calibration, verifying operational characteristics, and by the normal component replacement programs. Too frequent testing is detrimental to the life of many of these components as are stresses caused by human errors such as rough handling or testing with values of current, voltage, pressure, etc., above the acceptable or recommended limits. However, Meyer **(1988)** and Beranek et al. **(1989** p. **30)** suggest that knowledge gained from engineering designs, applications, tests, and operating experience be utilized. Also, data from in situ assessments, condition monitoring, record keeping, and post-service examination and tests are essential for developing suitable deterministic models and for risk assessments , component prioritization, and trending analysis. Such information may allow the detection of sudden component failures before they occur. Table **3.2** summarizes the methods of managing aging degradation and provides references.

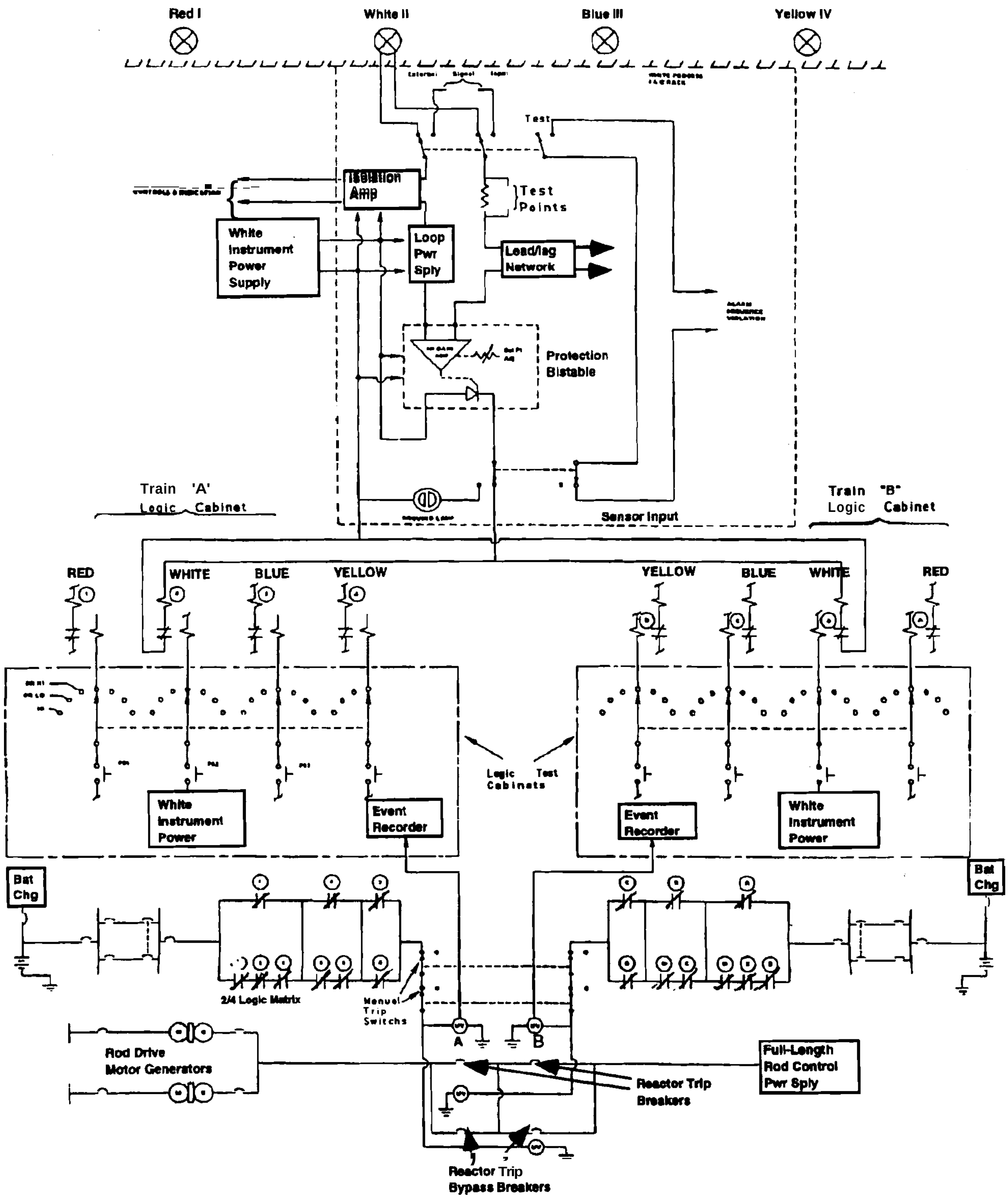

Figure 3.3 Typical RPS channel logic circuit

Table 3.1 Aging concerns and mechanisms in reactor protection systems

Component	Material	Aging Concerns	Aging Mechanisms	References
Sensors/Transmitters				
Printed Circuit Board	Epoxy Glass Laminate	Cracking	Radiation Embrittlement	Meyer 1988, p. **62;** Reichmanis et al. 1993.
Housing Seals	Ethylene	Seal Opening, **Cracking**	Creep, Hardening	Meyer 1988, p. **62.**
Terminal Block	Phenolic	Cracking	Radiation Embrittlement	Meyer 1988, p. **62.**
Housing 0-Rings	EPDM	Interface Pressure Drop	Creep, Hardening	Meyer 1988, p. **62.**
Cables/Connectors				
Insulation	Cross Linked Polyethylene	Leakage Currents	Radiation Aging	Ahmed et al. 1985, p. 38. Jacobus 1990, pp. **27, 41.** Meyer 1988, p. **62.**
Insulation Jacket	PVC	Cracking	Radiation Embrittlement	Reichmanis et al. 1993
Sheath	Neoprene	Cracking	Radiation Embrittlement	Reichmanis et al. 1993
Penetrations				
Terminal Strip Assembly	Glass Filled Phenolic	Cracking	Radiation Embrittlement	Meyer 1988, p. **62;** Reichmanis et **al.** 1993.
Shrink Tubing	Polyolefm	Cracking	Radiation Embrittlement	Meyer 1988, p. **62**
0-Ring Seal	Elastomer	Cracking		
Interfacial Seal	Dow Corning Sylgard	**Seal** Opening, Cracking	Creep, Hardening	Meyer 1988, p. **62**
				Meyer 1988, p. **62**
Insulator, Plug Skirt	Polysulphone	Cracking	Creep, Hardening	
			Radiation Embrittlement	Meyer 1988, p. **62,** **Reichmanis** et al. 1993.
Circuit Breakers		Loss of Operation	Wear, Vibration, Resistive Heating	**Toman** et al. 1987.
Relays		Loss of Operation	Wear, High-Cycle Fatigue	**Toman et** al. 1987.

Table 3.2 Managing aging degradation

Components	Materials	Aging Mechanisms	Management Options	References
Sensors/Transmitters				
Printed Circuit Board	Epoxy Glass Laminate	Radiation Embrittlement	Trend Testing	Meyer 1988, p. 72; Toman 1986, p. 37
Housing Seals	Ethylene	Creep, Hardening	Sampling	Meyer 1988, p. 72
Terminal Block	Phenolic	Radiation Embrittlement	Trend testing	Meyer 1988, p. 72
Housing O-Rings	EPDM	Creep, Hardening	Trend Testing	Meyer 1988, p. 72
Cables/Connectors				
Insulation	Cross-Linked Polyethylene	Radiation Aging	Visual Inspection	Ahmed et al. 1985, p. 38 Jacobus 1990, p. 27,41. Meyer 1988, p. 62
Insulation Jacket	PVC	Cracking	Radiation Embrittlement	Reichmanis et al. 1993
Sheath	Neoprene	Cracking	Radiation Embrittlement	Reichmanis et al. 1993
Circuit Breakers		Loss of Operation	Wear, Vibration, Resistive Heating	Toman et al. 1987.
Relays		Loss of Operation	Wear, High-Cycle Fatigue	Toman et al. 1987.
Penetrations				
Terminal Strip Assembly	Glass filled Phenolic	Cracking	Radiation Embrittlement	Meyer 1988, p. 62; Reichmanis et al. 1993.
Shrink Tubing	Polyolefin	Cracking	Radiation Embrittlement	Meyer 1988, p. 62;
0-Ring Seal	Elastomer	Cracking	Creep, Hardening	Meyer 1988, p. 62;
Interfacial Seal	Dow Corning Sylgard	Seal Opening, Cracking	Creep, Hardening	Meyer 1988, p. 62;
Insulator, Plug Skirt	Polysulphon	Cracking	Radiation Embrittlement	Meyer 1988, p. 62; Reichmanis et al. 1993.

3.3 References

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4 Standby Liquid Control System (BWR)

The Standby Liquid Control (SLC) system is a backup reactivity control system that is unique to General Electric BWR designs. If a BWR experiences an anticipated transient without scram (ATWS) event, where control rods cannot be inserted into the reactor and heat is being added to the suppression pool, the emergency operating procedures will dictate that the SLC system be initiated. If action is not taken to control reactor power under these conditions, it is possible that the heat capacity limit of the primary containment could be exceeded and the primary containment integrity could be challenged. The SLC system will inject sodium pentaborate solution into the reactor vessel as the reactivity control agent. It is injected into the bottom of the core where it mixes with the reactor coolant. Sodium pentaborate contains boron-10, which has a high absorption cross section for thermal neutrons (Walker et al. 1983).

The SLC system consists of a stainless steel storage tank, a pair of full capacity positive displacement pumps, two motor-operated suction valves, two explosive actuated discharge valves, and the necessary valves and associated piping and instrumentation to inject the sodium pentaborate into the reactor vessel. In addition, the system includes a test tank with the necessary valves and piping to adequately test system performance by injecting demineralized water instead of sodium pentaborate into the RPV. A simplified one-line diagram of the SLC system is shown in Figure 4.1. Some facility systems have accumulators, located on the SLC pump discharge lines, designed to dampen the pressure pulsation from operation of the positive displacement pumps.

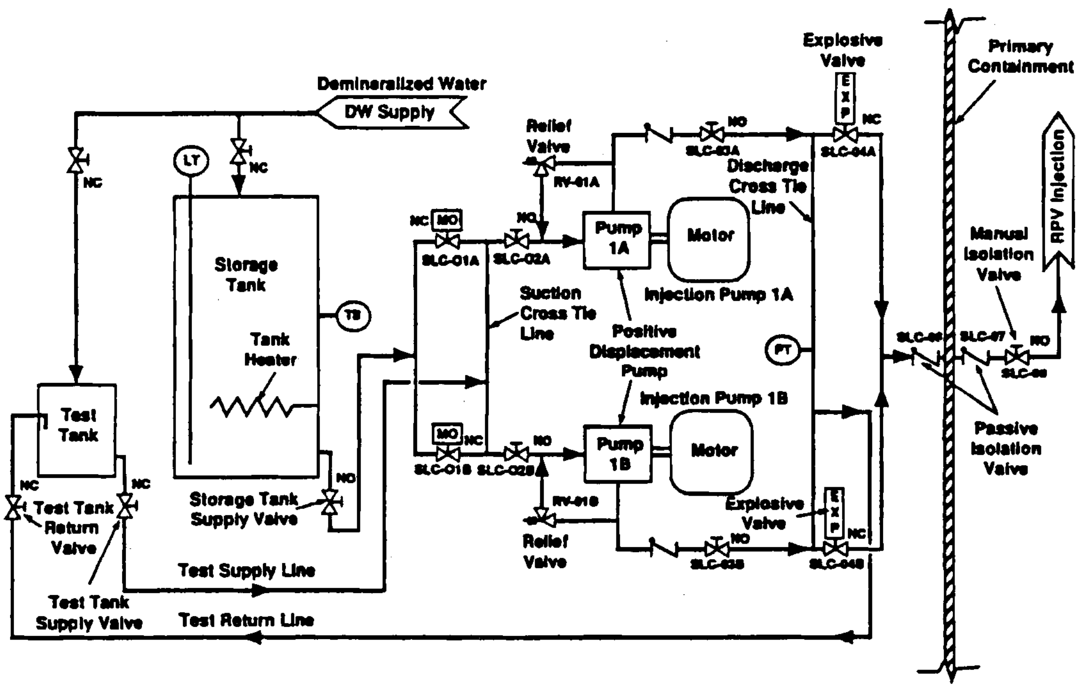

Figure 4.1 Typical standby liquid control system

The sodium pentaborate is stored in the storage tank and is maintained at a specific temperature, tank level, and concentration to ensure that the minimum shutdown requirement of 660 ppm boron concentration is available to be injected into the **RPV** within a 50- to 125-minute period.

4.1 Aging Concerns and Mechanisms

In the study by Buckley et al. (1992) the SLC system relief valves were identified as the most troublesome component that appeared to be affected by aging. Most relief valve failures were identified as setpoint drift attributed to mechanical wear. There were a few relief valve failures linked to sodium pentaborate build up and corrosion. Relief valve failure was a concern because the relief valve must work properly for the system to be reliable.

The study noted some other components that were affected by aging: pumps, accumulators, and the system instrumentation. The types of aging concerns that were found in these components did not result in significant system failures. Table 4.1 summarizes the aging concerns and mechanisms identified by the study.

Concerns were also raised that stainless steel components that are exposed to borated media could cause SCC in stainless steel components exposed to that environment. The cracking is suspected to be linked to the concentration of chlorides and sulfates that contaminate the media. The Buckley et al. (1992) study found no evidence that this type of stress corrosion cracking existed in the SLC system; however, continued study is recommended.

4.2 Managing Aging Degradation

Table 4.2 summarizes the recommended methods to manage and mitigate the aging concerns.

To manage the aging issues of the system relief valves, the Buckley et al. (1992) study recommends that the surveillance interval for testing the valves become more frequent, at least once every refueling outage, so that the setpoint drift problem can be closely monitored.

The pumps, accumulators, and instrumentation are subject to aging primarily due to normal wear. Current surveillance intervals and techniques appear to be adequate.

Table 4.1 Aging concerns and mechanisms in SLC xystems

Component	Material	Aging Concerns	Aging Mechanisms	References
Relief Valves	Stainless Steel	Setpoint Drift Leading to Reduced Boron Injection	Wear, Corrosion	Buckley et al. (1992)
Pumps	Stainless Steel	Degradation of Seals, Internal Check Valves, and Pump Packing	Wear	Buckley et al. (1992)
Accumulators	Stainless Steel	Failure to Maintain Nitrogen Gas Pressure Due to Failure of Nitrogen Gas Bladder	Wear	Buckley et al. (1992)
Instrumentation and Control	(not applicable)	Setpoint Drift Leading to Reduced Boron Injection	Wear	Buckley et al. (1992)

Table 4.2 Managing aging degradation of SLC systems

Component	Material	Aging Mechanisms	Management Options	References
Relief Valves	Stainless Steel	Wear, Corrosion	Increase Surveillance Interval and Monitor for Setpoint Drift	Buckley et al. 1992
Pumps	Stainless Steel	Wear	Maintain Normal Maintenance and Durveillance Practice	Buckley et al. 1992
Accumulators	Stainless Steel	Wear	Maintain Normal Maintenance and Surveillance Practice	Buckley et al. 1992
Instrumentation and Control	(not applicable)	Wear	Maintain Normal Maintenance and Surveillance Practice	Buckley et al. 1992

Even though the threat of SCC in the SLC system appears to be minimal, preventive measures are still recommended. Stress corrosion cracking can be managed by monitoring the sodium pentaborate solution for sulfide and chloride contaminants. This type of surveillance should take place upon receipt of the Borax and boric acid ingredients of the sodium pentaborate, and also, periodically, a sample from the solution in the storage tank should be analyzed. Further study should be conducted to determine what levels of sulfides and chlorides would constitute a threat to the SLC system.

4.3 References

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Walker, W. F., D. G. Miller, and F. Feiner. 1983. Chart of the Nuclides, Thirteenth Edition. General Electric Company, San Jose, California.

5 Engineered Safety Systems

The Engineered Safety Systems include the residual heat removal, the high pressure injection, the high pressure coolant injection and the high pressure core spray systems. These systems provide heat removal and/or coolant inventory control in the primary coolant system.

5.1 Residual Heat Removal System

The primary function of the residual heat removal (RHR) system is to transfer heat from the core and reactor coolant system (RCS) during plant shutdown and refueling operations. The system is also employed with the safety injection system for emergency core cooling system (ECCS) under LOCA conditions. The system is designed to perform the following functions:

- to provide core cooling in the unlikely event of a LOCA (this cooling is intended to prevent excessive core heat up, significant cladding-water reactions, fuel melting, or significant alteration of core geometry)
- to limit suppression pool water temperature (in BWRs)
- to remove decay heat and sensible heat from the RCS while the plant is shut down for refueling and servicing
- to condense reactor steam so that decay and residual heat may be removed if the main condenser is not available at hot standby (in BWRs)
- to supplement the fuel and containment pools cooling and cleanup system capacity when necessary to provide additional cooling capability.

The RHR system in PWRs receives water from the RCS hot legs, cools it, and pumps it back to the cold legs or core flooding tank nozzles. The low-pressure RHR system is isolated from the RCS when the reactor coolant pressure is higher than the RHR system design pressure by valves in the RHR pump suction and discharge lines. The heat removed in the heat exchangers is transported by the component cooling water or service water system. The RHR system is also used to fill, drain, and remove heat from the refueling canal during refueling operations, to circulate coolant through the core during plant startup prior to RCS pump operations, and in some cases to provide an auxiliary pressurizer spray.

The RHR system in BWRs typically consists of pumps, valves, heat exchangers, piping, pipe supports and constraints, electrical instrumentation, and controls. The RHR system for a typical BWR plant is shown in Figure 5.1. In the shutdown cooling mode, the BWR RHR system can also be used to supplement spent fuel pool cooling. The low-pressure RHR piping is protected from high RCS pressure by isolation valves. The steam condensing mode of reactor core isolation cooling (RCIC) operation in BWRs (when included in the plant design) provides an alternative to the main condenser or normal RCIC mode of operation during the initial cooldown. Steam from the reactor is transferred to the RHR heat exchangers where it is condensed. The condensate is piped to the suction side of the RCIC pump. The RCIC pump returns the condensate to the reactor vessel. The heat removed in the heat exchangers is transported to the ultimate heat sink by the service water system. An aging assessment of the RCIC system has been performed by Lee (1994).

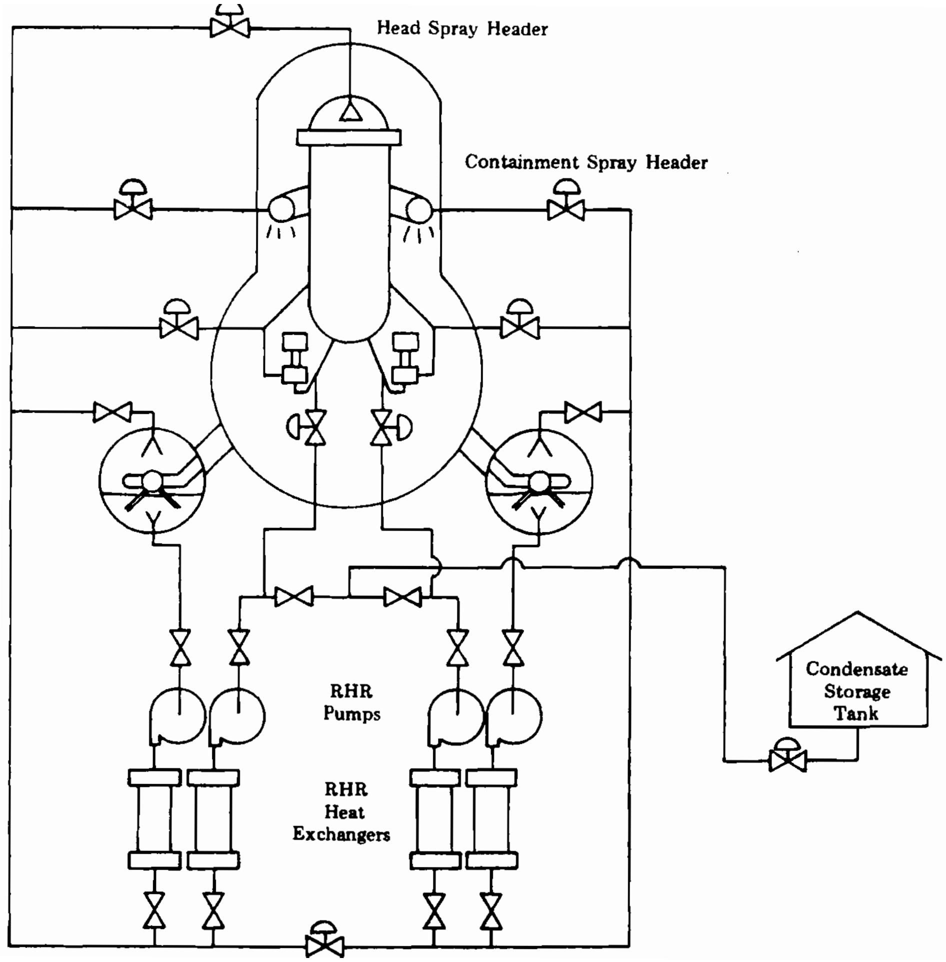

Figure 5.1 RHR system for a typical BWR plant

5.1.1 Aging Concerns and Mechanisms

A large percentage of RHR failures in BWRs is aging related (Lofaro et al. 1989). Many of these failures resulted in degraded operation of the RHR system. The system with a failed component could still perform its functions; however, the failed components eventually required repair or replacement. The dominant failure mechanisms in a BWR RHR system were found to be wear and calibration drift (Lofaro et al. 1989).

The predominant failure mode was leakage in pumps and valves followed by loss of function and erroneous signals in instrumentation and controls. Detailed results on research on valves have been performed by Greenstreet et al. (1985) and Haynes (1989). Key RHR system aging degradation concerns and mechanisms are presented in Table 5.1.

Table 5.1 Aging degradation concerns and mechanisms for RHR systems

Component	Materials	Aging Concerns	Aging Mechanisms	References
Pump Impeller	Stainless Steel	Distortion	Erosion, Corrosion	Lofaro et al. 1989, pp. 2.4, 2.16
Pump Bearing	Carbon Steel	Leakage	Wear, Fatigue	
Pump Seals	Polymeric	Leakage	Creep, Hardening	
Pump Casing	Carbon Steel	Leakage	Wear	
Valve Seal (packing)	Asbestos	Leakage	Wear	Lofaro et al. 1989, p. 2.16
Valve Body	Stainless Steel	Thinning	Corrosion	
Valve Seat	EPDM	Leakage	Wear	
Valve Internals	Stainless Steel	Distortion	Erosion, Corrosion	
Heat Exchanger Tubesheet	Stainless Steel	Thinning	Corrosion, Erosion	Lofaro et al. 1989
Heat Exchanger Channel Head	Carbon Steel	Thinning	Corrosion, Erosion	
Heat Exchanger Tubes	304L Stainless Steel or CuNi	Fouling, Blockage, Leakage	Corrosion, Debris, Erosion, Wear	
Instrumentation and Control	(not applicable)	Calibration Drift		Lofaro et al. 1989, p. 4.14

5.1.2 Managing Aging Degradation

An effective approach to managing aging degradation must include a preventive maintenance program that periodically tests, monitors, and inspects RHR components to detect degradation and provide criteria for repairs and replacement prior to failure. Programs that develop data from testing for trending analyses should be implemented (Lofaro et al. 1989). These should include periodic valve stroke time as well as pump bearing temperature and vibration. Pump and valve control circuits must be tested periodically to demonstrate functionability. Leaks are detected by visual inspections. Some management options for mitigating aging degradation of RHR systems through inservice inspections are listed in Table 5.2.

5.2 High Pressure Injection System (PWR)

The high pressure injection system (HPIS) in a PWR is part of the ECCS and is shown in Figure 5.2. It provides high pressure injection of borated water from the borated water storage tank (BWST) to prevent uncovering the core for small LOCAs and to delay uncovering the core for intermediate sized LOCAs.

High-head centrifugal motor-driven pumps inject borated water into the cold-leg piping. The HPIS can also be used to cool the core following a reactor shutdown when heat cannot be removed by the steam generator. 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. Some plants use the HPIS system for normal primary coolant system charging and seal injection water for the reactor coolant pumps. Motor operated valves and check valves regulate the flow.

The low pressure injection system (LPIS) is part of the overall ECCS and also pumps borated water from the BWST for long-term core cooling following accident conditions. During the high pressure recirculation mode of operation, the HPIS pumps water from the LPIS output.

The charging inlet nozzles have thermal sleeves that protect the nozzle from thermal shocks.

Table 5.2 Managing aging degradation in RHR systems

Component	Materials	Aging Mechanisms	Management Options	References
Pump Impeller	Stainless Steel	Erosion, Corrosion	Volumetric Inspection	Lofaro et al. 1989, p. 4.3
Pump Bearing	Carbon Steel	Wear, Fatigue	Trend Bearing Temperature, Lubricant Pressure	
Pump Seals	Polymeric	Creep, Hardening	Trend Differential Pressure, Pump Power	
Pump Casing	Carbon Steel	Wear	Volumetric Inspection	
Valve Seal (Packing)	Asbestos	Wear	Monitor Leakage	Lofaro et al. 1989, p. 4.5
Valve Body	Stainless Steel	Corrosion	Visual Inspection	
Valve Seat	EPDM	Wear	Monitor Bolt Torque	
Valve Internals	Stainless Steel	Erosion, Corrosion	Minimize Water Hammer	
Heat Exchanger Tubesheet	Stainless Steel	Corrosion, Erosion	Visual Inspection	Lofaro et al. 1989, p. 4.9
Heat Exchanger Channel Head	Carbon Steel	Corrosion, Erosion	Visual Inspection	
Heat Exchanger Tubes	304L Stainless Steel or CuNi	Corrosion, Debris, Erosion, Wear	Trend Flow, Flow Resistance	
Instrumentation and Control	(not Applicable)	--	Recalibrate	Lofaro et al. 1989, p. 4.12

5.2.1 Aging Concerns and Mechanisms

The HPIS system consists of pumps, valves, instrumentation and controls, and high-pressure piping capable of delivering borated water to the reactor core. The most frequent age-related failures are electrical and mechanical control malfunctions for pumps and valves. Boron crystallization from leaking packing and seals or faulty heat tracing has caused valves and pumps to malfunction. Borated water leaking on to carbon steel parts of HPIS components and on to adjacent systems has caused corrosion. The potential for fatigue failure of the stainless steel pipe and nozzles resulting from loose thermal sleeves or valve seat leakage is of special concern.

Aging degradation is a significant concern in HPIS systems, because failure of certain components would make the systems unavailable. The most common general failure modes are leakage and failure to operate as designed. Key HPIS system aging degradation concerns and mechanisms are listed in Table 5.3. The most commonly failed components are nozzles and thermal sleeves, valves, valve operators, instrumentation and control components, pumps, pipe supports, and pipes. The mechanisms causing these failures include wear aggravated by improper lubrication, corrosion, erosion, fatigue caused by vibration and operation cycles, thermal and radiation embrittlement, water hammer, setpoint drift, and out-of-calibration instrumentation (Meyer 1989). The degradation mechanisms associated with the charging nozzles and safety injection nozzles have been indicated by Shah and MacDonald (1993).

Operability of the LPIS is essential to provide borated water to the HPIS during the high pressure recirculation mode of operation. Because the LPIS also consists of pumps, valves, and piping, its aging degradation mechanisms are similar to those affecting the HPIS. Debris, paint flakes, or loose material due to aging could potentially damage both the LPIS and HPIS during the high pressure recirculation mode of operation.

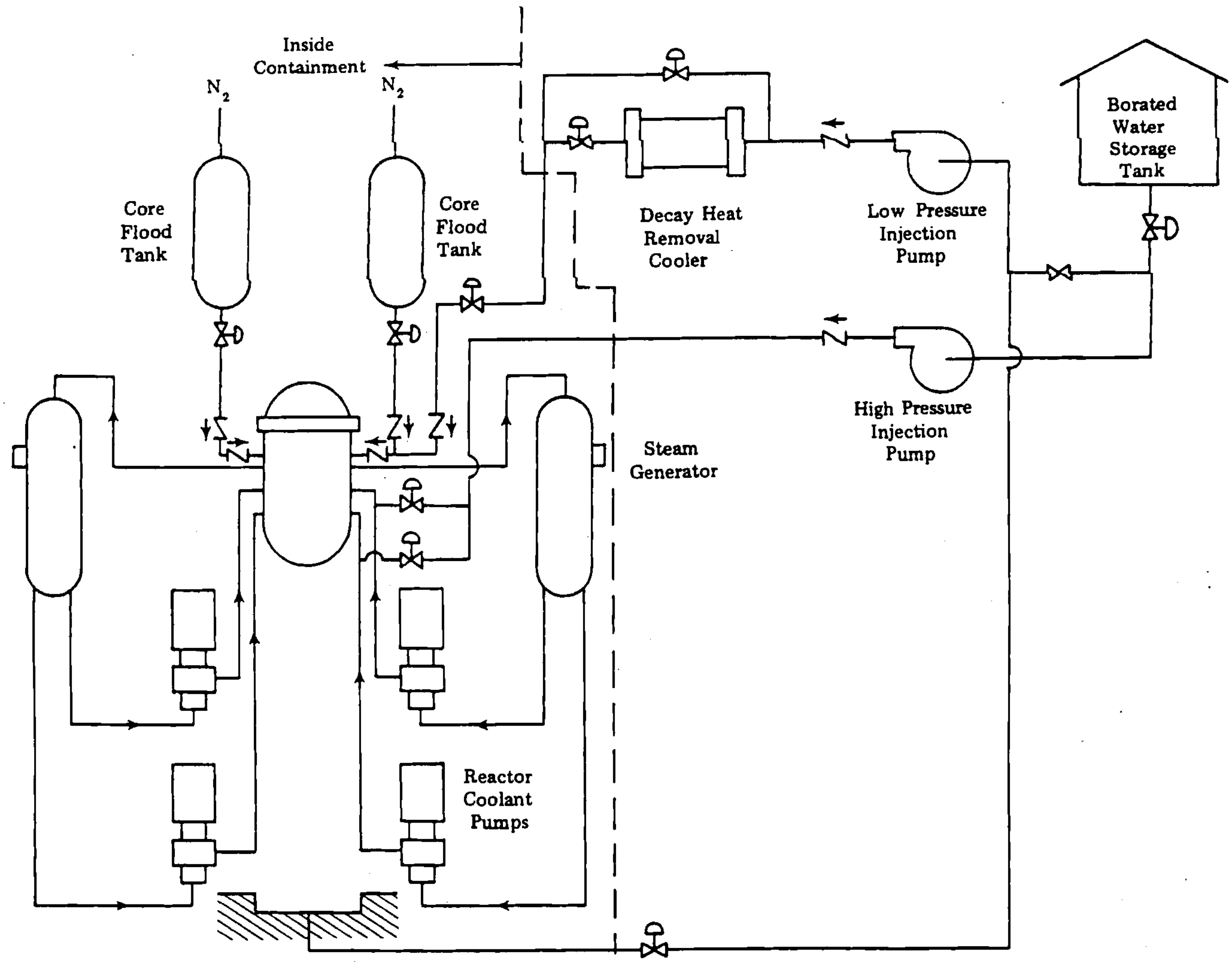

Figure 5.2 High-pressure injection system for a typical PWR plant

Table 5.3 Aging degradation concerns and mechanisms for HPI systems

Component	Materials	Aging Concerns	Aging Mechanisms	References
Nozzles	Low Alloy Steel	Through-wall Cracking, Leakage	Thermal Fatigue	Meyer 1989, p. 36; Shah and MacDonald 1993, p. 241
Thermal Sleeves	Stainless Steel, Ni-Cr Alloy	Loose, Broken Thermal Sleeves	Thermal Fatigue, Vibration	
Valve Seal	Asbestos	Leakage	Wear	Meyer 1989, p. 36
Valve Body	Stainless Steel	Thinning	Wear	
Valve Seat	Polymeric	Leakage	Corrosion	
Valve Internals	Stainless Steel	Distortion	Wear	
Instrumentation and Control		Calibration Drift		Meyer 1989, p. 36
Pump Impellers	Stainless Steel	Distortion	Wear	
Pump Bearings	Carbon Steel	Leakage	Wear, Vibrations, Fatigue	Meyer 1989, p. 36
Pump Seals	Polymeric	Leakage	Wear, Fatigue	

5.2.2 Managing Aging Degradation

An effective approach to managing aging degradation must include a preventive maintenance program that periodically tests, monitors, and inspects HPIS components to detect degradation and provide criteria for repairs and replacement prior to failure. Pump and valve control circuits must be tested periodically to demonstrate functionability. Leaks are detected by visual inspections; prompt repair prevents aggravation of problems from boron crystal build-up in pumps and valves and boric acid corrosion of carbon steel parts. Operating practices that reduce thermal cycling will reduce cracking of pipes and nozzles from thermal fatigue; thermal sleeve integrity and valve leakage must also be monitored. Detection of cracking in welds and high stressed areas of base metal requires enhanced ultrasonic testing. Some management options for mitigating aging degradation of HPIS systems through inservice inspections are listed in Table 5.4. These have been indicated by Meyer (1989). The in-service inspection methods for charging and safety injection nozzles are outlined in Shah and MacDonald (1993).

5.3 High Pressure Coolant Injection System (BWR)

The high pressure coolant injection (HPCI) system is part of the ECCS in a BWR and is an engineered safety feature (ESF). The HPCI system is found in the BWR-3 (except Millstone 1) and BWR-4 designs (Conley et al. 1994). The purpose of the HPCI system is to 1) maintain adequate reactor vessel,water inventory for core cooling on small break LOCAs, 2) depressurize the reactor vessel to allow the low pressure ECCS system to inject on intermediate break LOCAs, and 3) back up the RCIC system or isolation condenser.

The HPCI system is an independent ECCS requiring no AC power, plant service and instrument air, or external cooling water systems to perform its purposes. The HPCI system is normally aligned to remove water from the condensate storage tank and pump the water at high pressure to the reactor vessel via the feedwater piping. HPCI consists of a steam turbine, turbine pump, valves, high pressure piping, two water sources, and instrumentation.

5.3.1 Aging Concerns and Mechanisms

Aging degradation is a significant concern in the ECCS systems, because failure of certain components would make the system unavailable. The most common general failure modes are leakage and failure to operate as designed. Key HPCI system aging degradation concerns and mechanisms for HPCI systems are listed in Table 5.5.

Table 5.4 Managing aging degradation in HPI system

Component	Materials	Aging Mechanisms	Management Options	References
Nozzles	Low Alloy Steel	Thermal Fatigue	Surface and Volumetric Inspections	Meyer 1989, p. 36; Shah and MacDonald 1993, p 241
Thermal Sleeves	Stainless Steel, Ni-Cr Alloy	Thermal Fatigue, Vibration	Volumetric Examination of Welds, Loose Parts Monitoring	
Valve Seal	Asbestos	Wear	Operational Tests	Meyer 1989, p. 36
Valve Body	Stainless Steel	Wear	Visual Inspection	
Valve Seat	Polymeric	Corrosion	Operational Tests	
Valve Internals	Stainless Steel	Wear	Visual Inspection	
Instrumentation and Control	--	--	Test, Recalibrate	Meyer 1989, p. 36
Pump Impellers	Stainless Steel	Wear	Visual Inspection	Meyer 1989, p. 36
Pump Bearings	Carbon Steel	Wear, Vibrations, Fatigue	Testing	
Pump Seals	Polymeric	Wear, Fatigue	Testing	

Table 5.5 Aging degradation concerns and mechanisms for HPCI systems

Component	Materials	Aging Concerns	Aging Mechanisms	References
Valve Seal	Asbestos	Leakage	Wear	Conley et al. 1994, Tables 2 and 37
Valve Body	Alloy Steel	Thinning	Wear	
Valve Seat	Polymeric	Leakage	Corrosion	
Valve Internals	Stainless Steel	Distortion	Wear	
Instrumentation and Control	Polyethylene, Copper	Calibration Drift	Corrosion, Embrittlement	
Pump Impellers	Stainless Steel	Distortion	Wear	
Pump Bearings	Cast Iron	Leakage	Wear, Vibration, Fatigue	
Pump Seals	Polymeric	Leakage	Wear, Fatigue	
Pump Casing	Cast Iron	Leakage, Cracks	Corrosion, Wear	
Turbine Core	Carbon Alloy Steel	Leakage	Wear, Fatigue	
Turbine Impeller	Carbon Alloy Steel	Distortion	Wear, Fatigue	
Turbine Shaft	Carbon Alloy Steel	Cracking	Fatigue	

The most commonly failed components are valves, valve operators, instrumentation and control components, pumps, turbines, piping, and pipe supports. The mechanisms causing these failures include wear aggravated by improper lubrication, corrosion, erosion, fatigue caused by vibration and operation cycles, thermal and radiation embrittlement, water hammer, setpoint drift, and out-of-calibration instrumentation (Conley et al. 1994).

The emergency core cooling system standby safety systems are frequently tested to ensure operability; however, testing and maintenance often cause many of the same stressors as normal operation. These tests may contribute to premature failures, wear, and aging degradation in some components. Other aging stressors also active during system standby conditions may act synergistically to degrade components. A single failure of the pump assembly, the turbine, the flow controller, or any one of several valves will render the system inoperable. Any aging degradation occurring in these components should be monitored and mitigated wherever possible to prevent system inoperabiity to an automatic- or manual-initiation signal.

5.3.2 Managing Aging Degradation

Some management options for mitigating aging degradation of HPCI systems through in-service inspections are listed in Table *5.6*. Most of the ECCS is covered by the ASME Section XI (ASME 1992) code rules for Class 2 systems (i.e., Subsection WC), although the piping up to the first isolation valve is covered by the rules for Class 1 components (i.e., Subsection IWB), and some RCIC system components may also be covered by the ASME code rules for Class 3 systems (i.e., Subsection IWD). Pressure retaining welds in ECCS vessels must be examined volumetrically at each inspection interval, and nozzles in vessels greater than ½ inch (1.27 cm) nominal thickness must be examined by either surface, volumetric, or both methods (depending on the specific weld configuration) during each inspection interval. During normal plant operation, much of the RCIC system contains static water, and portions of the RHR system may contain static water. Hence, the potential for corrosion is such that spot checks of the accessible internal surface areas should be conducted during the later service years to verify the absence of corrosion products and other evidence of deterioration.

Most failures were detected during testing and operations. Maintenance accounts for nearly 14% of the detected failures in HPCI systems. The high percentage of failures detected during surveillance testing and operation is an indication that only a very small number of failures are identified during preventive maintenance before they cause a system malfunction (Conley et al. 1994). Additional information on trending degradation in pumps is provided by Guy (1992). Hoyle (1992) discusses the comprehensive test and other considerations for pump testing. Stockton (1992) examines problems associated with in-service testing of pumps. Haynes (1992) discusses several diagnostic techniques developed at Oak Ridge National Laboratory (ORNL) for monitoring pumps and valves.

Table 5.6 **Managing aging degradation** in **HPCI systems**

Component	Materials	Aging Mechanisms	Management Options	References
Valve Seal	Asbestos	Wear	Surveillance Testing	Conley et al. 1994, Tables 2 and 37
Valve Body	Alloy Steel	Wear	Visual Inspection	
Valve Seat	Polymeric	Corrosion	Advanced Diagnostics	
Valve Internals	Stainless Steel	Wear	Visual Inspection	
Instrumentation and Control	Polyethylene, Copper	Corrosion, Embrittlement	Surveillance Testing	
Pump Impellers	Stainless Steel	Wear	Surveillance Testing	
Pump Bearings	Cast Iron	Wear, Vibration, Fatigue	In Service Testing	
Pump Seals	Polymeric	Wear, Fatigue	In Service Testing	
Pump Casing	Cast Iron	Corrosion, Wear	Visual Inspection	
Turbine Core	Carbon Alloy Steel	Wear, Fatigue	Surveillance Testing	
Turbine Impeller	Carbon Alloy Steel	Wear, Fatigue	Visual Inspection	
Turbine Shaft	Carbon Alloy Steel	Fatigue	Surveillance Testing	

The following recommendations are based on the studies by Conley et al. (1994):

- High failure rates and failures found during testing could be reduced by updated preventive maintenance programs that include most recent methods for detecting, monitoring, and controlling aging degradation. Further improvement could be made by upgrading codes and standards to include aging degradation considerations.

- The incidence of water hammer events could be reduced by design and procedure modifications for opening isolation valves and by implementing drain pot, keep-full, void detection, and venting system improvements.

- The wear and aging degradation caused by fast starts could be reduced if the HPCI response time were relaxed to 60 seconds.

- The HPCI system would be running and available for immediate return to full service without a challenging startup if the systems were switched to recirculation to the coolant storage tank after water level recovery has been verified.

- Damage to the pump from deadhead operation could be prevented by modifying the minimum flow valve operating logic to ensure that the valve is open when the pump starts and closes when the pump is not running.

- The service life of motor-operated valve (MOV) power cables could be extended by using cables capable of conducting the locked rotor current, which is much higher than the nameplate full load current.

- Overstressing of valve stem and valve seats could be reduced by not electrically backseating the valves.

- Stress corrosion cracking could be reduced by replacing materials in valves that are susceptible to SCC, such as Type 410 stainless steel bolting and 17-4PH swing arms with high residual stresses.

- HPCI failures could be reduced by as much as 40% by incorporating wear monitoring, improved inspection, systematic troubleshooting, repairing and trending degradation.

- Wear, corrosion, and aging degradation could be reduced if vendor specified lubricants were systematically used.

5.4 High Pressure Core Spray System (BWR)

The high pressure core spray (HPCS) system is part of the ECCS in a BWR and is an ESF. The HPCS system is found in BWR-5 and BWR-6 (Conley et al. 1994). The purpose of the HPCS system is to 1) maintain reactor inventory after small break LOCAs that do not depressurize the RPV, 2) provide spray cooling heat transfer during breaks in which the core is calculated to become uncovered, and 3) act as a backup to the RCIC system that maintains vessel water inventory in the event of a reactor vessel isolation. The flow diagram of a typical HPCS system is shown in Figure 5.3.

The HPCS system employs a keep-full approach for void-prone systems and motordriven, rather than turbinedriven pumps. It has been reliable, but the failure rate may increase with age. It has, however, experienced a higher number of instrument failures and related instrument failure causes such as setpoint drift and being out of calibration.

5.4.1 Aging Concerns and Mechanisms

Aging degradation is a significant concern in the ECCS systems, because failure of certain components would make the system unavailable. The most common general failure modes are leakage and failure to operate as designed. Key HPCS system aging degradation concerns and mechanisms are listed in Table 5.7. The most commonly failed components are valves, valve operators, instrumentation and control components, pumps, turbines, piping, and pipe supports. The mechanism causing these failures include wear aggravated by improper lubrication, corrosion, erosion, fatigue, thermal and radiation embrittlement, water hammer, setpoint drift, and out-of-calibration instrumentation (Conley et al. 1994).

Emergency core cooling system standby safety systems are frequently tested to ensure operability; however, testing and maintenance often cause many of the same stressors as normal operation. These tests may contribute to premature failures, wear, and aging degradation in some components. Other aging stressors also active during system standby conditions may act synergistically to degrade components. A single failure of the pump assembly, the turbine, the flow controller, or any one of several valves will render the system inoperable. Any aging degradation occurring in these components should be monitored and mitigated wherever possible to prevent system inoperability to an automatic- or manual-initiation signal.

5.4.2 Managing Aging Degradation

Some management options for mitigating aging degradation in HPCS systems through inservice inspections are listed in Table 5.8. Most of the ECCS systems are covered by the ASME Section XI code rules for Class 2 systems (i.e., Subsection IWC), although the piping up to the first isolation valve is covered by the rules for Class I components (i.e., Subsection IWB), and some RCIC system components may also be covered by the ASME code rules for Class 3 systems (i.e., Subsection IWD). Pressure retaining welds in ECCS vessels must be examined volumetrically at each inspection interval, and nozzles in vessels greater than ½ inch (1.27 cm) nominal thickness must be examined by either surface, volumetric, or both methods (depending on the specific weld configuration) during each inspection interval.

During normal plant operation, much of the ECCS system contains static water, and portions of the RHR system may contain static water. Hence, the potential for corrosion is such that spot checks of the accessible internal surface areas should be conducted during the later service years to verify the absence of corrosion products and other evidence of deterioration.

Most failures were detected during testing and operations. Maintenance accounts for nearly 14% of the detected failures in HPCSs. The high percentage of failures detected during surveillance testing and operation is an indication that only a very small number of failures are identified during preventive maintenance before they cause a system malfunction (Conley et al. 1994).

The following recommendations are based on the studies by Conley et al. (1994).

- High failure rates and failures found during testing could be reduced by updated preventive maintenance programs that include most recent methods for detecting, monitoring, and controlling aging degradation. Further improvement could be made by upgrading codes and standards to include aging degradation considerations.

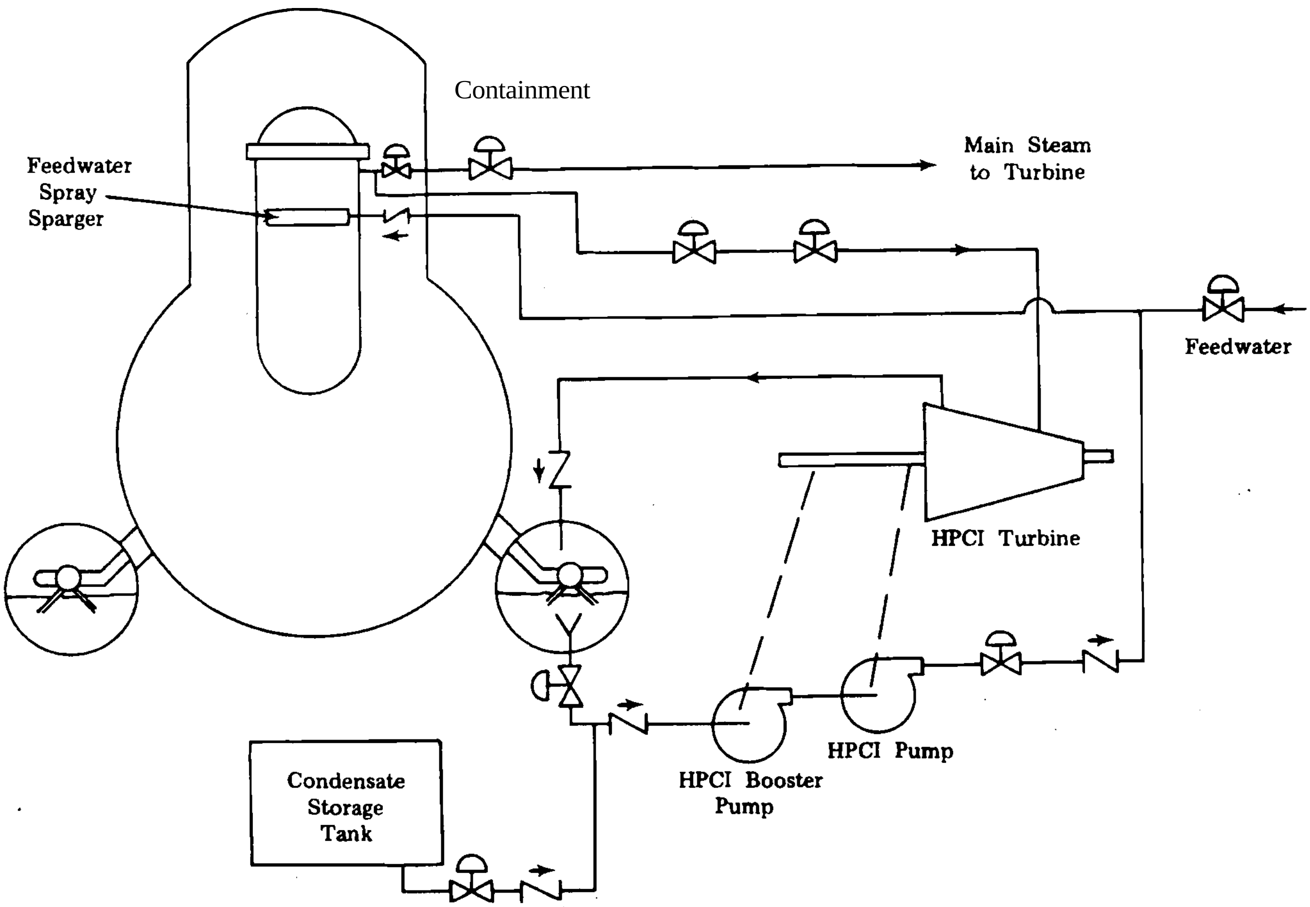

Figure 5.3 Flow diagram of a typical HPCS

- The incidence of water hammer events could be reduced by design and procedure modifications for opening isolation valves and by implementing drain pot, keep-full, void detection, and venting system improvements.
- The wear and aging degradation caused by fast starts could be reduced if the HPCS response time were relaxed to 60 seconds.
- The HPCS would be running and available for immediate return to full service without a challenging startup if the systems were switched to recirculation to the coolant storage tank after water level recovery has been verified.

Table 5.7 Aging degradation concerns and mechanisms for HPCS systems

Component	Materials	Aging Concerns	Aging Mechanisms	References
Valve Seal	Asbestos	Leakage	Wear	Conley et al. 1994, Tables 2 and 37
Valve Body	Alloy Steel	Thinning	Wear	
Valve Seat	Polymeric	Leakage	Corrosion	
Valve Internals	Stainless Steel	Distortion	Wear	
Instrumentation and Control	Polyethylene, Copper	Calibration Drift	Corrosion, Embrittlement	
Pump Impellers	Stainless Steel	Distortion	Wear	
Pump Bearings	Cast Iron	Leakage	Wear, Vibration, Fatigue	
Pump Seals	Polymeric	Leakage	Wear, Fatigue	
Pump Casing	Cast Iron	Leakage, Cracks	Corrosion, Wear	

Table 5.8 Managing aging degradation in HPCS systems

Component	Materials	Aging Mechanisms	Management Options	References
Valve Seal	Asbestos	Wear	Surveillance Testing	Conley et al. 1994, Tables 2 and 37
Valve Body	Alloy Steel	Wear	Visual Inspection	
Valve Seat	Polymeric	Corrosion	Advanced Diagnostics	
Valve Internals	Stainless Steel	Wear	Visual Inspection	
Instrumentation and Control	Polyethylene, Copper	Corrosion, Embrittlement	Surveillance Testing	
Pump Impellers	Stainless Steel	Wear	Surveillance Testing	
Pump Bearings	Cast Iron	Wear, Vibration, Fatigue	In Service Testing	
Pump Seals	Polymeric	Wear, Fatigue	In Service Testing	
Pump Casing	Cast Iron	Corrosion, Wear	Visual Inspection	

- Damage to the pump from deadhead operation could be prevented by modifying the minimum flow valve operating logic to ensure that the valve is open when the pump starts and closes when the pump is not running.
- The service life of MOV power cables could be extended by using cables capable of conducting the locked rotor current, which is much higher than the nameplate full load current.
- Overstressing of valve stem and valve seats could be reduced by not electrically backseating the valves.
- Stress corrosion cracking could be reduced by replacing materials in valves that are susceptible to stress corrosion cracking, such as Type 410 stainless steel bolting and 17-4PH swing arms with high residual stresses.
- HPCS failures could be reduced by as much as 40% by incorporating wear monitoring, improved inspection, systematic troubleshooting, repairing and trending degradation.
- Wear, corrosion, and aging degradation could be reduced if vendor specified lubricants were systematically used.

5.5 References

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6 Auxiliary Feedwater System (PWR)

The auxiliary feedwater system (AFWS) normally supplies high pressure feedwater to the steam generators (**SGs**) during startup, hot standby, and shutdown. It also functions as an emergency system for the removal of heat from the primary system when the main feedwater system is not available for emergency conditions, including small-break LOCA cases. Under certain accident scenarios (involving reactor coolant system-to-secondary coolant system leakage), the AFWS is also supposed to provide a liquid bamer to the **offgas** from the RCS. A schematic drawing of the AFWS is shown in Figure 6.1.

The AFWS operates long enough either to hold the plant at hot standby for several hours or to cool down the primary system, at a rate not to exceed limits specified in technical specifications, to temperature and pressure levels at which the low-pressure decay heat removal system can operate. The AFWS must perform these functions whether or not **offsite** electrical power is available. Consequently, the system contains, in addition to electrical motordriven pumps, a steam **turbine-driven** pump, the steam supply for which are the steam generators themselves.

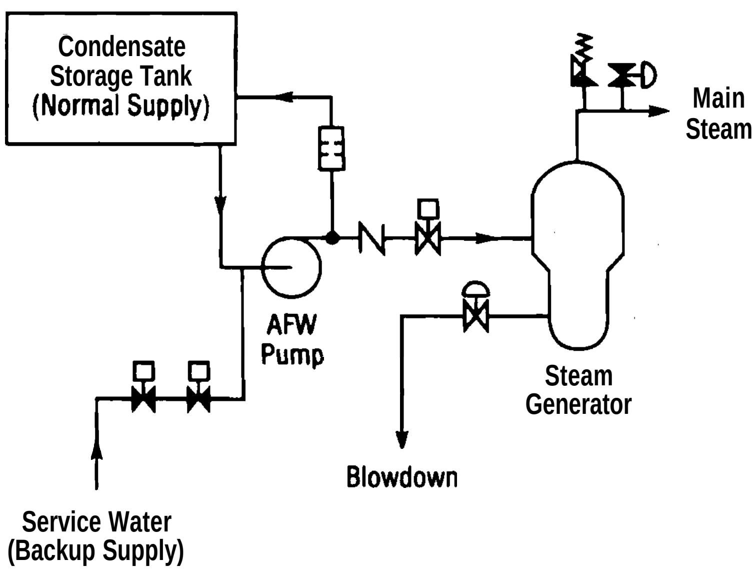

Figure 6.1 Schematic of the AFWS

The water flow boundaries of the AFWS extend from the condensate storage tank (normal operation), to the connections with the steam generators, which are made either through a connection to the main feedwater piping or through separate auxiliary feedwater piping and auxiliary feedwater nozzle connected directly to the steam generators. The AFWS also interfaces with the Engineered Safety Features Actuation System and with the Instrumentation and Control (I&C) and the electrical power systems. All pumps, valves, piping, inter-connections, and cross-connections are included in the AFWS, together with all sensors, manually and automatically actuated control equipment, and the automated feedback/control system for the turbine.

Since July of 1981, the license applicants have included in their license docket the generic short- and long-term recommends-tions identified in NUREG-0611(NRC 1980a) and NUREG-0635 (NRC 1980b) ; an acceptable method for meeting these recommendations is to show, by performing a reliability analysis in accordance with item II.E.1.1 of NUREG-0737 (NRC 1980c), that the AFWS has an unreliability of not greater than 10^{-4} per demand.

6.1 Aging Concerns and Mechanisms

The major aging concerns for the AFWS identified in Casada (1990, 1992) are listed in Table 6.1. The AFWS is essentially a backup system, designed to provide feedwater to the SGs under various accident conditions. The system components are rarely or never tested under the complete set of conditions and demands associated with the accident scenarios. To do so would in some cases be deleterious to other plant systems, under most AFWS/other equipment configurations. Thus, the ovemding aging concern for the AFWS is that wear or degradation might go undetected for components that are rarely tested, or not tested in design demand condition; and that this undetected degradation could cause system failure or functional degradation if the AFWS were called on for its (safety-related) design functions.

The time-related degradation of auxiliary feedwater pumps of PWRs has been addressed in some detail (Adams and Makay 1986; Kitch et al. 1988; Adams 1992) and methods for detecting and monitoring degradation have been reviewed (Kitch et al. 1988).

Table 6.1 Understanding aging of the auxiliary feedwater system

Component	Material	Aging Concerns	Aging Mechanisms	References
Valve Body	Carbon Steel	Wall Thinning	Wear	Casada 1990
Valve Seat	Elastomer	Leakage	Wear	
Valve Internals	Stainless Steel	Leakage	Wear	
Valve Packing	PFTE, Graphite	Leakage	Wear	
Instrumentation and Control Components:	--	Calibration Drift, Failure to Operate	Corrosion, Debris Buildup	
Pump Impeller	Alloy Steel	Cracking, Distortion	Fatigue, Wear	Adams and Makay 1986, p. 50
Pump Diffuser	Stainless Steel	Cracking	Corrosion	
Pump Casing	Cast Carbon Steel, Cast Stainless Steel	Leakage	Wear	
Pump Bearings	Tin-Based Babbitt	Leakage	Wear, Fatigue	
Piping and Piping Connections	Carbon Steel, Low-Alloy Steel	Leakage	Fatigue, Corrosion	
Auxiliary Feedwater Nozzle	Low-Alloy Steel	Cracking	Fatigue, Corrosion	Shah and MacDonald 1993, p. 543

6.2 Managing Aging Degradation

The aging degradation and concerns for specific AFWS components were summarized in the previous section. In this section, the options for better managing the aging for this system are discussed. Options for detecting and/or mitigating aging-related degradation are summarized in Table 6.2.

With regard to flow path maintenance, the most prevalent degradation will be the malfunction of valves in full-flow/flow control demand situations. Nondestructive testing (NDT) methods have now been developed to remotely assess the function and condition of such valves; these methods should be used where practical during routine testing or operation to ensure that the crucial valves are fully operable.

Another aspect of flow path maintenance is piping corrosion and fouling/plugging, especially in little-used piping runs, such as those proceeding to/from the service water system. Modem methods of NDT on such piping runs, combined with modem methods of corrosion and biota control, should be applied to ensure the continued reliability of piping and fittings. This must be supplemented with periodic pressure testing of all critical piping and fittings at the demand pressures.

The fraction of AFWS degradation that has historically been found during demand events, as well as the number and types of failure and degradation sources that were found to not be detectable by the monitoring methods in place at the Reference Plant, indicate the need for improvements in certain aspects of the current monitoring practices. While there are no guidelines to establish what is an acceptable level of failures detected during demand, the rate indicated by the failure data review (about **18%** of all system degradation was detected during demand conditions) appears excessive.

The Reference Plant review also revealed that the ability of some components to function as required under design basis or off-normal conditions is not verified periodically. This was found to be the case particularly where multiple component interaction is involved.

Table 6.2. Managing Aging Degradation of the AFWS

Component	Material	Aging Mechanisms	Management Options	References
Valve Body	Carbon Steel	Wear	Advanced NDT Methods	Kueck **1993**
Valve Seat	Elastomer	Wear	Wear Tracking	
Valve Internals	Stainless Steel	Wear	Wear Tracking	
Valve Packing	PFTE, Graphite	Wear	Wear Tracking	
Instrumentation and Control Components:	--	Corrosion, Debris Buildup	Improved Testing Methods	
Pump Impeller	Alloy Steel	Fatigue, Wear	Established Testing and Maintenance Procedures	Kitch et al. **1988**, p. **71**, Table 5.1
Pump Diffuser	Stainless Steel	Corrosion	--	
Pump Casing	Cast Carbon Steel, Cast Stainless Steel	Wear	--	
Pump Bearings	Tin-Based Babbitt	Wear, Fatigue	--	
Piping and Piping Connections	Carbon Steel, Low-Alloy Steel	Fatigue, Corrosion	–	
Auxiliary Feedwater Nozzle	Low-Alloy Steel	Fatigue, Corrosion	On-line Fatigue Monitoring, Acoustic Emission Monitoring	Shah and MacDonald **1993**, p. 552

Mitigation of these problems involves more comprehensive and better planned periodic testing. Tests must be structured that activate the critical relays and electronics via realistic pseudo signals and, further, verify that the component responses result in appropriate physical changes to the system configuration and permit required operator interactions (e.g., that the crossover and valves respond as advertised).

Kueck (1993) provides recommendations for alternate methods of performing testing that would greatly reduce equipment degradation caused by testing and would improve verification of system operability. The primary areas where alternate test methods are discussed are AFWS pump testing, I&C functional verification, and check valve testing.

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7 Containment Heat Removal System

The containment heat removal systems perform their intended function by controlling pressure and temperature inside the containment. In PWRs, they also assist in fission product cleanup by removing radioactive iodine from the containment atmosphere following an accident in which radiation leakage occurs.

In all PWRs except one (Yankee Rowe), containment cooling is provided by a containment spray system which operates by pumping water through spray nozzles located at the top of the containment structure to cool the containment atmosphere (see Figure 7.1). In most PWRs, containment fan coolers are also provided as a backup to the containment spray system. These fan coolers blow the containment air across cooling coils to remove heat (see Figure 7.2).

With the exception of one plant (Big Rock Point), which uses a dry containment, all BWRs in the United States use a pressure suppression containment. This design includes a large pool of water inside the containment structure, called the suppression pool, and a drywell structure in which the reactor is housed. In pressure suppression containments for BWRs, cooling is provided by a containment spray system (similar to that used in PWRs) to both the drywell and the suppression pool sections along with a suppression pool cooling system (see Figures 7.3 and 7.4). The suppression pool cooling system, is actually an operating mode of the RHR system, the aging issues of which have been discussed in Section 5.1 of this report.

For this study, the definition of containment system used herein limits the systems addressed to those that are required to function to mitigate the consequences of an accident. The containment heat removal systems that operate only during normal plant operation have not been addressed.

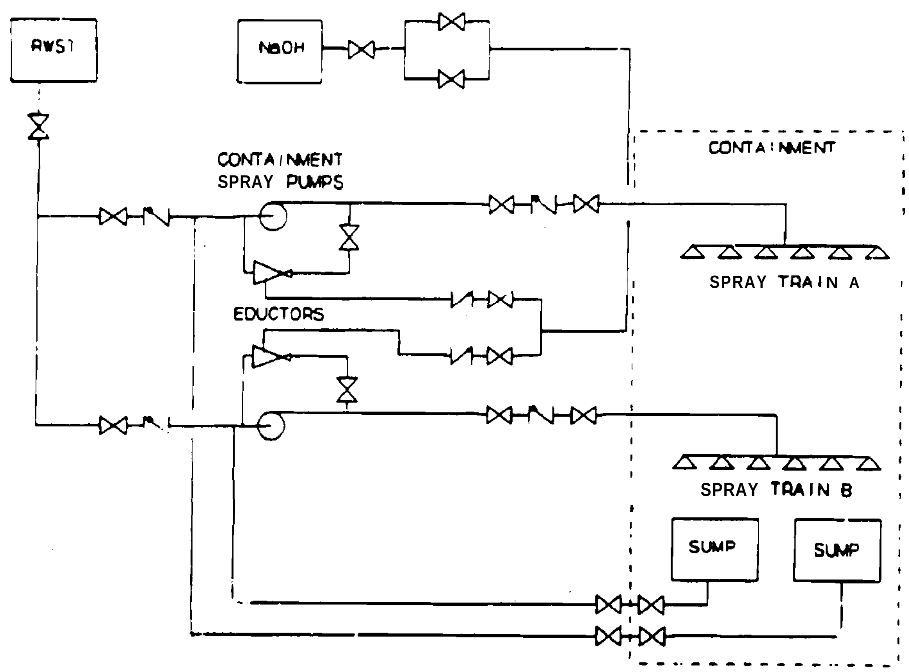

Figure 7.1 Common PWR containment spray system

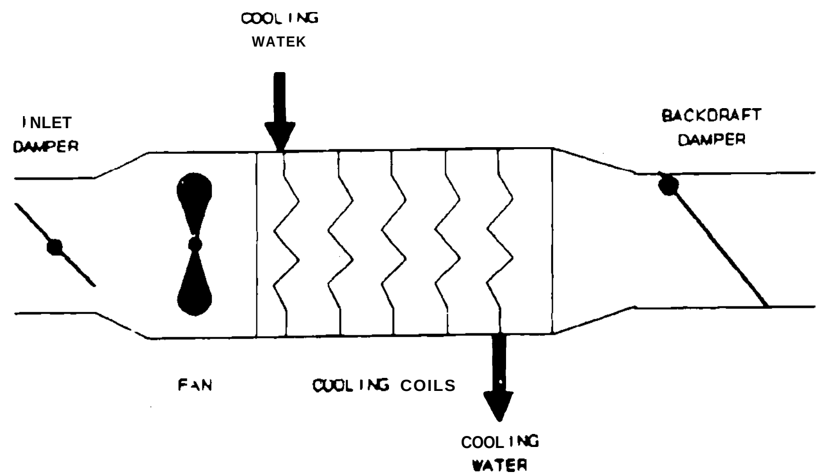

Figure 7.2 Fan cooler schematic

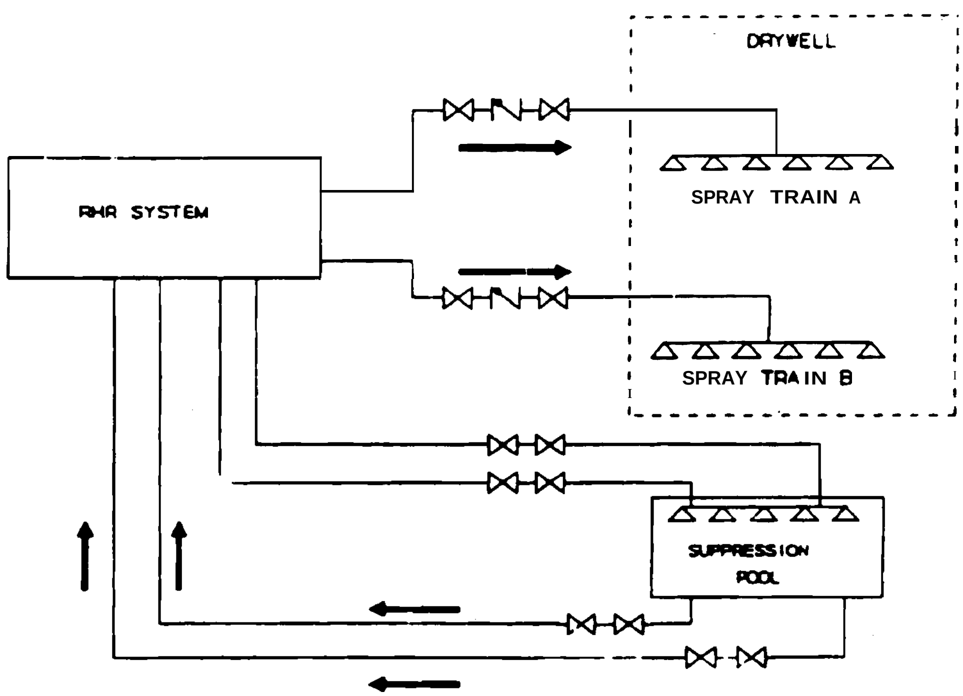

Figure 7.3 BWR containment spray system

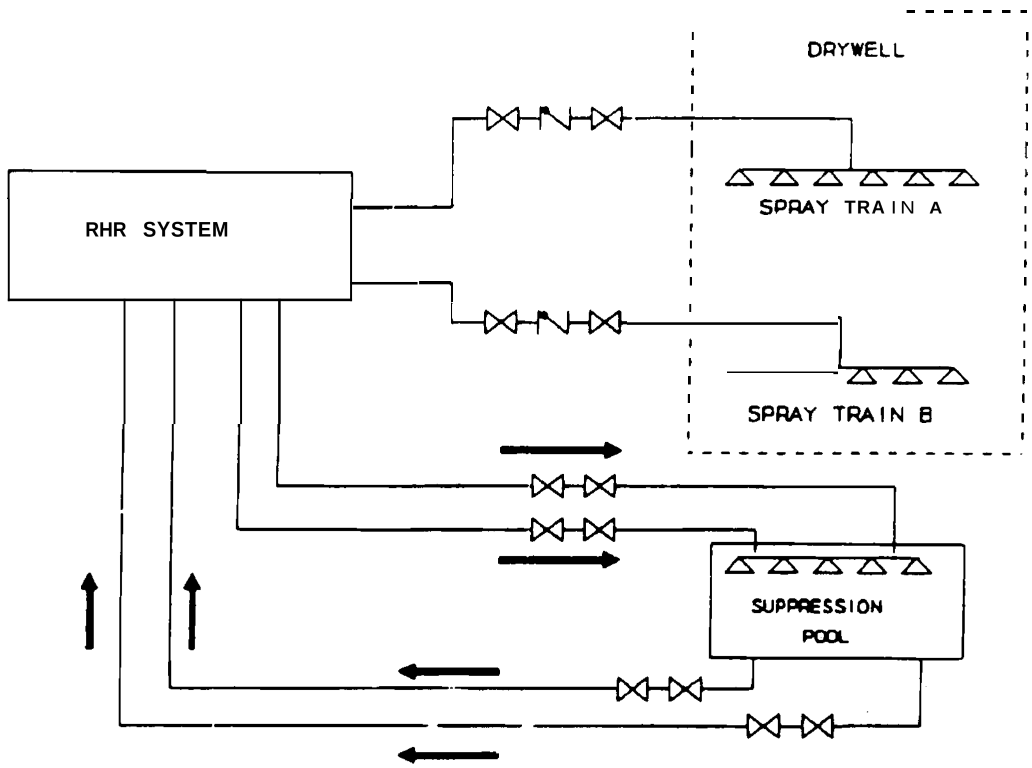

Figure 7.4 BWR suppression pool cooling system

7.1 Aging Concerns and Mechanisms

Meale and Satterwhite (1988) analyzed nuclear plant operational data contained in the Nuclear Plant Reliability Data System (NPRDS) and found that aging was the primary factor in the failure of several fan cooling system components, including circuit breakers, blowers, motors, pumps, and electromechanical controllers. Recently Lofaro et al. (1994) analyzed containment spray systems and fan cooler systems for aging-related failures in both PWRs and BWRs. They showed that environmental stressors (corrosion, erosion, vibration, fatigue, wear, dirt/dust, etc.) contribute significantly to component failure in containment heat removal systems. Table 7.1 summarizes the aging mechanisms and degradations resulting from these stressors for the major components.

7.2 Managing Aging Degradation

The components of a successful program to manage aging degradation are broadly twofold: 1) inservice inspection, surveillance, and monitoring methods (incorporating non-destructive evaluation [NDE] and residual life assessments, where appropriate, as well as parameter trending and record-keeping) to assess the magnitude and rate of aging degradation; and 2) control measures to mitigate the adverse impacts of component aging on plant safety and capacity factors. These methods for managing aging degradation are discussed below and summarized in Table 7.2 for the containment heat removal system.

Lofaro et al. (1994) examined plant-specific data on currently used inservice inspection, surveillance, and monitoring (ISM) methods for containment spray and fan cooler systems. Specifically these include pumps and valves for containment spray systems and valves/dampers and cooling coils for fan cooler systems. The ISM practices are indicated in Table 7.2 for the indicated components. It is to be noted that several of these methods were found to be effective in detecting and mitigating some but not all the aging mechanisms in these systems and improved methods are required (Lofaro et al. 1994, Table 5.4).

Table 7.1 Aging concerns and mechanisms for containment heat removal systems

Component	Material	Aging Concerns	Aging Mechanisms	References
Containment Spray Valve Internals	Stainless Steel	Distortion	Erosion, Corrosion	Lofaro et al. **1994,** Table **3.1**
Containment Spray Valve Packing	PFTE, graphite	Leakage	Wear	-
Containment Spray Valve Seat	Elastomer	Leakage	Wear	
Containment Spray Heat Exchanger Tubes	Copper Nickel Alloy	Plugging, Leakage, Fouling	Debris, Corrosion, Wear	Lofaro et al. **1994,** Table **3.1**
Containment Spray Instrumentation and Control	(not applicable)	Incorrect Signal	Calibration Drift	Lofaro et al. **1994,** Table **3.1.**
Containment Spray Circuit Breakers	Weld Metal	Contact Loss	Wear	Lofaro et al. **1994,** Table **3.1**
Containment Spray Pump Bearing	Cast lron	Leakage	Wear	Lofaro et al. **1994,** Table **3.1**
Containment Spray Pump Seal	Stainless Steel	Leakage	Wear	Lofaro, et al. **1994,** Table **3.1**
Fan Cooler Dampers and Valves	Stainless Steel	Leakage	Wear	Lofaro et al. **1994,** Figures **4.37, 4.38.**
Fan Cooler Instrumentation and Control	(not applicable)	Incorrect Reading	Calibration Drift	Lofaro, et al. **1994,** p. **4-26,** and Figure **4.37**
Fan Cooler Circuit Breakers	(not applicable)	Loss of Contact	Fatigue	Lofaro et al. **1994,** Figures **4.34** and **4.35**
Fan Cooler Cooling Coils	Copper Nickel Alloy	Leakage Plugging, Fouling	Debris, Corrosion, Wear	Lofaro et al. **1994,** Figure **4.40**

Lofaro et al. (1994) recommend a detailed study on determining most effective monitoring and maintenance practices to detect and mitigate aging degradation on containment heat removal system components. Such a study should address the most common types of aging problems exhibited industry wide, and problems specific to certain plant operating conditions.

7.3 References

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Table 7.2 Managing aging degradation of containment heat removal systems

Component	Material	Aging Mechanisms	Management Options	References
Containment Spray Valve Internals	Stainless steel	Erosion, corrosion	• Verify correct position (31 days)	Lofaro et al. 1994, Table 5.1
Containment Spray Valve Packing	PFTE, Graphite	Wear	• Verify stroke time (quarterly/cold shutdown) • Verify full stroke (cold shutdown1 refueling)	. --
Containment Spray Valve Seat	Elastomer	Wear	• Verify relief valve set pressure (5 years) • Venfy automatic valves actuate on hi-hi containment pressure signal (18 mos)	--
Containment Spray Heat Exchanger Tubes	Copper Nickel Alloy	Debris, Corrosion, Wear	Repair or Rreplacement	--
Containment Spray Instrumentation and Control		Calibration Drift	Recalibrate, Replace Worn Parts	--
Containment Spray Circuit Breakers	Weld Metal	Wear	Readjust, Replace Worn Parts	--
Containment Spray Pump bearing	Cast Iron	Wear	• Verify pump head within limits (quarterly) • Verify pump flow within limits (quarterly) • Verify pump vibration within limits (quarterly)	Lofaro et al. 1994, Table 5.1
Containment Spray Pump Seal	Stainless Steel	Wear	• Venfy adequate discharge pressure in recirculation mode (31 days) • Verify pump starts in hi-hi containment pressure signal (18 mos)	Lofaro et al. 1994, Table 5.1
Fan Cooler Dampers and Valves	Stainless Steel	Wear	• Verify automatic operation for operated components (18 mos)	Lofaro et al. 1994, Table 5.2
Fan Cooler Instrumentation and Control		Calibration Drift	Recalibrate, Replace Worn Parts Verify Cooling Water Limits (18 mo) Venfy Pump Head Within Limits (quarterly)	
Fan Cooler Circuit Breakers		Fatigue	Readjust, Replace Worn Parts	
Fan Cooler Cooling Coils	Copper Nickel Alloy	Debris, Corrosion, Wear	Verify No External System Leakage (3 years) Hydro Test (10 years)	Lofaro et al. 1994; Table 5.2

8 Instrument and Control Power Systems

This chapter covers the NPAR activities concerning Batteries, Battery Chargers and Inverters. The first section covers the batteries and the second deals with the chargers and inverters.

8.1 Batteries

Batteries are used in NPPs to provide an emergency power source to vital safety-related functions in the event of AC power loss. The power is delivered directly to critical DC loads or, via DC-to-AC inverters, to critical AC loads such as emergency diesel generator (EDG) starter motors, circuit breakers. control relays, annunciators, and safety-related instrumentation (Berg, Shao, et al. et al. 1994). If there is a station blackout (all offsite power is lost and the EDGs do not start), safe shutdown is possible by battery-supplied power to equipment which monitors and controls plant parameters. These batteries consist of many individual Pb-acid storage cells connected together by flat plates with Pb-Ca grids. Other types of cells, such as Pb-Sb or Ni-Cd, are used in only a few nuclear plants and are not considered in this subsection. During normal operation, the batteries are kept fully charged by the battery charger, which also supplies power to the DC subsystem.

8.1.1 Aging Concerns and Mechanisms

Batteries are subjected to a variety of electrical, mechanical, thermal, chemical, electrochemical and environmental stressors that contribute to battery degradation. Table 8.1 tabulates these stressors along with the affected components, aging concerns, and aging mechanisms.

According to Berg, Shao, et al. (1994), the predominant aging mechanisms are 1) material chemical changes, 2) corrosion, 3) fatigue, 4) wear, 5) thermal aging, 6) gassing and electrolyte evaporation, and 7) fouling. Material chemical changes, often due to the presence of contaminants, are caused by chemical reactions with susceptible components. Corrosion of subcomponents, both metallic and organic, results from long-term exposure in oxidizing environments. Cyclic loading and temperature fluctuations can both initiate and propagate cracks in materials by fatigue cracking. Gradual material loss occurs in valve-regulated batteries by the wear of contacting parts, particularly pressure relief valves. Thermal aging embrittles non-metallic and weakens the dielectric strength of insulating materials. Electrolytic water can be lost by evaporation or an overcharge induced decomposition. The latter phenomenon, called gassing, generates oxygen which can loosen the active materials in the plates and diminish battery capacity. Fouling refers to the accumulation of dust or dirt on electrical equipment that may resist, short circuit, or ground the flow of current.

An example of corrosive degradation is the thermally induced oxidation of grids and top conductors. This oxidation stresses the container by plate swelling, producing electrolyte leakage through newly formed cracks and an increased susceptibility to vibration, as in a seismic event (Edson and Hardin 1987).

8.1.2 Managing Aging Degradation

Table 8.2 contains aging management guidelines for all of the components. The recommended aging management programs and techniques were derived from a survey of 6 utilities covering 17 plants (Berg, Shao, et al. 1994). From this survey the programs were evaluated for effectiveness and divided into two groups. Only the first group, commonly used aging management techniques, will be described in this section. Requirements for maintenance, testing, and replacement of batteries are provided in IEEE Std 450-1987 (IEEE 1987) and Regulatory Guide 1.129 (NRC 1978a). Batteries maintained according to the practices recommended in these two documents should provide reliable service for their qualified life (Edson 1990).

Table 8.1 Aging concerns and mechanisms for batteries'

Component	Material	Applicable Stressors	Aging Concerns	Aging Mechanism
Plates, Grid, Active Material	Lead/Lead-Calcium/ Lead-antimony1 Lead Dioxide	Normal Charging, Overcharging, Undercharging, Impurities, Charge/Discharge Cycles. Seismic Events	Loss of Active Material, Reduced Capacity, Battery Failure	Material Chemical Changes, Corrosion, Fatigue, Gassing
Electrolyte	Sulfuric Acid	Undercharging, Overcharging, Impurities, Elevated Temperature	Reduced Capacity	Material Chemical Changes, Gassing, Electrolyte Evaporation
Separator	Rubber/Glass Mat or Microporous Polyethylene	Overdischarging, Overcharging, Excessive ac Ripple. Elevated Temperature	Internal Short Circuits, Reduced Capacity, Battery Failure	Material Chemical Changes, Thermal Aging
Container	Polycarbonate, Styrene Acrylenitrite, Butadiene Styrene	Improper Cleaning Solvents, Plate Growth. Handling, Elevated Temperature	Cracked Container, Electrolyte Leakage, Reduced Capacity	Material Chemical Changes, Fatigue, Thermal Aging
Top Conductor1 Straps	Lead Alloy (sometimes with copper)	Normal Charging, Overcharging, Elevated Temperature, Charge/Discharge Cycles, Seismic Events	Reduced Capacity, Battery Failure	Corrosion, Fatigue
Terminal Posts	Lead Alloy (sometimes with copper inserts)	Humidity, Dust and Dirt, Electrolyte Leaks/Spills, Improper Handling	High Connection Resistance, Short Circuits, Reduced Output, Banery Failure	Corrosion, Fatigue, Fouling
Racks	Steel, Fiberglass	Electrolyte Leaks/Spills, Humidity, Seismic Events	Rack Failure, Loss of Battery	Corrosion, Fatigue
Terminal Post Seals	Rubber, Plastic	Plate Growth, Terminal Post Corrosion, Elevated Temperature	Loss of Electrolyte, Reduced Capacity, Battery Failure	Fatigue, Thermal Aging
Intercell Connectors and Associated Hardware	Lead-Plated Copper	Humidity, Dust and Din, Electrolyte Leaks/Spills, Improper Handling	High Connection Resistance, Reduced Output	Corrosion, Fatigue, Fouling

'Berg et al. 1994; p. 3-3 to 3-5 and 4-16 to 4-24.

Preventive maintenance programs assess a battery's condition through routine inspections and operability checks. The frequency of inspections is dictated by plant Technical Specifications and IEEE Std 450-1987 (IEEE 1987). Surveillance procedures use similar methods but yield more conclusive information about the state of battery degradation. For example, surveillance programs precisely evaluate battery performance by capacity tests.

"Good housekeeping" programs verify equipment operability by the routine logging of parameters, such as ambient temperature, float voltage, and charging current, during operator walkdowns. Online monitoring warns control room personnel of abnormal or fault conditions so that annunciator response procedures can be initiated. Corrective maintenance programs, like annunciator response procedures, can be applied in response to observed abnormalities, but can also mitigate future aging. For example, the damage caused by sulfation and hydration can be minimized by the corrective procedure of equalizing charge.

Table 8.2 Managing aging degradation for batteries

Component	Material	Aging Mechanism	Aging Management
Plates, Grid, Active Material	Lead/Lead-Calcium/ Lead-Antimony/Lead Dioxide	Material Chemical Changes, Corrosion, Fatigue, Gassing	Follow practices recommended in RG 1.129[a] and IEEE Std 450-1980[b] Apply commonly used programs and techniques, as appropriate:[c] • Preventive maintenance • Surveillance program • "Good housekeeping" practices • On-line monitoring and annunciator response procedures • Corrective maintenance procedures • Class 1E battery seismic qualification • Operational experience reviews and trending Apply less commonly used programs and techniques, as appropriate:[c] • Continuous environmental monitoring and environment mitigation • Sample cell analysis • Battery charger output waveform monitoring • Battery impedance testing • Battery conductance testing • Infrared thennographic inspection • Periodic battery replacement • Potential surveillance tests for detecting seismic vulnerability
Electrolyte	Sulfuric Acid	Material Chemical Changes, Gassing, Electrolyte Evaporation	
Separator	Rubber/Glass Mat or Microporous Polyethylene	Material Chemical Changes, Thermal Aging	
Container	Polycarbonate, Styrene Acrylenitrite, Butadiene Styrene	Material Chemical Changes, Fatigue, Thermal Aging	
Top Conductor1 Straps	Lead Alloy (sometimes with copper)	Corrosion, Fatigue	
Terminal Posts	Lead Alloy (sometimes with copper inserts)	Corrosion, Fatigue, Fouling	
Racks	Steel, Fiberglass	Corrosion, Fatigue	
Terminal Post Seals	Rubber, Plastic	Fatigue, Thermal Aging	
Intercell Connectors and Associated Hardware	Lead-Plated Copper	Corrosion, Fatigue, Fouling	

[a] Regulatory Guide 1.129, Rev. 1 (NRC 1978a)
[b] IEEE Std 450-1987 (IEEE 1987)
[c] Ber, Shao, et al 1994; pp 1-4 to 1-10

According to IEEE Std 535-1986 (IEEE 1986), battery seismic testing is required and must be performed at end-of-life conditions. This standard, endorsed by Regulatory Guide 1.158 (NRC 1989), explains that naturally aged batteries are preferred for testing, but also includes acceptable methods of accelerated aging.

Operational experience reviews compile and analyze recurring problems at many plants, including the host facility, in order to abate these problems through corrective measures. Performance trending, a part of this program, observes changes in battery parameters, like cell specific gravity and voltage, so that effective surveillance, maintenance, and/or replacement can be scheduled.

8.2 Battery Chargers and Inverters

Nuclear power plants use battery chargers and inverters to supply power to safety-related equipment, instrumentation, and controls. Battery chargers convert plant auxiliary AC power to regulated DC power for plant requirements, primarily the charging and floating of standby batteries, as well as for input into inverters. Inverters convert DC input power from a battery or battery charger to AC power for supplying critical ac loads, typically instrumentation and controls equipment necessary for safe plant operation and shutdown (Berg, Stroinski, et al. 1994). Battery chargers and inverters are considered together in this subsection because of their similarities in design, construction, parts, and materials. Both components experience similar environments and operational stressors and have the same subcomponents, such as diodes, relays, capacitors, integrated circuits, etc.

Three types of battery charger designs are used at nuclear facilities: the silicon controlled rectifier (SCR) solid state type, the controlled ferroresonant type, and the magnetic amplifier type. The SCR, or thyristor solid state charger, is most commonly used, making up nearly 75% of the population, and is the only charger type that is qualified to IEEE Std 323 (IEEE 1983) data and IEEE Std 650-1990 (IEEE 1990). Four basic inverter designs are currently in use: the ferroresonant transformer, the pulse-width modulated. the quasi-square wave, and the step wave. The first two types are used most often, with the last two types making up less than 20% of the inverter population.

8.2.1 Aging Concerns and Mechanisms

Battery chargers and inverters are exposed to generally the same stressors that act upon batteries (see Section 8.1.1). Table 8.3 shows the aging concerns and mechanisms which result from these stressors to degrade battery charger and inverter components.

Corrosion, fatigue, wear, thermal aging, and fouling are all aging mechanisms which damage battery charger and inverter components and have been previously described in Section 8.1.1. Aging mechanisms unique to charges and inverters are electronic drift, setpoint drift, and material set. Electronic drift degrades circuitry by time-dependent changes in electronic materials, resulting in the loss of calibration accuracy. Setpoint drift is the result of thermal aging, corrosion, wear, and fatigue working independently or synergistically over time (Berg, Stroinski, et al. 1994). Material set requires the hardening, gelling, or adherence of an organic component to adjacent materials, causing binding or misoperation of relays and circuit breakers.

8.2.2 Managing Aging Degradation

Table 8.4 summarizes effective programs for the management of aging caused by the mechanisms previously described. As with Table 8.2, commonly used programs are listed here along with less commonly used ones. IEEE Std 650-1990 (IEEE 1990) provides qualification requirements for battery chargers and inverters and helps identify any scheduled surveillance/ maintenance, periodic testing, and component replacement necessary to maintain qualification. Regulatory Guide 1.118 (NRC 1978b) focuses on general criteria for periodic testing.

Aging management programs for battery chargers and inverters are largely similar to the battery aging management programs described in Section 8.1.2. Programs that can be considered identical are 1) "good housekeeping" practices - operator rounds, logs, and checklists; 2) online monitoring and annunciator response procedures; and 3) operational experience reviews and trending. Unique to battery chargers and inverters, however, are the equipment qualification and infrared thermographic inspection programs. The equipment qualification program uses performance testing and parameter analysis to assess component reliability. The infrared thermographic inspection program uses infrared technology to detect "hot spots" for thermal aging and fatigue.

The rest of the techniques are similar in approach to the battery programs but different in detail. Preventive maintenance activities include the cleaning of dirt and debris, visual inspections for leaks and discolorations, tactile inspections, and calibrations. Surveillance programs verify acceptable component performance through periodic testing and observation beyond that required by Technical Specifications. Corrective maintenance, such as component replacement and cleaning, is performed in response to abnormalities or failures. Future aging can also be mitigated with certain procedures applied during corrective maintenance (Gunther et al. 1988).

Table 8.3 Aging concerns and mechanisms for battery chargers and inverters'

Components	Aging Mechanisms	Aging Concerns
Transformers	Thermal Aging, Thermal Stress Thermal Fatigue, Corrosion, Fatigue Fouling	Transformer Failure
Inductors	Thermal Aging, Thermal Fatigue, Corrosion, Fatigue, Fouling	Inductor Failure
Relays	Thermal Aging, Thermal Stress, Corrosion, Wear, Electronic Drift, Fatigue, Material Set, Fouling	Coil Failure Contact Failure Binding/Misoperation Setpoint Drift (Timing and Sensing Relays) Chatter
Capacitors	Thermal Aging, Thermal Stress. Fatigue, Fouling	Capacitor Failure
Silicon Controlled Rectifiers	Thermal Aging. Thermal Stress, Fatigue, Fouling	SCR Failure
Diodes	Thermal Aging, Fatigue, Fouling	Diode Failure
Surge Suppressor	Thermal Aging, Thermal Stress, Thermal Fatigue, Electronic Drift, Fatigue, Fouling	Surge Suppressor Malfunction Surge Suppressor Failure
Circuit Boards Resistors1 Transistors	Thermal Aging, Thermal Stress, Thermal Fatigue, Electronic Drift, Corrosion, Fatigue, Fouling	Circuit Board Output Changes Circuit Board Failure Signal Degradation
Circuit Breakers	Corrosion, Fouling, Thermal Aging, Wear, Fatigue, Material Set	Contact Degradation Restrike/Shorting Binding/Misoperation
Switches	Corrosion, Thermal Aging, Fouling, Wear, Fatigue	Contact Degradation/Failure Binding/Misoperation/Failure
Potentiometers	Corrosion, Wear, Electronic Drift, Fatigue, Fouling	Contact Degradation Potentiometer Failure
Wires and Cables	Thermal Aging, Corrosion, Fatigue, Fouling	Wire and Cable Failure
Cooling Fans	Corrosion, Wear	Degraded Performance/Failure
Cooling Fan Motors	Thermal Aging, Corrosion, Wear, Fouling, Fatigue	Degraded Performance/Failure
Cabinet	Corrosion	Loss of Structural Integrity

'Berg, Stroinski, et al. 1994; p. 4-13 to 4-16.

Table 8.4 Managing aging degradation for battery chargers and inverters

Components	Aging Mechanisms	Aging Management
Transformers	Thermal Aging, Thermal Stress, Thermal Fatigue, Corrosion, Fatigue, Fouling	Follow practices recommended in RG 1.118[1] and IEEE Std 650-1990[2] Apply commonly used programs and techniques, as appropriate:[3] • Preventive Maintenance Program • Technical Specification Surveillance Program • "Good Housekeeping" Practices - Operation Logs and Checklists • On-line Monitoring and Annunciator Response Procedures • Infrared Thermographic Inspection Program • Corrective Maintenance • Operational Experience Reviews and Trending Apply *less* commonly used programs and techniques, as appropriate:[4] • Environment Mitigation • Waveform Monitoring • Insulation Resistance Testing • Transformer Turns Ratio Testing • Sample Removal and Analysis • Equipment Replacement/Refurbishment • Environmental Monitoring • Transient Monitoring and Recording • Vibration Diagnosis
Inductors	Thermal Aging, Thermal Fatigue, Corrosion, Fatigue. Fouling	
Relays	Thermal Aging, Thermal Stress, Corrosion, Wear, Electronic Drift, Fatigue, Material Set, Fouling	
Capacitors	Thermal Aging, Thermal Stress, Fatigue, Fouling	
Silicon Controlled Rectifiers	Thermal Aging, Thermal Stress, Fatigue, Fouling	
Diodes	Thermal Aging, Fatigue, Fouling	
Surge Suppressor	Thermal Aging, Thermal Stress, Thermal Fatigue, Electronic, Drift, Fatigue, Fouling	
Circuit Boards Resistors1 Transistors	Thermal Aging, Thermal Stress, Thermal Fatigue, Electronic Drift, Corrosion, Fatigue, Fouling	
Circuit Breakers	Corrosion, Fouling, Thermal Aging, Wear, Fatigue, Material Set	
Switches	Corrosion, Thermal Aging, Fouling, Wear, Fatigue	
Potentiometers	Corrosion, Wear, Electronic Drift, Fatigue, Fouling	
Wires and Cables	Thermal Aging, Corrosion, Fatigue, Fouling	
Cooling Fans	Corrosion, Wear	
Cooling Fan Motors	Thermal Aging, Corrosion, Wear, Fouling, Fatigue	
Cabinet	Corrosion	

[1] Regulatory Guide 1.118, Rev. 2 (NRC 1978b).
[2] IEEE Std 650-1990 (IEEE 1990).
[3] Berg, Stroinski, et al. 1994; pp. 5-14 to 5-17.
[4] Berg, Stroinski, et al. 1994; pp. 5-27 to 5-32.

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9 Emergency Diesel Generator

The EDG system provides electrical power to the Class 1E bus in the event of a loss of offsite AC power. All EDG system components are located in the mild environment outside of containment and there is no basic difference in the PWR and the BWR applications. Each EDG unit is a complete, independent electric power generating system, consisting of a diesel engine, generator, electrical controls, auxiliary subsystems, and the engine support subsystems for 1) fuel oil storage and transfer, 2) cooling water, 3) engine starting, 4) engine lubrication, and 5) combustion air intake and exhaust. Each of these subsystems is described below.

- The EDG fuel oil storage and transfer subsystem includes all tanks, pumps, and piping up to the connection to the engine interface as defined by the engine manufacturer or unit specifications.
- The EDG cooling water subsystem includes the heat exchangers and all valves, pumps, and piping up to the engine interface.
- The EDG starting subsystem includes instrumentation and control subsystems; air compressors, dryers coolers, and receivers; devices to crank the diesel engine; filters; valves; and necessary piping up to the engine interface.
- The EDG lubrication subsystem includes the piping, pumps, filters, and associated auxiliary equipment and components required to provide essential heated and conditioned lubrication oil to the engine up to the engine interface.
- The EDG combustion air intake and exhaust subsystem supplies combustion air of reliable quality to the engine interface, and exhausts the products of combustion from the engine interface to the atmosphere. It consists of filters, silencers, support structures, screens and louvers, and ducts to and from the engine interface at the turbocharger(s).

A typical nuclear power plant has two or more independent EDG units (Kirkwood and Meyer 1989). The diesel engines are of the general size used for ship propulsion and stationary power applications, rated at 3000 to 10,000 horsepower each. Diesel engines are generally quite reliable and may operate for 20,000 or more hours between major overhauls in ship and stationary power service. Due to emergency loading tests and standby service, EDG engines generally age and wear at a faster rate and need overhauls more often.

9.1 Aging Concerns and Mechanisms

Most of the EDG components were designed for continuous use, not for standby and intermittent service. However, except for the periodic testing requirements imposed under Regulatory Guide 1.108 (U.S. Nuclear Regulatory Agency 1977) (now withdrawn), stressors affecting the aging of EDG units at nuclear power plants are quite similar to those imposed on EDG systems supplying hospitals, military facilities, and other critical installations. Figure 9.1 is a diagram of the major components and subsystems of an EDG system that includes data from an aging study showing the relative failure rates of the EDG components at NPPs (Hoopingarner et al. 1987). In this context, a "failure" is registered each time the EDG system cannot complete a fast-start and/or accept load within the allotted time,[1] or continue to run for the demand period.

[1]To successfully complete a fast-start, the cold EDG must automatically start within 10 to 13 seconds and attain the design-related load within 30 to 45 seconds (the allotted time varies within these limits for the various nuclear power plants).

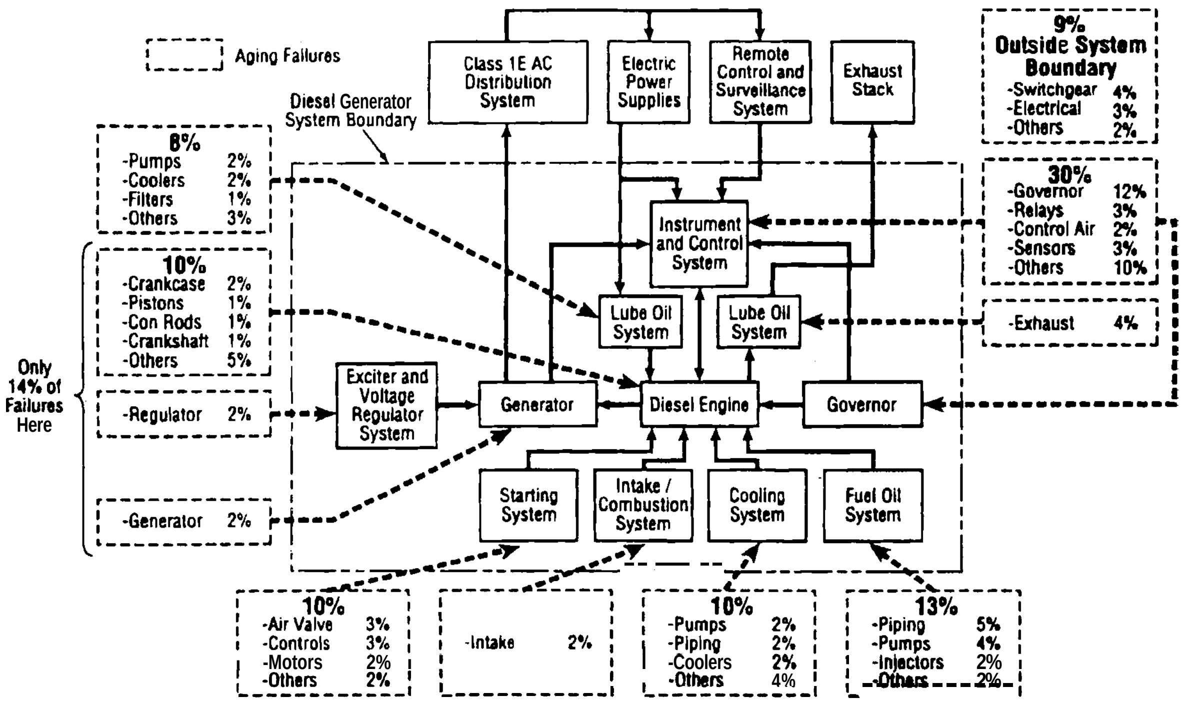

Figure 9.1 Diagram of the major components and subsystems of an EDG system

An important finding of these studies was that the EDG fast-starting and fast-loading testing program, undertaken in response to the old Regulatory Guide 1.108 (U.S. Nuclear Regulatory Agency 1977), was itself a major contributor to premature aging of the EDG units. The current applicable Regulatory Guide 1.9, Revision 3 has greatly reduced this source of aging stressors.

Other than the stresses induced by fast loading and short run times, Hoopingarner et al. (1987) found that the primary causes of EDG component failures were as follows (see Table 9.1):

(1) Vibration-induced loosening and vibration-induced deterioration of the governor and other components of the instrument and control subsystem. Vibration-induced fatigue failures and loosening of fittings and fasteners was also a major aging contributor for the fuel and cooling subsystems.

(2) Corrosion due to water in the starting and fuel subsystems.

(3) Corrosion of components of the cooling subsystem, sometimes compounded by deposition or microbiological attack.

(4) Fouling due to bacterial growth in water and fuel subsystems.

(5) Other causes include defects in design, manufacturing, and construction, and poor maintenance practices.

9.2 Managing Aging Degradation

Hoopingarner and Zaloudek (1989) have provided guidance on maintenance, surveillance, monitoring techniques, and practical engine management techniques for improving the reliability of EDG units. Additional detailed guidance has been provided by Lofgren et al. (1988) and Shah and MacDonald (1993). The recommended EDG aging management program incorporates more appropriately the roles of maintenance, operations, modified-testing, inspections, monitoring, and trending. Less emphasis on the statistics of engine reliability was found to be helpful in reducing aging effects.

Table 9.1 Aging degradation concerns and mechanisms for emergency diesel generators

System/Component	Aging Mechanism	Aging Concern	References[1]
I&C System Governor	Vibration, Heat, Oil Contamination and Dust Poor Maintenance and Maladjustment, Fast Starts	Wear, Oil Deterioration, Failure to Meet Performance Demands	pp. 884-885, 897-898, 919
I&C System Sensors and Relays	Vibration. Heat, Dust, Humidity, and Chemical Attack	Loss of Electrical Contact, Arcing, Vibration Loosening, Overheating, Drift and Maladjustment	pp. 886, 900, 919
I&C System Gages, Alarms and Shutdowns	Vibration, Humidity,	Vibration Loosening, Wear Drift, Corrosion, and Maladjustment	pp. 886, 900, 919
I&C System Control Air	Vibration, Moisture, Corrosion	Plugging, Fatigue of Lines, Maladjustment	pp. 886, 900, 919
Fuel Oil Piping on Engine, Filters	Vibration, Particulates and Biofouling in Oil	Fatigue of Fuel Oil Lines, Loosening, Filter Plugging	pp. 885, 898, 915
Fuel Oil Injection Pumps	Vibration and Adverse Internal Conditions	Binding, Scoring, and Poor Operation	pp. 882, 899, 915
Fuel Oil Injector Nozzles	Chemical Change, Biofouling, and Particles in Oil	Binding, Plugging, Poor Spray Patterns	pp. 882, 899. 915
Fuel Oil Fuel Oil Supply Components and Pumps	Chemical Change, Water in Oil, Bio-fouling, Metal-To-Metal Contact, and Loose Electrical Contacts	Wear, Loss of Pressure	pp. 915
Starting System Air Valve	Water and Particulates	Plugging, Binding, Failure to Close, Exposure to Exhaust Gases in Piping	pp. 881, 899, 915
Starting System Actuators and Controls	Moisture in Air, Vibration	Corrosion, Plugging, Binding, Loose Electrical Terminations	pp. 881, 899, 915
Starting System Starting Air Motors	Water, Particulates, and Vibration	Plugging, Binding, Failure to Operate, Vibration Loosening	pp. 881, 899, 916
Cooling System Pumps	Vibration, Poor Chemistry, Metal-to-Metal Contact	Wear, Vibration Loosening, Corrosion	pp. 884, 900, 916
Cooling System Piping	Vibration, Poor Water Chemistry, Exterior Attack by Fuel Oil	Leakage and Deterioration of Gaskets, Hoses and Flex Joints, Fatigue Failures	pp. 884, 900, 916
Cooling System Heat Exchangers and Radiators	Particulates, Poor Water Chemistry	Plugging, Corrosion, Internal Leakage in Heat Exchangers and External Leakage with Radiators	pp. 884, 900, 916
Lubrication Oil System Pumps	Vibration, Metal and Particulates in the Oil, High Pressure and Pressure Pulses	Vibration Loosening, Wear	pp. 883, 917
Lubrication Oil System Heat Exchangers	Corrosion, Particulates in Oil and Water	Plugging, Tube Thinning and Cracking	pp. 883-884, 917
Lubrication Oil System Filters	Particulates in Oil, Biofouling	Plugging, Loss of Oil Flow	pp. 883-884, 918
Lubrication Oil System Piping	Vibration, Pulsations	Fatigue, Fitting Failures, Oil Leaks	pp. 883-884, 917
Lubrication Oil System Oil	Particulates and Water in Oil, Bio-fouling, Standby Heaters Accelerate Oil Breakdown	Sludge and Foam, Chemical Deterioration	pp. 883-884, 917
Intake and Exhaust System Turbocharger	Vibration, Fast Loading Induced Surges and Poor Lube Oil Conditions, Deposit Induced Unbalance, Corrosion, Heat, Abrasion	Bearing Failure, Fatigue Fracture, IGSCC Fracture, Erosion	pp. 880, 898, 917

Table 9.1 (Continued)

System/Component	Aging Mechanism	Aging Concern	Reference[1]
Intake and Exhaust System Aftercooler	Vibration, Corrosion, Particulates	Leakage, Plugging	pp. 880, 898, 917
Intake and Exhaust System Filters and Duct Components	Vibration, Corrosion, Particulates	Vibration Induced Loosening, Filter Plugging, Corrosion Failures	pp. 880, 898, 917
Generator Voltage Regulator	Heat, Vibration	Loss of Function, Failed Contacts	pp. 885, 919
Generator Coils	Torsional Vibrations, Dust, Coil Stress, Insulation Breakdown	Coil Shifting and Fretting, Electrical Grounding, Cooling Passage Blockage	pp. 885, 919
Generator Exciter	Dust, Humidity, Vibration	Wear, Arcing, Loss of Function	pp. 885, 919
Switchgear Relays and Circuit Breakers These components are rather out of scope for EDG	Dust, Arcing, Humidity	Loss of Contact, Loss of Function	pp. 885, 919
Engine Structure Crankcase and Frame	Vibration, Thermal Stress. Fast Loading Adds to Stress	Distortion, Cracking. These are early failure problems	pp. 879, 900, 916
Engine Structure Cylinder Liners and Seals	Fast Loading, Thermal Expansion Caused Metal Contact with Pistons, Poor Lubrication at Startup, Chemical Attack on Seals	Scuffing and Wear	pp. 879, 900, 916
Engine Structure Main Bearings	Fast Loading, Poor Lubrication at Startup, Contaminants in Oil, Cavitation, Excess Heat	Scoring and Wear, Loss of Bearing Surface Material, Fatigue	pp. 879, 900, 917
Engine Structure Cylinder Heads	Thermal Stress, Hot Spots, Thermal Cycles	Cracking, Distortion, Water Leaks	pp. 897, 917
Engine Structure Bolting	Vibration, Overstress, Heat, Corrosion	Vibration Loosening, Fatigue Loosening Followed by Bending and Sheering Failures, Corrosion Induced Damage and IGSCC	pp. 897, 917
Drive Train Pistons and Rings	Fast Loading, Thermal Stress, Dynamic Stress,	Wear and Scuffing, Thermal Expansion Induced Metal-to-Metal Contact, Fatigue, Overstress	pp. 891-892, 896, 901, 918
Drive Train Connecting Rods	Dynamic Stress, Overstress	Fatigue. Often associated with bolting and oil hole areas and with early failures due to manufacturing defects.	pp. 879, 890, 896, 918
Drive Train Crankshaft	Dynamic Stress, Torsional Vibration, Poor Supply or Contaminated Lube Oil	Fatigue, Scoring. Fatigue is a very early failure cause in this component.	pp. 879, 890, 896, 918

[1] Unless other wise noted, the references are to pages of Shah and MacDonald (1993).

Changes in operation, maintenance, and regulation were projected to have important influences in the reduction of aging in the EDG system.

Regulation was found to have an important aging reduction role chiefly in Standard Technical Specifications and in Regulatory Guides (Hoopingarner 1991). Many technical specification and guide requirements are neutral in aging effects, however, eight beneficial improvements have been identified. Of these eight improvements, the three most important were reductions in testing load application rates, testing loads to less than the continuous rating, and the average number of tests. The NRC has acted to greatly reduce this source of aging.

The nuclear power industry has made some EDG design changes affecting engine standby conditions. These include keeping the lubrication oil moving to some of the bearings **and** components, heating the oil and coolant to keep the engine warm, and removing moisture by drying the starting-air during standby to reduce corrosion in the starting system. Another highly recommended modification is to isolate, where it is practical, the engine and generator instruments and controls from engine vibrations.

To manage aging degradation in EDG systems, the NPAR study results indicate that for each **significant** aging mechanism various management options are available. These are discussed here. Some aging mechanisms are very pervasive and affect all or almost all systems. Other aging mechanisms affect only one or two systems. Table 9.2 briefly shows these system and aging mechanism relationships. The following text amplifies the table **information.**

Table 9.2 Managing aging degradation in EDG systems

EDG System	Aging Mechanism	Management Options	References[1]
Essentially All EDG Systems	Vibration and Vibration Loosening	Replacement of fatigue failed components with identical components, not recommended. Apply a correct torque management program within maintenance program. Good monitoring and trending program.	pp. 902-905
Instrument & Control System	Dust, Humidity, Chemical Attack	Ensure good maintenance and design modifications for I&C system.	pp. 902-905, 922-923
Instrument & Control System	Vibration as a Special Case	Skid mounted instruments may be replaced due to vibration induced wear.	pp. 902-905, 922-923
Fuel System; Oil Supply Components and Filters	Water Biofouling, Particulates, and Chemical Changes in Oil	Maintenance program with recommended monitoring and trending.	pp. 902-905
Fuel System; Other Components	Wear, Plugging, and Binding	Maintenance program with recommended monitoring and trending.	pp. 902-905
Starting System; All Components	Water, Particulates and Corrosion	Ensuring that water is removed by design and maintenance actions.	pp. 897, 899
Cooling System; All Components	Poor Water Chemistry, Particulates	Recommended monitoring and trending program.	pp. 094-905
Cooling System; Hoses and Gaskets	Exterior Attack by Fuel Oil	Inspection for cracking and leaking.	pp. 910-911
Lubrication Oil System; All Components	Particulates, Water, and Biofouling	Recommended monitoring and trending program.	pp. 883-884
Intake and Exhaust System Turbocharger	Poor Lube Oil Conditions, Deposits, Corrosion, and Abrasion	Recommended monitoring and trending program.	pp. 898, 902-905
Intake and Exhaust System; Other Components	Filter Plugging and Corrosion	Inspections and monitoring of turbocharger performance.	pp. 898, 902-905, 910-911
Generator; All Components	Dust, Excess Heat, Winding Breakdowns and Other Faults	Recommended Monitoring and Trending Program and Inspections.	pp. 902-905, 910-911
Engine Structure; All Components	Early Failures Involving Cracking, Hot Spots, Heat, and Other Stressors	Most often resolved in the early site testing program, but monitoring and trending will often detect these.	pp. 902-905, 910-911
Engine Structure; All Components	Late Failures Involving Wear and Seal Aging	Recommended Monitoring and Trending Program Ind inspections.	pp. 902-905, 910-911
Drive Train; All Components	Thermal and Dynamic Stress and Poor Oil Conditions	Recommended Monitoring and Trending Program and Inspections.	pp. 902-905, 910-911

[1]Unless otherwise noted, the references are to pages of Shah and MacDonald (1993).

Aging Mechanism - Vibration Induced Fatigue and Loosening

- Affects essentially all EDG systems

  - Management options do not include replacement of components that fail by fatigue with identical components cannot be recommended, even though that is an industry standard practice. Options in order of successful mitigation are **1)** modify components and systems as needed to reduce fatigue **stressor** or material stress, 2) ensure that good torque management practices are in the diesel maintenance program, and **3)** establish a monitoring and trending program for the diesel units.

  - Handled as a special case, vibration induced wear and problems on skid-mounted instrumentation and sensors are probably best managed on a time-managed replacement basis with identical components.

Aging Mechanism - Water, Biofouling, Particulates, and Chemical Changes

- Affects fuel, starting, lubrication, and cooling systems

  - Management options in order of successful mitigation are 1) ensure that water is removed by design changes and routine maintenance actions, 2) ensure that chemical analysis and control programs are effective, and **3)** elements of a good monitoring and trending program will detect any adverse effects of most of these aging mechanisms.

Aging Mechanism - Dust, Humidity, and Chemical Attack

- Affects the instrument and control and generator systems

  - Management options in order of successful mitigation are **1)** good maintenance and design modification practices, **2)** careful inspections are important, and 3) the recommended monitoring and trending program will detect the effects of these aging mechanisms.

Aging Mechanism - Poor Lube-Oil Conditions, Deposits, Corrosion, and Filter Plugging

- Affects the intake and exhaust system

  - Management options in order of successful mitigation are **1)** the recommended monitoring and trending **program** will detect the effects of these aging mechanisms, and 2) inspections for the affect of these mechanisms adds to diesel reliability.

Aging Mechanism - All Those Affecting the Engine Structure and Drive Train

  - Management options in order of successful mitigation are **1)** the recommended monitoring and trending program will detect most of the effects of these aging mechanisms, and **2)** inspections for the presence of these mechanisms is important.

A new standard that incorporates EDG aging data and information has been released by IEEE. IEEE Std 1205-1993, "Guide for Assessing, Monitoring, and Mitigating Aging Effects on Class 1E Equipment Used in Nuclear Power Generating Stations," was approved by IEEE on March 18, **1993.** Appendix C.2 of this standard shows how it should be applied to the diesel generator. Also, standard **IEEE** Std **387-1984,** "IEEE Standard Criteria for Diesel-Generator Units Applied as Standby Power Supplies for Nuclear Power Generating Stations," has been changed extensively in response to changed regulatory guides **and** the NPAR aging information. IEEE Std **387** has been balloted, received IEEE approval, and a **1995** publication date is projected.

Different engine manufacturers and suppliers furnished diesel-generator sets to the industry. There were both common and different aging problems for these different EDG sets. To better manage aging **and** to improve availability, owners groups have been created by the users of these different engines. These groups have used the NPAR aging information along with operations data and manufacturer's recommendations to greatly increase the average engine reliability in the nuclear industry.

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10 Component Cooling Water Systems

The component cooling water systems (CCWSs) of concern are those that are required for safe shutdown during normal, operational transient, and accident conditions, and for mitigating the consequences of an accident or preventing the occurrence of an accident. These include closed-loop auxiliary cooling water systems for reactor system components, reactor shutdown equipment, ventilation equipment, and components of the ECCS.

In PWRs, the CCWS is a common system used to remove heat from various plant components and transfer it to an open loop cooling system such as service water. The CCWS is a non-radioactive, closed-loop cooling water system, which serves as a bamer between radioactive components and the open-loop cooling systems. The basic CCWS generally consists of several pumps, heat exchangers, a surge tank, and piping supplying the loads in a variety of header arrangements. Two typical designs for CCWSs used in operating PWR plants are shown in Figures 10.1 and 10.2. The CCWS for Plant A consists of two redundant safety-related loops and various loops for cooling non-safety-related components (Figure 10.1). The cooling loops are supplied by 3 CCWS pumps and three CCWS heat exchangers, each of which can supply either or both of the safety-related cooling loops. The CCWS is cooled by the service water system. The Plant B CCWS design includes three pumps, two heat exchangers, and one surge tank (Figure 10.2). The heat exchangers are cooled by service water from a nearby river on the tube side.

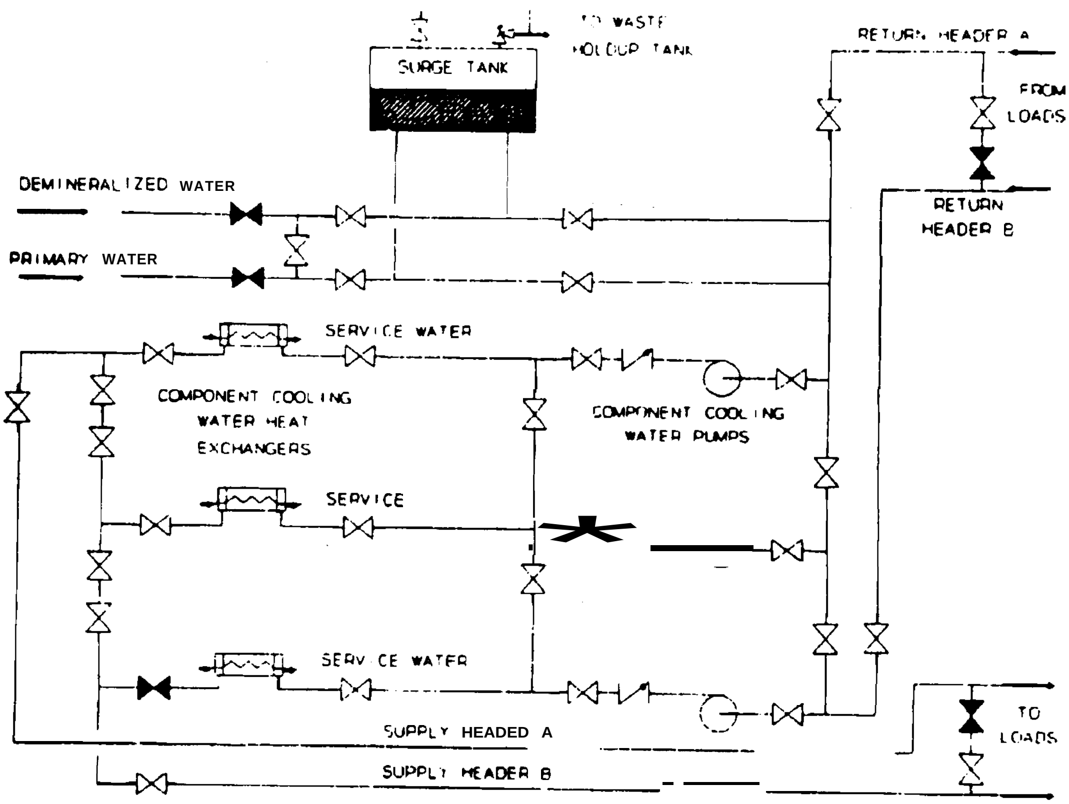

Figure 10.1 Plant A CCWS

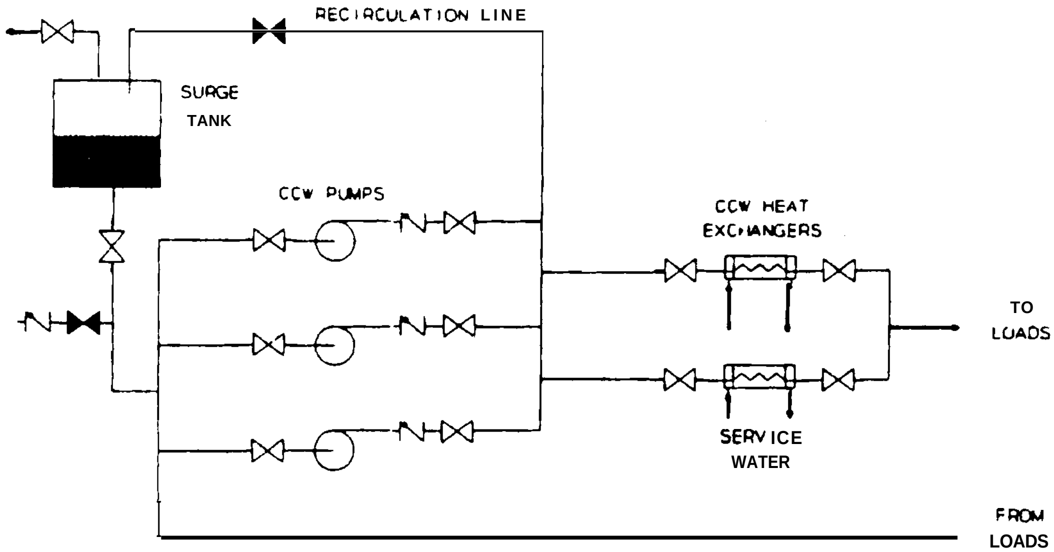

Figure 10.2 Plant B CCWS

The loads cooled or supplied by the CCWS vary from plant to plant. Typical safety-related loads by reactor vendor are

- Westinghouse - RHR heat exchangers (HX), RHR pump seals, safety injection (SI) pumps, containment spray pumps, containment coolers.

- Combustion Engineering - shutdown HXs, low-pressure SI pumps, high-pressure SI pumps, containment spray pumps, chillers, containment air coolers.

- Babcock & Wilcox - decay heat removal (DHR) HXs, DHR pumps, high-pressure injection (HPI) pumps, reactor building fan coolers.

10.1 Aging Concerns and Mechanisms

Higgins et al. (1988) have shown that environmental stressors (high temperature, high pressure, vibration, humidity, dust, etc.) contribute significantly to component failure in CCWSs. Table 10.1 summarizes the aging mechanisms and degradations resulting from these stressors for the major components.

10.2 Managing Aging Degradation

The components of a successful program to manage aging degradation are broadly twofold: 1) inservice inspection, surveillance, and monitoring methods (incorporating NDE and residual life assessments, where appropriate, as well as parameter trending and record-keeping) to assess the magnitude and rate of aging degradation; and 2) control measures to mitigate the adverse impacts of component aging on plant safety and capacity factors. Lofaro et al. (1992) determined that certain types of

Table 10.1 Aging concerns and mechanisms for component cooling water systems

Component	Material	Aging Concerns	Aging Mechanisms	References
Valves				Lofaro et al. 1992
Seal (packing)	PTFE, Graphite	Leakage	Wear	
Body	Carbon Steel, Stainless Steel	Wall Thinning	Corrosion	
Seat	Elastomer	Leakage	Wear	
Internal Parts	Stainless Steel	Distortion	Erosion/Corrosion	
Pumps				Higgins et al. 1988, Lofaro et al. 1992
Impeller	Bronze Alloy, Cast Iron, Stainless Steel	Distortion	Erosion/Corrosion	
Bearings	Cast Iron Class 30B	Leakage	Wear, Fatigue	
Primary Seals	Stainless Steels, Lead Bronze, Tungsten Carbide, Ceramics	Leakage	Corrosion, Erosion, Wear	
Secondary Seals	Rubber, Elastomer, PTFE	Leakage	Creep, Hardening	
Casing	Cast Iron, Carbon Steel	Leakage	Wear	
Heat Exchangers				Higgins et al. 1988, Lofaro et al. 1992
Tubes	Copper-Nickel, Brass/ Bronze/Admiralty, Stainless Steel, Carbon Steel	Fouling, Blockage, Leakage	Corrosion, Debris, Erosion, Wear	
Tubesheets	Copper-Nickel, Brass/ Bronze/Admiralty, Stainless Steel, Carbon Steel	Thinning	Corrosion, Erosion	
Channel Heads	Copper-Nickel, Brass/ Bronze/Admiralty, Stainless Steel, Carbon Steel	Thinning	Corrosion, Erosion	

degradation of CCWS components can be detected and mitigated. They recommended certain inspections and tests that included ASME Section XI (ASME 1992) requirements as well as other practices already used by some plants. These methods for managing aging degradation are summarized in Table 10.2.

Lofaro et al. (1992) suggested that the methods determined to be effective in detecting aging in CCWS components were also capable of mitigating that aging. That is, detection of aging degradation would identify the need for an appropriate maintenance action; this action would then be performed to mitigate the observed degradation.

Table 10.2 Managing aging degradation in component cooling water systems

Components	Materials	Aging Mechanisms	Management Options	References
Valves				Lofaro et al. 1992, Table 7. p. 7.4.
Seal (packing)	PFTE, Graphite	Wear	Check for excessive leakage/corrosion (daily to weekly)	
Body	Carbon Steel, Stainless Steel	Corrosion	Check for body wall thinning (5 to 10 years)	
Seat	Elastomer	Wear	Stroke valve (3-18 mo)	
Internal Parts	Stainless Dteel	Erosion/Corrosion	Lubricate moving parts (6 to 18 mo)	
Pumps				Lofaro et al. 1992, Table 7, p. 7.4.
Impeller	Bronze Alloy, Cast Iron. Stainless Steel	Erosion/Corrosion	Inspect for cracks, warping (12-60 mo), check for unusual noise (daily to weekly)	
Bearings	Cast lron Class 30B	Wear, Fatigue	Lubricate bearings/couplings (6-18 mo); monitor vibration (1-3 mo)	
Primary Deals	Stainless Dteels, Lead Bronze, Tungsten Carbide, Ceramics	Corrosion, Erosion, Wear	Check oil level (daily to weekly), analyze lube oil (1-6 mo)	
Secondary Seals	Rubber, Elastomer, PTFE	Creep, Hardening	Check for excessive leakage (daily to weekly)	
Casing	Cast Iron, Carbon Steel	Wear	Check for wall case thinning (5 to 10 years)	
Heat Exchangers				Lofaro et al. 1992, Table 7, p. 7.4.
Tubes	Copper-Nickel, Brass/Bronze/Admiralty, Stainless Steel, Carbon Steel	Corrosion, Debris, Erosion, Wear	Clean tubes: Check for excessive leakage/corrosion (daily or weekly)	
Tubesheets	Copper-Nickel, Brass/Bronze/Admiralty, Stainless Steel, Carbon Steel	Corrosion, Erosion	Check thinning	
Channel Heads	Copper-Nickel, Brass/Bronze/Admiralty, Stainless Steel, Carbon Steel	Erosion/Corrosion	Check thinning	

10.3 References

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11 Service Water System

The service water system (SWS) transfers heat from plant systems and components to the ultimate heat sink (UHS). The three safety-related heat sources served by the SWS in transferring heat loads from various sources in the plant to the UHS are core decay heat, decay heat removal components, and emergency power sources. In most designs, there is one SWS, but it is broken into essential and nonessential subsystems. Essential portions of the SWS, including the isolation valves separating the essential and nonessential portions, are classified Quality Group C and seismic Category 1. Because of the wide variation in each plant's UHS and the application of multiple system design approaches, the SWS is defined from a functional standpoint. The functional service water system boundary is defined in Figure 11.1.

Jarrell et al. (1989) assembled a database that contains a listing of the configurations, characteristics, and water sources for the SWSs in all commercial nuclear power plants in the United States. In the Phase II study, Jarrell et al. (1992) divided the systems into three general classifications by type of cycle: 1) open-cycle once-through systems, 2) open-cycle recirculating systems, and 3) closed systems. These types of systems are discussed briefly below.

The open-cycle once-through SWS, also referred to as a "straight through" system, is often used when a large volume of water is available for the UHS. A simplified diagram of a typical open SWS is shown in Figure 11.2.

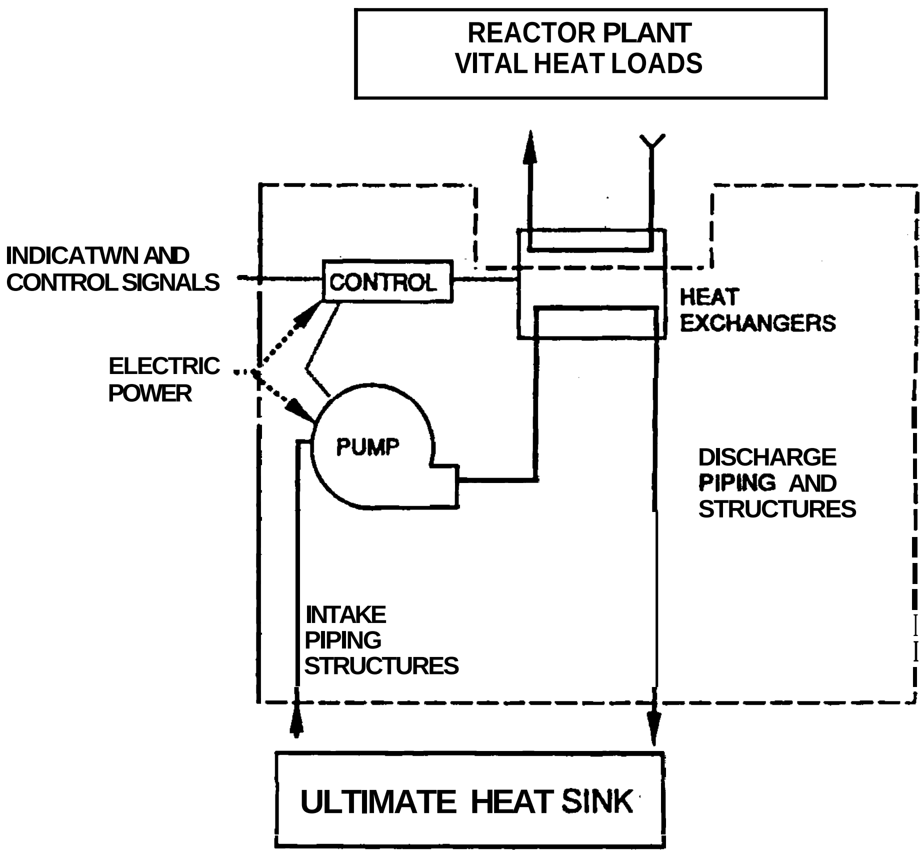

Figure 11.1 Service water system functional boundary

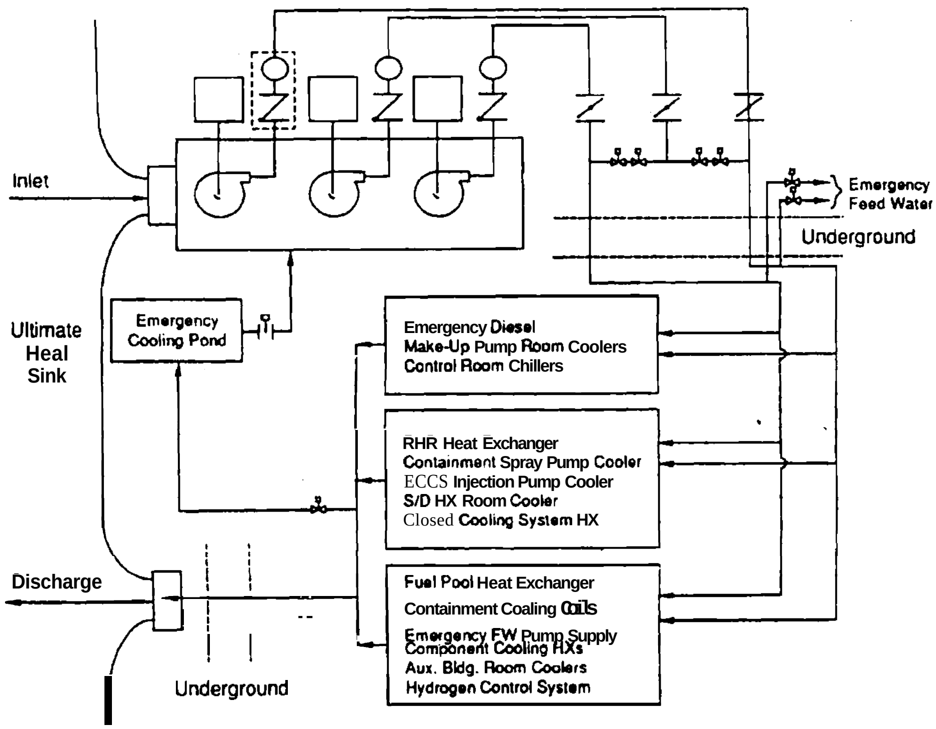

Figure 11.2 Open-cycle once-through service water system

Open-cycle recirculating systems use a self-contained UHS, such as a spray cooling pond or a dedicated cooling tower as shown in Figure 11.3.

The third general type of SWS is the closed-loop system; it resembles the open-cycle recirculating configuration, but adds an intermediate heat exchanger to prevent exposure of associated component load heat exchangers to a raw cooling water environment (see Figure 11.4).

More extensive and detailed descriptions of SWS configurations, characteristics, and water sources are presented by Jarrell et al. (1992) and Lam and Leeds (1988). Cramond et al. (1992) describe the SWS systems at eleven specific NPPs.

11.1 Aging Concerns and Mechanisms

Of the wetted systems in NPPs, the SWS seems to have the most aggressive combination of corrosive factors, even though the temperature range is relatively low (~0 to 50°C [32 to 120°F]). SWS components (pumps, valves, piping, heat exchangers, etc.) are subject to deposition, corrosion, and biofouling, the extent of which depends on the system type. Lam and Leeds (1988) reviewed operational experience with SWS, and performed a probabilistic risk assessment (PRA) for four NPPs. The results of the PRA show that degradation of the SWS can have a significant adverse impact on safe operation of a NPP. In a more comprehensive study, Cramond et al. (1992) performed PRAs for eleven additional NPPs. Their results verified the concern regarding reliability of the SWS and its importance to plant safety.

A root cause analysis of age related failures common to SWSs was performed by Jarrell et al. (1992). Based on this analysis, it was determined that the principal aging mechanisms leading to SWS degradation and failure are corrosion, biologic and

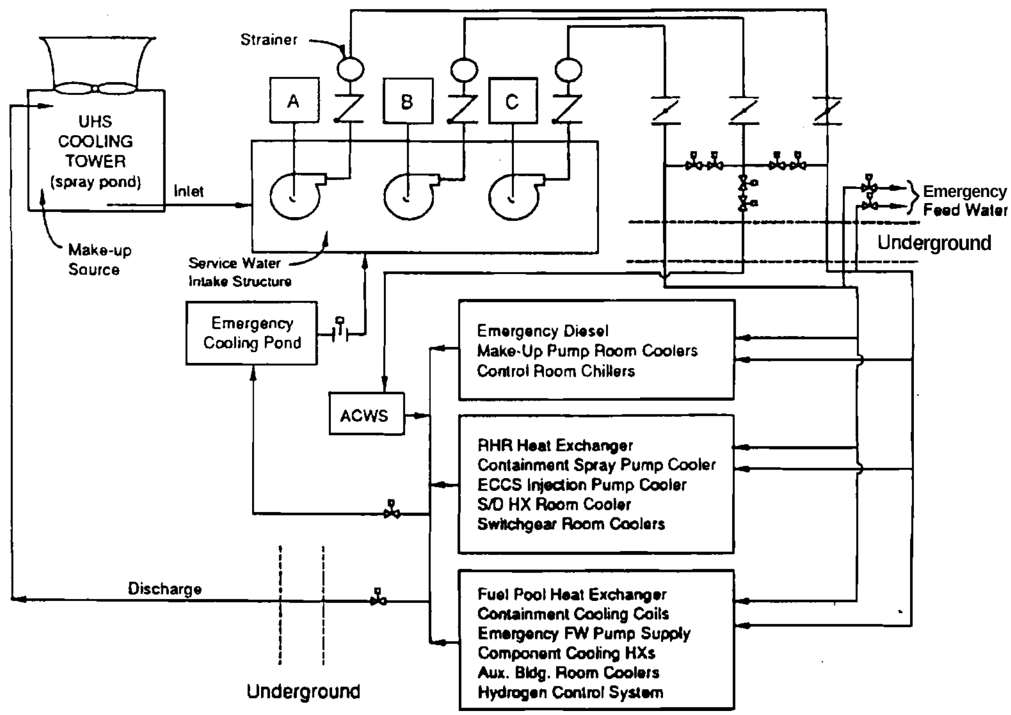

Figure 11.3 Open-cycle recirculating system

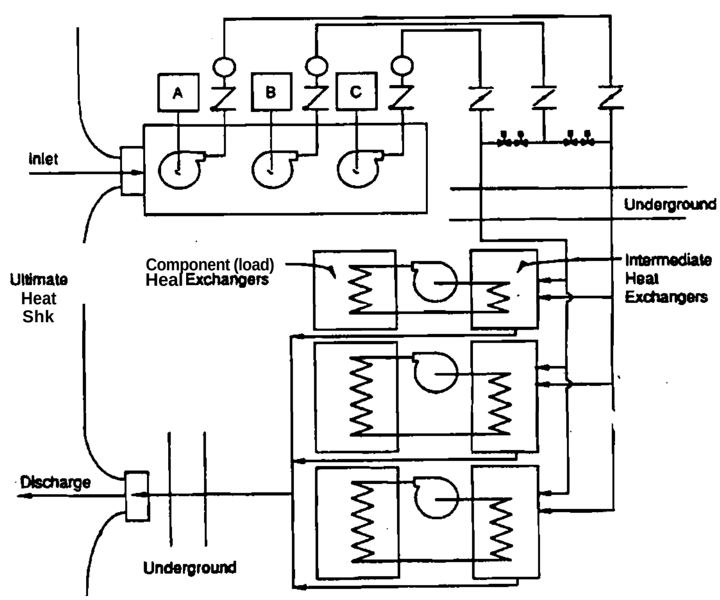

Figure 11.4 Closed-loop service water system

inorganic accumulation, and wear. Valve failures were primarily due to corrosion, whereas pumps were more likely to fail due to wear. Also, based on this examination, it appears that the recirculating SWS has the lowest failure rate of the three types of system cycles.

Table 11.1 provides the aging degradation concerns and mechanisms for the SWS.

Table 11.1 Aging concerns and mechanisms for service water systems

Component	Material	Aging Concerns	Aging Mechanisms	References
Pump Impeller	Brass	Distortion	Erosion, Corrosion	Orton and Allen 1995; Jarrell et al. 1992
Pump Casing	Cast Iron, Carbon Steel	Wall Thinning, Leakage	Corrosion, Erosion, Wear	
Pump Bearings	Cast Iron	Leakage	Wear, Abrasion	
Pump Seals and Gaskets	Rubber, Elastomer	Leakage	Creep, Hardening	
Valve Body	Carbon Steel, Stainless Steel	Wall Thinning	Corrosion, Erosion	
Valve Seat	Elastomer	Leakage	Wear	
Valve Internals	Stainless Steel	Distortion	Erosion, Corrosion	
Valve Seals, Gaskets	PTFE, Graphite	Leakage	Wear	
Heat Exchanger Tubes	Cu-Ni/Brass/Bronze/ Admiralty, Stainless Steel, Carbon Steel	Fouling, Blockage, Leakage	Corrosion, Debris, Erosion, Wear	
Heat Exchanger Tubesheets	Stainless Steel, Carbon Steel	Thinning	Corrosion, Erosion	

11.2 Managing Aging Degradation

Johnson and Jarrell (1991) have summarized the corrosion mechanisms and the water chemistry control measures and counter-measures that should be incorporated in programs to manage corrosion-related degradation of SWSs. Stewart and Smith (1992) provide generic guidance for risk-based inspection programs that include concerns for vulnerabilities that are not age related; however, their guidance reflects the risk significance of age-related degradation to the reliability of SWSs.

Table 11.2 indicates the management options to mitigate aging.

Table 11.2 Managing aging in service water systems

Component	Material	Aging Mechanisms	Management Options	References
Pump Impeller	Brass	Erosion, Corrosion	Visual Inspection, Acoustic Emission, Thermography	Orton and Allen 1995
Pump Casing	Cast Iron, Carbon Steel	Corrosion, Erosion, Wear	Internal Visual Analysis for Thinning	
Pump Bearings	Cast Iron	Wear, Abrasion	Acoustical Monitoring	
Pump Seals and Gaskets	Rubber, Elastomer	Creep, Hardening	Visual Inspection	
Valve Body	Carbon Steel, Stainless Steel	Corrosion, Erosion	Visual Inspection, MOV Diagnostic System (MOV-DS)	
Valve Seat	Elastomer	Wear	Visual Inspection, MOV-DS	
Valve Internals	Stainless Steel	Erosion, Corrosion	Visual Inspection, MOV-DS	
Valve Seals, Gaskets	PTFE, Graphite	Wear	Visual Inspection, MOV-DS	
Heat Exchanger Tubes	Cu-Ni/Brass/Bronze/ Admiralty, Stainless Steel, Carbon Steel	Corrosion, Debris, Erosion, Wear	UT, ET, Hydrostatic Testing	
Heat Exchanger Tubesheets	Stainless Steel, Carbon Steel	Corrosion, Erosion	Internal Visual Inspection, UT	

11.3 References

Cramond, W. R., D. B. Mitchell, J. L. Yakle, and S. P. Miller. 1992. *Loss of Essential Service Water in LWRs (GI-153).* NUREG/CR-5910, Prepared by Sandia National Laboratories for the U.S. Nuclear Regulatory Commission, Washington, D.C.

Jarrell, D. B., A. B. Johnson, Jr., P. W. Zimmerman, and M. L. Gore. 1989. *Nuclear Plant Service Water System Aging Degradation Assessment - Phase I.* NUREG/CR-5379, Vol. 1, Prepared by Pacific Northwest Laboratory for the U.S. Nuclear Regulatory Commission, Washington, D.C.

Jarrell, D. B., L. L. Larson, R. C. Stratton, S. J. Bohn, and M. L. Gore. 1992. *Nuclear Plant Service Water System Aging Degradation Assessment - Phase II.* NUREGICR-5379, Vol. 2, Prepared by Pacific Northwest Laboratory for the U.S. Nuclear Regulatory Commission, Washington, D.C.

Johnson, A. B., Jr., and D. B. Jarrell. 1991. "Corrosion and Corrosion Control in Nuclear Service Water Systems." In *International Conference on Nuclear Power Plant Operations - Ready for 2000,* pp. 38-45. American Nuclear Society, La Grange Park, Illinois.

Lam, P. S., and E. J. Leeds. 1988. *Operating Experience Feedback Report: Service Water System Failures* and *Degradations.* NUREG-1275, Vol. 3, U.S. Nuclear Regulatory Commission, Washington, D.C.

Orton, R. D., and R. P. Allen. 1995. *Recommendations for the Treatment of Aging in Standard Technical Specifications.* Draft NUREG, Prepared by Pacific Northwest Laboratory for the U.S. Nuclear Regulatory Commission, Washington, D.C.

Stewart, M. A., and C. L. Smith. 1992. *Generic Service Water System Risk-Based Inspection Guide.* NUREGICR-5865, Prepared by Idaho National Engineering Laboratory, EG&G Idaho, Inc. for the U.S. Nuclear Regulatory Commission, Washington, D.C.

12 Engineered Safety Systems

Nuclear plant compressed air systems consist of 1) the non-interruptible safety-related instrument air system (IAS), sometimes called the control air system; and 2) the non safety-related service air system (SAS), also called the station air system or the plant air system. The IAS provides the highest quality compressed air for pneumatic controls, air operated valve controllers and positioners, and pneumatic instrumentation in the nuclear power station. It is also the source of compressed air delivered to and stored in safety-related accumulators via safety-related check valves. The IAS is, therefore, vital for maintaining stable plant operation. Because of the fail-safe design and local safety-related air storage, the overall IAS is generally classified as non-safety. Its loss may result in a reactor trip or, on occasion, the actuation of ESF systems. The less quality-restrictive SAS provides compressed air for non safety-related systems, but may serve as a backup to the safety-related IAS. A risk-based review of IASs at nuclear power plants indicates that they contribute less to total risk than many other safety-related systems (DeMoss et al. 1990).

The IAS consists of air compressors, air dryers and filters, valves, instrumentation, and piping. The service air compressors, along with diesel start air compressors, are common to all plants and account for most of the compressor-related reportable events and maintenance calls. Aging of nuclear plant diesel start air compressors was evaluated by Hoopingarner et al. (1987). Aging of other components of the IAS was evaluated by Villaran et al. (1990) and Moyers (1990).

12.1 Aging Concerns and Mechanisms

Key compressed air system aging degradation concerns and mechanisms are presented in Table 12.1. Contaminants in the air have been identified as the dominant cause for most IAS component and air equipment deterioration. Moisture in the air leads to corrosion of internal parts of pneumatic devices; particulates can block the air flow through tubing, orifices, and ports of air-operated equipment; and hydrocarbons create gummy substances in the component internals leading to sluggish operation of moving parts. Other mechanisms affecting the IAS operation are bearing wear in the compressors, corrosion of cooling tubes and air equipment internals, and leakage of air through degraded seals and gaskets. Many of these problems can be attributed to the lack of proper maintenance and testing of IAS components. Wide ranges in the percentage of total failures exhibited by compressors, air dryers, and filters at different plants with different preventive maintenance practices for any given component indicate a direct effect of maintenance practices on the number of failures experienced.

Within the compressed air systems, compressors and air system valves dominate most component failures, followed by dryers and filters. A large fraction (60 to 89% depending on plant age; Villaran et al. 1990, pp. 4.2 and 4.4) of failures has been attributed to aging of these components. Wear from normal service caused compressors to fail to load/unload properly and to leak water or oil. Oil leaks in oil-less type compressors not only can generate hydrocarbon deposits and gummy-like residues in the valve internals causing sluggish or inoperable pneumatic valves, but they can also cause valve seals to become brittle and to stick to mating surfaces, thereby preventing proper valve motion. Blocking and clogging in pre- and after-filters have resulted in low air flow. Rust particles inside piping and connected equipment, due to moisture or water in the air supply, sometimes get dislodged during severe vibrations (e.g., flow-induced water hammers), and could adversely affect air-operated devices. Wear and corrosion accounted for more than half of the failures in which air system valves failed to open or close manual and power operated valves. The next most common failure mode was valve seat leakage (Villaran et al. 1990, pp. 4.16 and 4.20).

Design deficiencies that have affected aging and failures include inadequate capacity of accumulators, improper component sizing, valves failing to perform their intended functions under slow depressurizations of an IAS, faulty components, and incorrect selection of valve fail-safe positions.

Table 12.1 Aging concerns and mechanisms for compressed air systems

Component	Materials	Aging Concerns	Aging Mechanisms	References
Compressors and Intercooler	Cast iron main frame; forged steel or nodular iron crank shaft and connecting rod; aluminum or steel main bearings; aluminum or steel-backed copper-lead crank bearings; aluminum, tin-faced cast iron, or cast iron crosshead; hardened steel piston rod; aluminum or Ni-plated cast iron pistons; cast iron cylinders; stainless steel valve elements and seats; carbon or tetrafluoroethylene (TFE) rod packing, compression, and rider rings; admiralty brass heat exchanger tubes; neoprene coated steel heat exchanger shell	Leakage, failure to load or unload properly	Wear, fatigue, corrosion erosion, contaminants	Villaran, Fullwood, and Subudhi 1990, pp. 3.3 and 4.17-4.21; Moyers 1990, p. 13
Air Dryers	**Tower dryers -** alumina or silica gel desiccant; carbon steel vessel; stainless steel screens; carbon steel main air piping; steel valve hodies with stainless steel internals; copper valve control air piping **Refrigerated dryers -** carbon steel chiller and heat exchanger shells; admiralty brass or copper heat exchanger tubing	Delivery of moist air; loss of desiccant into air system	blocking, clogging. corrosion, deterioration, contamination	Villaran, Fullwood, and Subudhi 1990, pp. 3.1-3.4 and 4.19; Moyers 1990, p.17
Filters	[None specified]	Low air flow	Corrosion, saturation, blocking, clogging	Villaran, Fullwood, and Subudhi 1990, pp. 3.1-3.4 and 4.21
Valves	Stainless steel bodies; flexitallic or asbestos gaskets; EPDM, Viton, Buna "N," Nylon seats	Inability to open or close, seat leakage	Wear, corrosion, contamination, blockage	Villaran, Fullwood, and Suhudhi 1990, pp. 3.1-3.4, 4.16 and 4.20
Instrumentation	Polyethylene, copper	Incorrect signal, loss of function, loss of signal, erroneous indications, erroneous alarms, erroneous automatic actions	Calibration, setpoint drift, contamination, overheating	Villaran, Fullwood, and Subudhi 1990, pp. 4.17 and 4.21
Piping	Steel	Plugging, cracking leaking joints	Erosion, corrosion, blocking, clogging, vibration, overstress	Villaran, Fullwood, and Subudhi 1990, pp. 3.1-3.4, 4.17 and 4.20

12.1.1 Managing Aging Degradation

A summary of management options for reducing compressed air system aging degradation through inservice inspections, surveillance, and monitoring is provided in Table 12.2. In addition to starting problems, leakage of oil from oil reservoirs or bearings, water from the coolers, air from seals, and excessive vibration dominate the failures in the loadinglunloading valves of the compressor/receiver subsystem. Most of those are attributed to instrumentation/control problems (i.e., setpoint drift, calibration), wear of non-metallic components (e.g., seals, gaskets), and drainage-of-condensate problems. High pressure differential (AP) across the intake air filter indicates clogging with dust, water, and other atmospheric contaminants. Problems associated with loading/unloading valves, aftercooler or moisture separator corrosion/water leak problems, and drainage of condensate are not addressed in the suggested maintenance programs.

An effective approach to managing aging degradation must include a preventive maintenance program that periodically tests, monitors and inspects IAS components to detect degradation and provide criteria for repairs and replacement prior to failure. Plants with highest priority placed on compressor maintenance had the lowest frequency of compressor failures (Villaran et al. 1990, pp. 4.8 and 4.9). Programs that develop data from testing, operating parameters, and maintenance records for trending analyses should be implemented. Inspections and testing should include 1) verification of supply and delivered air quality (cleanliness, dew point, contamination, and hydrocarbon levels), and 2) monitoring coolant water, oil, and gas flow, temperatures, and pressures to detect degradation of performance in compressor, dryer, and heat exchanger systems.

The importance of training in preventive maintenance procedures is emphasized by the observation that human errors are the second most important cause of dual-tower desiccant-type air dryer failures resulting from normal service. Recommended testing and maintenance practices for compressed air systems are described in Section 6 of Villaran et al. (1990). Trending of all data acquired during testing, operating parameter data, and maintenance records is recommended for assessing component degradations.

12.2 References

DeMoss, G., E. Lofgren, B. Rothleder, M. Villaran, and C. Ruger. 1990. ***A Risk-Based Review of Instrument Air Systems at Nuclear Power Plants.*** NUREG/CR-5472, U.S. Nuclear Regulatory Commission, Washington, D.C.

Hoopingarner, K. R., J. W. Vause, D. A. Dingee, and J. F. Nesbitt. 1987. ***Aging of Nuclear Station Diesel Generators: Evaluation of Operating and Expert Experience. Phase I Study.*** NUREG/CR-4590, Vol. 1, U.S. Nuclear Regulatory Commission, Washington, D.C.

Moyers, J. C. 1990. ***Aging of Control and Service Air Compressors and Dryers Used in Nuclear Power Plants.*** NUREG/CR-5519, Vol. 1, U.S. Nuclear Regulatory Commission, Washington, D.C.

Villaran, M., R. Fullwood, and M. Subudhi. 1990. ***Aging Assessment of Instrument Air Systems in Nuclear Power Plants.*** NUREG/CR-5419, U.S. Nuclear Regulatory Commission, Washington, D.C.

Table 12.2 Managing aging degradation of compressed air systems

Component	Materials	Aging Mechanisms	Management Options	References
Compressor and Intercooler	Cast iron, forged steel, nodular iron, aluminum, steel, steel-backed copper-lead, tin-faced cast iron, babbitt-lined steel, babbitted cast iron, hardened steel, Ni-plated cast iron, TFE, admiralty brass or neoprene coated steel	Wear, fatigue, corrosion, erosion, contaminants	Conduct recommended preventive maintenance, lubrication, inspect for visible signs of degradation, corrosion, erosion, and loss of integrity; monitor vibration; document operating parameters of pressure drop, pressure, temperatures, flow rates, dew points, air quality, etc.; test performance of components and systems; perform trending analyses of operating data, test results and preventive maintenance records for early indications of degradation.	Villaran et al. 1990, pp. 3.4, 4.4, 4.5, and 6.1 to 6.8.
Air Dryer	Alumina, silica gel desiccant, carbon steel, stainless steel, carbon steel, copper, admiralty brass or copper	Blocking, clogging, corrosion, deterioration, contamination		
Filters	[None specified]	Corrosion, saturation, blocking, clogging		
Valves	Stainless steel, flexitallic, asbestos, EPDM, Viton, Buna "N" or Nylon	Wear, corrosion, contamination		
Instrumentation	Polyethylene or copper	Calibration, setpoint drift, contamination, overheating		
Piping	Steel	Erosion, corrosion, blocking, clogging, vibration, over stress, dirt and sludge accumulation		

13 High-Efficiency Particulate Air (HEPA) Filters and Adsorbers

Air treatment systems are among the Essential Auxiliary Supporting (EAS) Systems required for operation of ESF Systems. During normal plant operations, air treatment systems provide a safe and/or controlled environment for equipment and personnel, including removal of heat from rooms housing ESF equipment and ensuring habitability of the control room. Following an accident, air treatment systems operate to ensure the safe shutdown of the plant, allow equipment to be serviced, and provide the ultimate bamer to release of radioactivity to the public.

Air treatment systems are required to capture airborne particles and volatile species that may be suspended in, or exist as gas phase constituents of, recirculating aerosols, gaseous effluents, or accidental releases. Air treatment systems consist of some or all the following components: demisters, heaters, prefilters, high-efficiency particulate air (HEPA) filters, activated carbon gas adsorption units (adsorbers), postfilters, fans or blowers, ductwork, dampers, valves, and instrumentation and equipment to sample and monitor system performance. A typical configuration of an air treatment system is shown in Figure **13.1.**

Of these, the components most fundamental to providing plant and public safety are those designed to capture the particulate contaminants and the radioactive gaseous (volatile) contaminants, namely the HEPA filters and adsorbers, respectively. One or both of these components are installed in nuclear air treatment systems. The particulate matter could be radioactive chemical compounds or otherwise inert airborne material that has been contaminated by the adsorption of radioactive species, including cesium iodide (CsI). To capture these contaminants, the HEPA filters use a filter media made from a mixture of glass fibers that is formed into pleated "paper" to separate suspended particles from an essentially atmospheric pressure gas stream. A typical HEPA filter is shown in Figure **13.2** where the glass fiber filter paper is in the form of a continuous sheet pleated vertically over the separators. In addition to the filter paper medium, components of the HEPA filter include the frames, gaskets, face guards, and the corrugated separators that are used to separate adjacent sheets of the filter paper.

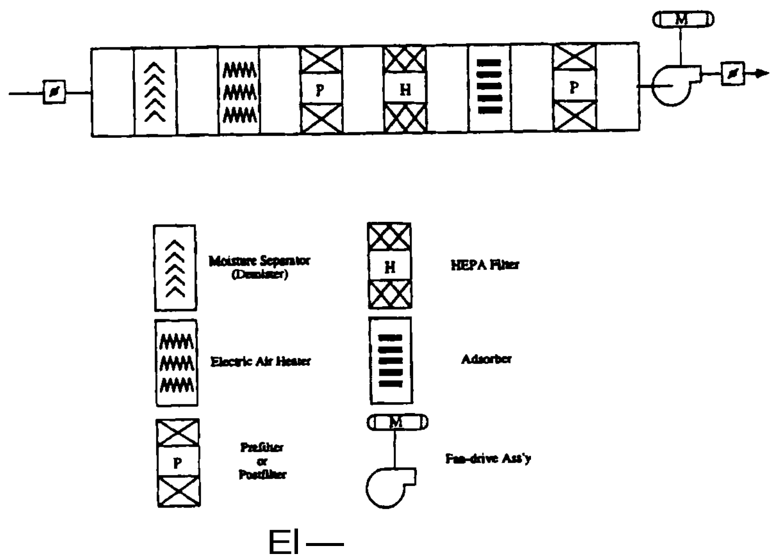

Figure 13.1 Typical air-treatment system

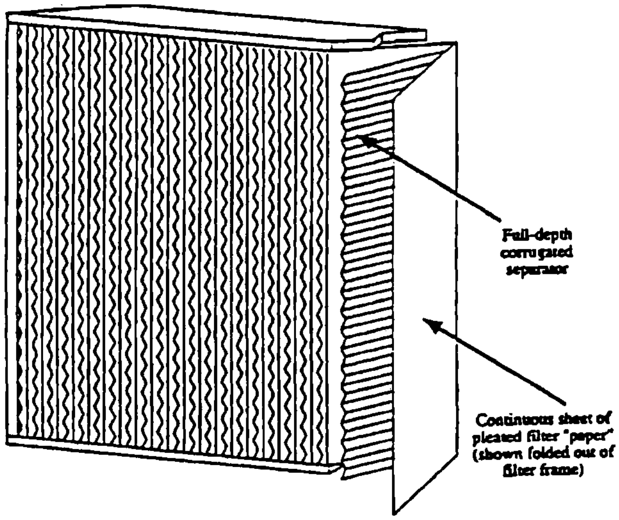

Figure 13.2 Typical HEPA filter construction

The radioactive volatiles of primary interest are the elemental and organic forms of iodine, the former being a major contributor to potential radiation doses to the plant personnel and public. To capture these contaminants, the adsorber shell directs the gasses through tightly packed beds of activated carbon granules, which are usually also impregnated with other chemicals to enhance the removal of organic species (e.g., methyl iodide). Type 304 or Type 304L series stainless steels are specified for the adsorber shell materials contacting the adsorbent.

13.1 Aging Concerns and Mechanisms

Winegardner (1993, 1995) reviewed data on the aging of HEPA filters and adsorbers including aging stressors, aging mechanisms, and their effects. He found that aging (e.g., the degradation of component performance over time) was not only caused by the direct retention of radionuclides, but also by heat, humidity, airborne contaminants and pollutants. A detailed discussion is given below. A summary of the aging concerns is provided in Table 13.1.

13.1.1 HEPA Filters

Increasing pressure drop (resistance to air flow) is an obvious result of HEPA filter use over time. Dust pickup of approximately 1 kg/1000m^3/h of design filtration capacity is sufficient to increase the filter"s flow resistance to twice the design resistance of a new filter (0.25 kPa) (First 1991). Dust loading, along with heat and radiation, also has the potential for reducing the effectiveness of the organic materials used to strengthen the filter medium and provide water repellence.

High moisture content in the airflow can increase the pressure drop, or AP, across the filter medium as well as reduce its tensile strength. This results principally from the presence of liquid water in the filter medium's fiber structure, where it is incorporated by sorption, condensation, or droplet filtration (Ricketts et al. 1987). The increase in AP in the filter medium, together with the decrease in tensile strength of the medium, leads to structural failure of the filter at unacceptably low values of AP, even at design flow rates.

Johnson et al. (1989) experimentally confirmed the effects of aging on HEPA filters. Aged sheet media samples, from dismantled filters having 13 to 14 years of service, were tested under conditions prescribed in Department of Defense Military specifications.

Table 13.1 Aging degradation concerns and mechanisms for HEPA filters and absorbers

Component	Material	Aging Concerns	Aging Mechanisms	References
HEPA Filter Media	Glass fibers	Fracture of fibers	Embrittlement	Winegardner 1993, 1995
HEPA Filter Frame	Wood products A1-alloy, cold rolled steel. chrome steel, stain-less steel	Leakage	Corrosion	
HEPA Filter Gaskets	Neoprene sponge rubber, cork	Leakage	Embrittlement	
HEPA Filter Corrugated Separators	Al-alloy, epoxy coated aluminum	Leakage	Corrosion	
Adsorber	Impregnated granular carbon	Loss of adsorbing capacity	Oxidation	
Adsorber Trays	Stainless steel	Pitting	Galvanic corrosion	

Forty-one percent of these aged samples failed the tensile strength test, 71% failed the pressure drop test and, when tested for water repellence, all failed when the top (dirty side) was tested while 57% failed when the bottom (clean side) was tested. Six filters in service 15 to 19 years and two filters in service 14 years were exposed in a wind tunnel to pressure pulses associated with the standard NRC Region I design basis tornado and to additive shock wave overpressures. Small incremental pressure increases were used on the two aged filters. The average breaking pressure was decreased 52% for the six aged filters and decreased 28% for the two incrementally stressed, aged filters. Recently Gilbert et al. (1995) have shown that filter media tensile strength decreases with age, but their data were not sufficient to establish a shelf life.

In addition to the filter medium itself, aging processes can adversely affect other filter components (Winegardner 1993, 1995). Corrosion of metal frames and corrugated separators can occur. Physicochemical reactions generated by heat and radiation can degrade the face gaskets as well as the adhesives and sealants that are used to splice the medium, fasten the gaskets to the filter face, and seal the filter pack to the frame.

13.1.2 Adsorbers

Continuous degradation of gas adsorbers over time (e.g., "weathering") is an inherent result of exposure to air containing moisture, contaminants, or pollutants (Winegardner 1993, 1995). This is because the adsorber material, impregnated granular carbon, has been "activated" to dramatically increase its surface area and provide countless reaction sites. Many airborne constituents can readily react with or be adsorbed by the activated carbon beds, thus reducing the number of active sites that would otherwise be available for the adsorption of radioiodine. During normal operation, airborne constituents may include moisture, volatile organic solvents, sulfur dioxide, nitrogen oxides, and carbon monoxide. Oxidation, as well as competitive loading, can impair bed performance, including decreasing the efficiency of the impregnant. Because the amount of airborne constituents is not constant with time nor from plant to plant, it is essentially impossible to provide criteria concerning the useful life of impregnated activated carbon.

The greatest degradation in adsorber performance is in the retention of methyl iodide as opposed to elemental iodine for which the loss in retention capacity is much slower (Burchsted et al. 1976). Moisture, when relative humidity is 70% and greater, is a significant factor in the degradation of impregnated charcoal retention of methyl iodide (CH_3I) (Dietz 1978). Moisture degrades KI-impregnate charcoals more than Triethylenediamine (TEDA)-impregnated charcoals due to oxidation of the carbon surface, which occurs less rapidly in amines (as TEDA) (Billinge and Broadbent 1989). Other contaminants can also degrade impregnated charcoals, with NO, and SO_2 having the largest effects, methyl-ethyl ketone (MEK) producing a mild effect, and NH, having a negligible effect (Wren and Moore 1991a,b). Moisture increases the adsorption rate and capacity of TEDA charcoal for NO„ but not for SO, (Wren and Moore 1991a).

Relatively rapid deterioration of the stainless steel components of the adsorber due to galvanic corrosion can result from contact with wet carbon. Guidance in this area is to be indicated in the revision to Regulatory Guide 1.52 (NRC 1978).

13.2 Managing Aging Degradation

Inspection, surveillance, and monitoring methods (ISMM) are used to establish the condition of HEPA filters and adsorbers once they have been put into operation. Requirements for ISMM are given in ASME N510-1989 (ASME 1989b), which is referenced in Regulatory Guide 1.52 (NRC 1978). When unacceptable aging degradation of performance is evident, replacement of the component is the primary method used for mitigating the degradation. A detailed discussion is given below. A summary is provided in Table 13.2.

13.2.1 HEPA Filters

Instrumentation requirements, including alarms, and surveillance test requirements for HEPA filters are presented in ASME N510-1989 (ASME 1989b). Differential pressure (due to pressure drop across the filter), uniformity of the mixing of the air stream approaching the HEPA filter bank, and filter leaks are continuously monitored or are the subject of periodic tests.

High differential pressure alarms are required at both local and remote manned control panel locations for HEPA filters in ESF air-cleaning systems. Pressure drop indication is required for the local station. For non-ESF systems, high ΔP alarms and ΔP indicators are recommended only for the local station. Filters are usually replaced prior to failure, primarily as a result of an indication of high AP.

Testing to verify uniformity of the mixing in the air stream approaching the HEPA filter bank is a prerequisite for conducting surveillance leak testing of the installed filter bank. This test is based upon the introduction of dioctylphthalate (DOP) aerosol into the air stream and taking concentration readings across a plane parallel to, and a short distance upstream of, the HEPA filter bank. The recommended frequency of the "air-aerosol mixing uniformity test" includes testing upon completion of initial construction and after each major modification or repair (acceptance tests).

Table 13.2 Managing aging degradation of HEPA filters and absorbers

Component	Material	Aging Mechanisms	Management Options	References
HEPA Filter Media	Glass Fibers	Embrittlement	Visual inspection, surveillance leak testing, air flow distribution tests	ASME 1989b; NRC 1978; Bellamy 1991
HEPA Filter Frame	Wood products Al-alloy, cold-rolled steel, chrome steel, stain-less steel	Corrosion	Visual inspection	Winegardner 1993, 1995
HEPA Filter Gaskets	Neoprene sponge rubber, cork	Embrittlement	Monitor HEPA filter pressure drop	Winegardner 1993, 1995
HEPA Filter Corrugated Separators	Al-alloy, epoxy coated aluminum	Corrosion	Visual inspection	Winegardner 1993, 1995
Adsorber	Impregnated granular carbon	Oxidation	Air flow distribution test	ASME 1989b; NRC 1978; Bellamy 1991
Adsorber Trays	Stainless steel	Pitting	Avoid wetting	NRC 1978; Bellamy 1991

Because gradual deterioration and leaks could develop under standby as well as service conditions, surveillance leak testing of installed HEPA filters is required. This test is also based on the introduction of DOP aerosol upstream of the filters. Concentrations are then measured upstream and downstream of the filters. Recommended frequency includes upon completion of initial construction and after each major modification or repair (acceptance tests), after each filter replacement, at least once each operating cycle, and after painting, fire, or chemical release if communication with the system occurred in such a manner that the filters could be adversely affected by the fumes, chemicals, or foreign objects (NRC 1978; Bellamy 1991). Visual inspection is required before each series of surveillance tests.

13.2.2 Adsorbers

Aerosol mixing tests, surveillance leak tests, and visual inspections, previously noted for installed HEPA filters, are also required for installed adsorbers (ASME 1989b). In addition, laboratory tests are required to determine the efficiency of used adsorbent material (ASME 1989a).

As with HEPA filters, verification of the uniformity of air-aerosol mixing in the approaching air stream is through DOP aerosol injection and subsequent concentration measurements upstream of the adsorber banks. The recommended frequency of this test includes upon completion of initial construction and after each major modification or repair (acceptance tests).

Surveillance leak testing of installed adsorbers uses a halide gas (a fluorocarbon). The halide is injected upstream of the adsorber bank, and concentration is measured upstream and downstream of the bank. The recommended frequency of leak testing includes 1) acceptance tests; 2) at least once each operating cycle; 3) after painting, fire, or chemical release in any ventilation zone communicating with the system; 4) following any evidence of water or other foreign material in an ESF atmosphere cleanup system; 5) following each partial or complete replacement of the carbon adsorber in an adsorber section or bank; and 6) following removal of an adsorber sample for laboratory testing if the integrity of the adsorber is affected (NRC 1978, 1979; Bellamy 1991). Visual inspection is required before each series of surveillance tests.

The leak test is supplemented by laboratory tests of used carbon samples to determine system efficiency and remaining capacity for methyl iodide. These samples are obtained from extra canisters of adsorbent installed in the air stream to determine the adsorbent's response to the service environment over its predicted life (ASME 1989a). Recommended frequency for the laboratory adsorbent tests includes 1) acceptance tests, 2) before each adsorber replacement, 3) at least once each operating cycle but not exceeding 720 hours of system operation (unless modified by laboratory test history), and 4) immediately following inadvertent exposure of the system to solvents, paints, or other organic fumes or vapors that could degrade the adsorber"s performance (ASME 1989b).

Nondestructive evaluation of performance degradation and assessment of residual life for installed HEPA filters and adsorbers are accessible from the required monitoring methods and surveillance tests. These include monitoring of AP to determine the age-dependent degradation of HEPA filters, surveillance leak testing of installed HEPA filters and adsorbers, and laboratory tests of used carbon adsorber samples to determine the remaining capacity for methyl iodide.

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14 Mechanical Structures and Components

This section is devoted to aging concerns and associated mitigation strategies for valves, pumps and support structures for PWR and BWR plants. The valves that have been considered in this assessment are 1) power-operated relief valves (PORVs), 2) MOVs, and 3) solenoid-operated valves (SOVs) and check valves (CVs). The pumps that have been considered are the ones for 1) the auxiliary feedwater system for the PWR and 2) the RCIC system for the BWR. Reactor pressure vessel supports and snubbers are the equipment and component support structures that have been considered in this section.

14.1 Valves

Valves are used to operate and control safety-related systems and components such as BWR control rod drives and the RCIC system. Valve degradation has occasionally resulted in marginal or nonfunctional performance. Valve disassembly-inspection testing, maintenance, and repair operations affect reactor outage schedules and are one of the primary sources of radiation exposure to maintenance staff. Considerable progress has been made to replace the disassembly-inspection tests and eliminate risk of improper reassembly with nonintrusive methods of valve diagnostics for PORVs, MOVs, SOVs, and CVs (Haynes 1992). The functions of the four types of valves are listed below:

- Power-operated relief valves require an external power supply for actuation, normally air or electricity, and are typically controlled by an electrical signal resulting from high system pressure or manual actuation from the control room. Although PORVs and associated block valves (BVs) were not designed as safety-related components, they are relied upon to mitigate certain design-basis accidents.

- Motor-operated valves are used in safety-related systems in nuclear power plant fluid systems. The most commonly used valve types are gate, globe, and butterfly valves. Significant maintenance efforts have resulted from failures with occasional compromise of the operational readiness of critical safety-related systems. The nonintrusive measurement of motor current signature analysis provides detailed information related to the condition of the motor, motor operator, and valve mechanical disorders across a wide range of levels from mean values and gross variations during a valve operation which characterizes transients and periodic occurrences. Numerous MOV monitoring systems are commercially available (Haynes and Fanner 1992, p. 3).

- Solenoid-operated valves are found throughout nuclear power plant safety-related systems, often a subcomponent of larger, more complex systems. These consist of electromechanical systems with numerous components subject to degradation from environmental exposure and repeated use. Conventional testing has included leakage, speed of operation, power consumption, and temperature. Newer methods of nonintrusive monitoring of performance parameters can detect and trend degradation with minimal cost and impact on plant operation (Kryter and Farmer 1992).

- Check valves are used to prevent flow in the wrong direction in nuclear plant safety systems. Many check valve failures have been attributed to severe degradation of internal parts (e.g., hinge pins, hinge arms, discs, and disc nut pins) resulting from instability (flutter) of these parts under normal plant operating conditions. Check valve instability may be a result of misapplication (e.g., using oversized valves) and may be exacerbated by low flow conditions and/or upstream flow disturbances. Combinations of acoustic/ultrasonic or acoustic/magnetic techniques can be used to diagnose check valve degradation. Check valve monitoring systems are commercially available (Haynes 1992, p. 24).

14.1.1 Aging Concerns and Mechanisms

Aging degradation in valves is a significant concern because failure of certain components can make systems important to safety unavailable. A summary of key aging degradation concerns and mechanisms is presented in Table **14.1.** The most common general failure modes are leakage and failure to operate as designed. Quarterly tests to ensure operability are required by Section XI of the ASME Boiler and Pressure Vessel Code (**ASME 1992)** or valves affecting safety systems; however, testing and maintenance often cause many of the same stressors as normal operation. These tests may contribute to premature failures, wear, and aging degradation. Other aging stressors also active during system standby conditions may act synergistically to degrade components. A single failure of any one of several valves could render a system inoperable. Aging degradation should be monitored and mitigated wherever possible to prevent system inoperability to an automatic-initiation signal. Codes and standards need to be upgraded to take advantage of nonintrusive diagnostics, now commercially available.

Table 14.1 Valve aging degradation concerns and mechanisms

Components	Materials	Aging Concerns	Aging Mechanisms	References
Body and Cap Assemblies	Stainless Steel	Cracking Leading to Leakage	Fatigue, Wear, Corrosion, and Erosion of Seats	**Conley 1990,** p. **42**
Stud Bolts	Stainless Steel	Stress Relaxation, Fracture	Galling, Stress Corrosion Cracking	**Conley 1990,** p. **16**
Gaskets	Flexitallic or Asbestos	Leakage	Corrosion, Erosion, Embrittlement	**Conley 1990,** p. **42**
Seating Materials	EPDM, Viton, Buna "N," Nylon	Leakage	Corrosion, Erosion, Embrittlement	**Conley 1990,** p. **42**

The failure mechanisms of valves is dependent on the environment and operating requirements for each valve type. Some common failure mechanisms are:

- Power operated relief valve failures have consisted of valve leakage, regulator leakage, limit switch malfunction or adjustment problems, air regulator leak, and failure to reset. Most leaks have been due to steam/water cutting the seat/plug interface. Degradation of the air or electrical actuation controls may prevent operation of the PORV (Murphy and Cletcher **1987).**

- The most common MOV failure modes are internal and external leakage due to erosion and corrosion. These conditions may be caused and accelerated by lodging of solid particles between the obturator and the valve seat or by corrosion products at the valve stem-packing interface. Degradation in MOVs includes wear, corrosion, and aging degradation, some of which could be reduced if vendor-specified lubricants were systematically used. Degradation of MOV power cables has resulted from cables unable to conduct the locked rotor current, which is much higher than the nameplate full load current. Electrically backseating valves using oversized motors has overstressed valve stems and valve seats. Damage to the stem-packing interface can also be caused by loose bolts or nuts holding the MOV assembly. Stress corrosion cracking has occurred in alloys such as Type **410** stainless steel with high residual stresses. Valve components have been degraded by wear, fatigue, embrittlement, degraded insulation, testing damage, poor adjustment, and erosion (Greenstreet et al. **1985).**

- Common SOV seating materials include ethylene propylene diene monomer (EPDM), Viton, Buna "N," and nylon. Temperatures up to **80** to 100°C (176 to 212°F) caused by a continuously energized coil and heating from process lines or a high-temperature environment cause rapid deterioration of these elastomeric parts. Seats and O-rings may harden, crack, or assume a compressive set that can result in leakage past the seat of a closed valve or through the spaces between valve body parts. Interaction between the varnish coating and the Class H insulation at high temperatures has also led to dielectric breakdown and turn-to-turn shorts in coils. Inductive surge following current interruption in DC energized coils can lead to arcing through the coil insulation during cyclic operation (Bacanskas et al. **1987,** pp. 24-26).

Erosion and wear from fluid flow, contaminants, low dose-rate radiation, and high temperature can result in cracking or pitting of the seat. ,Wear of surface interfaces from vibration, turbulence and water hammer can cause the core assembly to move off center and bind or stick.

Other materials of construction for SOVs such as stainless steel subassemblies and core spring, electrical housing and disc-holder spring, and a brass or stainless steel valve body appear to have few problems.

- The CV body and cap are primarily stainless steel. Type 304 or Type 316 stainless steel is generally used for the cap stud bolts. These require lubrication to prevent galling. Check valve seats are generally machined into the forging on less than 3-inch [7.6 cm] valves and in larger valves are generally replaceable hardened Stellite or Hastelloy. The valve body alloy is normally used for CV obturators to accommodate thermal expansion. Stellite or another hard alloy may be used for Ball CV obturators to resist wear and scratching. The hanger pin, hanger, and fastener are generally stainless steel. Hanger pin bearings are usually made of a hardened alloy such as Stellite. Check valves with pressure-seal construction use a steel sealing ring and bolt configuration, whereas machined surfaces require asbestos-type gaskets. Flexitallic-type gaskets of stainless steel and asbestos are deformed by tightening and should be used only once. A few CV designs use graphite-asbestos packing for the hanger pin (Greenstreet et al. 1985, p. 9).

14.1.2 Managing Aging Degradation

Valves are among the most commonly failed components. Some options for management of aging are presented in Table 14.2. The mechanisms causing these failures include wear aggravated by improper cable size, motor size, valve size, lubrication, water hammer, setpoint drift, and out-of-calibration instrumentation.

Table 14.2 Managing valve aging degradation

Components	Materials	Aging Mechanisms	Management Options	References
Body and Cap Assemblies	Stainless Steel	Fatigue, Wear, Corrosion, and Erosion of Seats	Minimize water hammer, contaminants, particulates, vibration, and temperature gradients; avoid electrically backseating; use proper motor size; avoid excessive cyclic operation.	Conley 1990, p. 90
Stud Bolts	Stainless Steel	Galling, Stress Corrosion cracking	Avoid using bolts with high residual stresses; use alloys with low potential for stress corrosion cracking; apply proper torque; use recommended lubricants.	Conley 1990, p. 16
Gaskets	Flexitallic or Asbestos	Corrosion, Erosion, Embrittlement	Avoid high temperature and high radiation fields, use specified lubricant; do not reuse deformable gaskets.	Conley 1990, p. 42
Seating Materials	EPDM, Viton, Buna "N", Nylon	Corrosion, Erosion, Embrittlement	Minimize contaminants and particulates in fluid; use proper valve design and size; use specified lubricants; avoid electrically backseating.	Conley 1990, p. 90

Most failures were detected during testing and operations. The high percentage of failures detected during surveillance testing and operation is an indication that only a very small number of failures are identified during preventive maintenance before they could cause a system malfunction. Suggested practices to reduce or mitigate valve failures are listed below.

- The greatest improvement in reliability of PORVs would result from using newer, more reliable PORV designs and improving testing, diagnostics, and maintenance applied to PORVs and BVs, particularly the BV motor operator (Murphy and Cletcher 1987). Because of the relief function of PORVs, the greatest safety benefit can be achieved by using designs that are resistant to sticking open.

- Improvement in several practices would improve the service of MOVs. Wear, corrosion, and aging degradation could be reduced by adhering to vendor specified lubricants. The service life of MOV power cables could be extended by using cables capable of conducting the locked rotor current, which is much higher than the nameplate full load current. Over-stressing of valve stem and valve seats could be reduced by not electrically backseating the valves. Stress corrosion cracking could be reduced by replacing materials that are susceptible to stress corrosion cracking, such as Type 410 stainless steel bolting. Advanced non-intrusive diagnostics and trending as a measurement of aging should be used to replace disassembly and intrusive testing.

- Solenoid-operated valve stressors that should be controlled or eliminated are high dose-rate radiation, high transient line voltages, elevated DC voltage during station battery float charging, frequent cycling in valve operation, corrosion products and other contaminants in the process fluid, and pressure transients (Bacanskas et al. 1987, p.24).

- Check valve stressors that cause aging degradation are vibration, flow-induced forces, flow transients, hydraulic forces, water hammer, foreign objects lodged between the seat and obturator, and thermal cycling. Thermal- and radiation-induced degradation of valve gaskets is a significant aging-related effect. Check valve materials tend to be resistant to corrosion, except for some effects from borated water (Greenstreet et al. 1985, p. 14).

Improvements in the operation of the HPCI system could reduce the stressors on valves (Conley 1990). The incidence of water hammer events could be reduced by design and procedure modifications for opening isolation valves and by implementing drain pot, keep-full, void detection, and venting system improvements. The wear and aging degradation caused by fast starts could be reduced if the HPCI response time were relaxed to 60 seconds. The HPCI system could be running and available for immediate return to full service without a challenging startup if the systems were switched to recirculation to the condensate storage tank after recovery of the water level has been verified.

Considerable progress has been made in the development and application of advanced and nonintrusive diagnostic methods to trend degradation in mechanical, electrical, instrumentation, power cables, instrumentation cables, connectors, and control components. These need to be applied for nondestructive evaluation and residual life assessment to replace disassembly-inspection tests and eliminate risks from improper reassembly. Nonintrusive methods of valve diagnostics are commercially available for PORVs, MOVs, SOVs, and CVs (Haynes 1992).

14.2 Pumps

Pumps are among the most commonly failed nuclear reactor plant components. This section describes concerns and mechanisms of pump aging and indicates how industry is managing aging pumps. Coolant pumps provide the flow of water that transfers heat generated by the nuclear fission out of the reactor core. The primary coolant pumps provide for the removal of heat during normal steady-state operation. In a PWR, auxiliary feedwater pumps deliver water from a condensate storage tank or from the emergency service water system to the steam generators. Auxiliary feedwater pumps are multistage (5 to 9 stages) high-head centrifugal pumps driven by motors or turbines. The pumps are automatically started in response to several emergency conditions, such as low steam generator level, a safety injection signal, or emergency bus undervoltage. Auxiliary feedwater pumps are also used to support normal shutdown and startup sequences. Auxiliary feedwater pumps usually operate at low-flow conditions.

The BWR RCIC system is an ESF system that incorporates a pump to supply high-pressure cooling water to the reactor vessel and provides a limited decay heat removal capability whenever the main feedwater system is isolated from the reactor vessel. The HPCI pump assembly includes a main pump driven directly by the HPCI steam turbine and a booster pump driven from the main pump shaft. The HPCS pump is an electricallydriven centrifugal pump. Abnormal events which could cause such a situation to arise include an inadvertent isolation of all main steam lines, loss of condenser vacuum, pressure regulator failures, loss of feedwater, and the loss of offsite poser. For each of these events, the high pressure part of the ECCS provides a backup function to the RCIC system.

14.2.1 Aging Concerns and Mechanisms

The aging mechanisms that have affected components of reactor coolant and recirculation pumps are 1) casings (thermal embrittlement, thermal and mechanical fatigue, stress-corrosion cracking, high residual stress as a result of no post-weld heat treatment, erosion and erosion/corrosion, and crevice corrosion), 2) closure studs (corrosion and stress corrosion cracking), and 3) shafts (mechanical and thermal fatigue and corrosion). These aging concerns and mechanisms are summarized in Table 14.3. Cavitation/erosion has not been a concern for reactor coolant and recirculation pumps. However, the low-flow operating and testing condition for auxiliary feedwater pumps accelerates the wear from hydraulically unstable conditions. The wear can result in impeller or diffuser breakage, thrust bearing and/or balance device failure due to excessive loading, cavitation damage on suction stage impellers, increased seal leakage, seal injection piping failure, shaft or coupling breakage, and rotating element seizure (Haynes 1992).

Table 14.3 **Pump aging degradation concerns and mechanisms**

Component	Materials	Aging Concerns	Aging Mechanisms	References
Casing	Carbon Steel, Low Alloy Steel	Cracking Leading to Leakage	Thermal embrittlement, fatigue, wear, erosion, stress-corrosion cracking	Conley 1990, pp. 16, 17, 27, 44, 46
Bearing Housing	Cast Iron	Leakage	Fatigue	
Impeller	Stainless Steel	Leakage	Fatigue	
Shaft	Stainless Steel	Cracking	Fatigue, corrosion	
Nuts and Bolts	Low Alloy Steel	Stress Relaxation, Cracking	Galling, wear, fatigue, stress-corrosion cracking	
Cables	Polyethylene, Copper	Calibration Drift	Corrosion, embrittlement	

Thermal embrittlement results from prolonged exposure of cast stainless steel pump casings with duplex austenitic/ferritic microstructures to typical operating temperatures on the order of 288°C (550°F). Operating temperature transients and vibrations subject pump casings to thermal and mechanical fatigue. High residual stresses in pump welds made using the electroslag techniques enhance fatigue damage at the weldments.

Closure studs are subject to corrosion and stress-corrosion cracking. Shafts are subject to mechanical and thermal fatigue and corrosion. Cavitation/erosion is a concern for many pumps, although it has not been identified as a concern for reactor coolant or recirculation pumps.

Two concentric Type 304 stainless steel-graphite-asbestos gaskets seal between the PWR coolant pump cover and casing. A leakoff line permits detection of reactor coolant leakage through the inner gasket and must be maintained free from plugging. Reactor coolant may corrode the low alloy steel (SA193 Grade B7 or SA540 Grade B23) closure studs. A single gasket is used in BWR coolant pumps.

Alternating mechanical bending stresses and rapidly varying thermal stresses[1] cause high-cycle mechanical and thermal fatigue in pump shafts. The bending stresses are caused by asymmetric distributions of pressure. These stresses, when superimposed upon stress risers and high residual stresses at welds on the shaft surface can initiate circumferential cracks and propagate them in a plane perpendicular to the shaft axis. These cracks usually occur in grooves on the shaft surface and propagate in a transgranular manner.

Aging degradation of pumps is a significant concern in RCIC systems, because a single failure of the pump assembly or the turbine would make the system unavailable. Reactor core isolation cooling standby safety systems are frequently tested to ensure operability; however, testing and maintenance often cause many of the same stressors as normal operation. These tests may contribute to premature failures, wear, and aging degradation in pumps and other components. Other aging stressors

[1]Thermal barriers or heat exchangers limit reactor coolant heat reaching the mechanical seal cavity, but induce thermal stress cycling in the pump shaft.

also active during system standby conditions may act synergistically to degrade components. Stressors for the HPCI pump assembly include pressure; lubrication problems; testing and maintenance leading to fatigue, wear, and leakage; vibration; and cavitation.

14.2.2 Managing Aging Degradation

A summary of viable options for managing aging degradation is provided in Table 14.4. All pumps that perform safety related functions are required to meet the inservice testing (IST) requirements of the applicable ASME Code. Non-intrusive trending of pump pressure and flow (Stockton 1992), vibration (Guy 1992), and bearing temperature, lubricant pressure, and pump power (Hoyle 1992) is preferred, where possible, to disassembly-inspection tests; it supports ALARA and eliminates risk from improper reassembly. If required, disassemble pumps for inspection and maintenance at specified intervals. Examine welds by surface and volumetric (radiography or advanced ultrasonic methods, if appropriate) examinations. The inservice inspection requirements of Section XI of the ASME Code (ASME 1992), which are currently limited to volumetric examinations, should be supplemented to include visual inspections. Pump shaft inspections during shutdown should include surface and volumetric examinations. Radiography is generally used for volumetric examination because ultrasonic waves are severely attenuated by the coarse grains in the steel. Radiographic triangulation is required to evaluate the location and size of a flaw. Advanced ultrasonic inspection, when developed, could provide improved inspection capability (Egan et al. 1987; Jeong and Ammirato 1988).

Improvements in the mitigation, detection and trending of pump aging problems can be achieved by incorporating the following practices:

- Conduct volumetric (radiography or advanced ultrasonic methods, if appropriate) and visual examinations of all bolts, studs, nuts, and bushings during each inspection interval. Remove insulation and paint if required for visual access. Examine pump cover and casing flange surfaces.

- Monitor radial pump motor frame vibrations for pump shaft damage, and monitor pump shaft proximity for circumferential cracks from mechanical and thermal fatigue. Conduct surface and volumetric (radiography or advanced ultrasonic methods, if appropriate) examinations of the pump shaft.

- Tighter specification of certain materials of construction and fabrication methods could potentially provide marked improvements in auxiliary feedwater pumps' durability and reliability. The application of state-of-the-art monitoring techniques should be studied in regard to its value in assessing wear and aging factors.

Table 14.4 Managing pump aging degradation through inservice inspections, surveillance, and monitoring

Components	Materials	Aging Mechanisms	Management Options	References
Casing	Carbon Steel, Low Alloy Steel	Thermal embrittlement, fatigue, stress, wear, erosion, corrosion, stress corrosion cracking	Trend motor frame and shaft proximity vibrations, flow, differential pressure; examine visually, use specified lubricant	Conley 1990, p. 27
Bearing Housing	Cast Iron	Fatigue		
Impeller	Stainless Steel	Fatigue		
Shaft	Stainless Steel	Fatigue	Surface and volumetric inspection	
Nuts and Bolts	Low Alloy Steel	Galling, Wear, Fatigue	Use specified lubricant, inspect for wear and corrosion	Conley 1990, p. 27
Cables	Polyethylene, Copper	Corrosion, Radiation Damage, Embrittlement	Apply advanced nonintrusive methods to trend degradation	Conley 1990, p. 27

The following recommendations are based on the studies by Conley (1990):

- High failure rates and failures found during testing could be reduced by updated preventive maintenance programs that include the most recent methods for detecting, monitoring. and controlling aging degradation. Further improvement could be made by upgrading codes and standards to include aging degradation considerations.
- The wear and aging degradation caused by fast starts could be reduced if the HPCI response time were relaxed to 60 seconds.
- The HPCI system would be running and available for immediate return to full service without a challenging startup if the systems were switched to recirculation to the coolant storage tank after water level recovery has been verified.
- Damage to the pump from deadhead operation could be prevented by modifying the minimum flow valve operating logic to ensure that the valve is open when the pump starts and closes when the pump is not running.

14.3 Equipment and Component Supports

Aging is of potential concern for support structures that are inside the containment and perform safety-related functions. These structures must be capable of resisting loads and load combinations to which they may be subjected, and this failure should not initiate a LOCA. If a LOCA occurs inside the containment, support structures mitigate the consequences of the accident by protecting the containment and other ESFs from effects of the accident (e.g., jet forces and whipping pipes). Support structures that are specifically considered in this subsection are RPV Supports and Snubbers.

14.3.1 Aging Concerns and Mechanisms

In this subsection, the aging concerns and mechanisms are addressed for the two different types of equipment and component supports, namely 1) RPV Supports and 2) Snubbers. Because of the significant differences in the operating characteristics of the two components, these will be treated separately and reported in Table 14.5 and Table 14.6.

Table 14.5 Aging concerns and mechanisms for RPV supports

Component	Material	Aging Concerns	Aging Mechanisms	References
Neutron Shield Tank at the Core Horizontal Midplane Elevation	A516 GR 60 Steel	Cracking Leading to Leakage	Neutron Embrittlement Corrosion	Hopkins 1987, Shah and Macdonald 1993
Column Support at the Core Horizontal Midplane Elevation	A36 Carbon Steel or A5331-B1 Steel	Cracking Leading to Loss of Support	Neutron Embrittlement	
Cantilever Support in the Active Height of the Core	A-36-69 and A193-GR B7 Steel	Cracking Leading to Loss of Support	Neutron Embrittlement	
Threaded Parts in Sliding Foot Assembly	Maraging Steels	Cracking	Corrosion	
Skirt Support	Carbon Steel	Ductile Rupture	Fatigue	

Table 14.6 Aging concerns and mechanisms for snubbers

Components	Materials	Aging Concerns	Aging Mechanisms	References
Mechanical Snubbers	Carbon Steel, Stainless Steel, Bronze	Internal Degradation, Spring Microcracking, and Locking.	Vibration, Fatigue, Corrosion	Hopkins 1987, Brown et al. 1992
Hydraulic Snubbers	Carbon Steel, Stainless Steel, Bronze, Thermo-plastics, and Elastomers	Degradation of Seals, Wear, Deformation of Metal Parts	High Temperatures, Moisture, Vibration, Wear	

RPV Supports

Of the four major types of RPV supports used in PWRs, the neutron shield tank supports and column supports are directly exposed to neutron flux from the reactor core beltline region over some portion of their supporting length. For these two types of support structures, the primary aging concern is neutron radiation-induced embrittlement. Radiation embrittlement of RPV steels, welds, and heat-affected zones adjacent to welds is discussed in detail in Chapter 2 of Volume 1 of this report. Normal operating temperatures in the supports are lower than those in the RPV; thus, the amount of embrittlement produced by a given neutron fluence would exceed that produced in the RPV.

Data from the High Flux Isotope Reactor (HFIR) vessel surveillance program indicate a substantial radiation embrittlement rate effect at low temperatures (–50°C [122°F]) for A212-B, A350-LF3, and A105-II, and corresponding welds (Cheverton et al. 1991). On the other hand, characterization of material from the Shippingport neutron shield tank (NST) indicated that the amount of embrittlement damage of A212 Grade B steel in a low-temperature, low-flux environment is not as large as that experienced by the HFIR surveillance capsules (Chopra and Shack 1990). Because the radiation spectrum experienced by vessel supports and the Shippingport NST are similar, the vessel supports are likely to experience embrittlement damage similar to that experienced by Shippingport NST. However, there are several unresolved issues regarding the embrittlement damage in a low-flux, low-temperature environment, some of which are currently being addressed.

A major type of PWR vessel support (the bracket type) and the skirt-type supports used for BWR (and a few PWR) vessels are not likely to receive a significant neutron fluence, even during an extended operating lifetime. The cantilever-type PWR vessel supports may or may not sustain a significant neutron fluence (Cheverton et al. 1989) depending on the specific design of the support structure and its location relative to the core region. An analysis of the potential impact of the apparent increase in low-temperature embrittlement, observed in the vessel surveillance program noted above indicates that a "short column" sup port that rests on steel cantilever beams may present the greatest potential for fracturerelated failure of the vessel supports (Cheverton et al. 1991). The potential for synergistic effects, where radiation embrittlement is of concern, has not been subjected to detailed examinations. Other factors that need to be considered include (Hopkins 1987)

- **Corrosion** - One of the factors present in all LWR containments is a greater-than-average humidity at elevated temperature, coupled with the presence of a radiation environment. The effect of the gamma radiation can be important in causing increased corrosion rates synergistically with the high humidity and temperatures. The long-term effects of such an environment on the integrity of the RPV supports should be examined because the total gamma dose alone on the supports will be over 5000 Mrads in the first 40 years of life. Reactor pressure vessels support corrosion during the original license period is not expected to be a problem; only minor local pitting has been observed to date.

- Radiation damage to nonferritic parts of the RPV support system - Some support systems depend on a dry lubricant that is located between the support and the RPV nozzle. Typically, such material has a radiation threshold dose on the order of 2×10^3 Mrads. Therefore, an evaluation should be made of the actual radiation levels the lubricant will receive and to determine if supplementation or replacement of the lubricant is needed.

- Stress corrosion cracking (SCC) of threaded parts in the sliding foot assembly - The threads are coated with Heresite. The threshold stress for initiation of SCC is 150 psi, while the applied tensile stresses'are calculated to be about 20 psi; therefore, SCC of the sliding foot assemblies is not expected.

- Fatigue - The skirt type supports for BWR RPVs are subject to fatigue because of the expansion and contraction cycles associated with the temperature- and pressure-induced expansion and contraction of the vessels during the plant startup/ shutdown cycles. However, the fatigue usage factor during the first 40 years of operation is expected to be well below 1.

Table 14.5 summarizes the aging concerns and mechanisms for RPV supports.

Snubbers

Snubbers are mechanical or hydraulic devices that limit the dynamic displacements of pipes or other components. The majority of piping snubbers are mechanical devices with load ratings 59,000 kg (130,000 lbs) or less, whereas equipment snubbers are almost exclusively hydraulic and are manufactured with load ratings up to 907,000 kg (2,000,000 lbs). Although snubbers can provide a valuable service, they have often been added, in response to an overly conservative stress analysis, at places where current design criteria would indicate that they are unnecessary.

An extensive review of the status of snubbers was made by Bush et al. (1986). They concluded that both hydraulic and mechanical snubbers are susceptible to failure from a variety of mechanisms, including those related to aging; however, the most important failure mechanism for a given snubber is highly dependent on the specific stressors applied to it, including the local environment and nature and frequency of the dynamic loads that are applied to it. This report included the following observations and recommendations in regard to specific tests:

- Breakaway force is sensitive to both vibration and extended periods of inactivity; inactivity may increase breakaway force levels substantially. Both conditions may exist and should be considered.

- The usual tendency is to minimize the dead band level to minimize impact loads in the snubbers and attached components. This tendency needs to be counter balanced against the increased tolerance to higher vibration levels at higher dead band levels.

- The spring rate or load displacement is an indication of the stiffness in the snubber; however, stiffness is controlled by the associated hardware attached to the structure, the snubber, and the component. Therefore, the spring rate of the snubber is only a part of the picture, and evaluations based on the cited values may not be valid.

- The various measured parameters are quite sensitive to the type of test and the test procedures. An acceptable snubber may be rejected or an unacceptable snubber may be accepted due to variability in test equipment and test procedures. This factor is not recognized in the various codes and standards. A definitive set of criteria should be developed to control this variable.

A preliminary NPAR evaluation of snubber aging (Brown et al. 1990) concluded, in part, that manufacturers' recommendations for maintenance of hydraulic snubbers are generally conservative while those for mechanical snubbers are not. The latest results from NPAR in-plant research (Brown et al. 1992) indicate that

- The performance of mechanical snubbers can be degraded by all the environmental influences, including elevated temperature, vibration, and moisture, by increasing drag and breakaway forces and by changing activation acceleration thresholds.

- The seal performance of hydraulic snubbers can be rapidly degraded by high temperatures in isolated areas. Radiation probably contributes less than originally hypothesized.

- Fluid leakage in hydraulic snubbers is commonly associated with leaking hydraulic fittings, though the amount of this fitting leakage that could be ascribed to the service environment could not be determined. However, a significant number of seal leaks were directly attributable to elevated temperatures rather than long-term exposure to normal environmental conditions.

Recently, the ASME standard on Operation and Maintenance of Nuclear Power Plants, OM-Part 4 (ASME 1990), has been proposed as a substitute for existing Technical Specification requirements for snubber ISI. The substitution of the OM-4 standard is currently under consideration by the NRC. If the substitution is approved by the NRC, a Generic Letter will be issued to allow nuclear power plants this regulatory option. The Phase I NPAR snubber research (Bush et al. 1986; Brown et al.

1990) has played an important role in the development of the snubber surveillance methods; and NPAR staff and subcontractors have maintained a direct interface. over the last 3 years, with the OM4 committee. An equally important impact is expected from the latest results of the NPAR in-plant research (Brown et al. 1992) which provides important information for understanding and managing snubber aging and recommendations for service life monitoring (Table 14.7)

Table 14.6 summarizes the aging concerns and mechanisms for snubbers.

14.3.2 Managing Aging Degradation

In this subsection, potential approaches for managing aging concerns and mechanisms are addressed for the two different types of equipment and component supports, namely 1) RPV Supports and 2) Snubbers.

Pressure Vessel Supports

Table 14.7 summarizes aging management practices for RPV supports.

As a result of his review of aging concerns for pressure vessel supports, Hopkins (1987) recommended that further studies be made to

- develop fracture toughness and strength assessment data for the RPV support steels irradiated at temperatures less than 232°C (450°F); develop a correlation of fracture toughness versus Charpy V-notch properties at temperatures less than 232°C (450°F) and as a function of displacements per atom and neutron fluence ($E > 1$ MeV)
- determine the range of radiation conditions (neutron spectra and flux levels) in and around shield tanks, and cantilever and column-type support structures
- investigate the effects of the expected radiation levels due to extended operation on the lubricants between the RPV nozzles and supports.

Snubbers

Brown et al. (1990, 1992) concluded that, historically, manufacturers' recommendations for hydraulic snubber seal and fluid replacement intervals are generally conservative and often result in unnecessary snubber overhauls or replacements. In contrast to this, the recommended 40-year maintenance-free service life of mechanical snubbers, originally recommended by snubber manufacturers, does not appear to be conservative enough.

Table 14.7 Managing aging degradation in RPV supports

Component	Materials	Aging Mechanisms	Management Options	References
Neutron Shield Tank at the Core Horizontal Midplane Elevation	A516 GR 60 Steel	Neutron Embrittlement, Corrosion	Monitoring	Hopkins 1987
Column Support at the Core Horizontal Midplane Elevation	A36 Carbon Steel or A5331-B1 Steel	Neutron Embrittlement	Monitoring and Sampling	
Cantilever Support in the Active Height of the Core	A-36-69 and A193-GR B7 Steel	Neutron Embrittlement	Monitoring and Sampling	
Threaded Parts in Sliding Foot Assembly	Maraging Steels	Stress Corrosion Cracking	Monitoring	
Skirt Support	Carbon Steel	Fatigue	Monitoring	

Failures resulting from long-term degradation may be minimized by scheduled maintenance (e.g., seal replacement or replacement of snubbers). However, because the probability of failure might actually increase due to handling or assembly errors, unnecessary maintenance or snubber replacement should be minimized. Practical methods are needed, therefore, for monitoring long-term degradation in both hydraulic and mechanical snubbers.

A limited number of snubbers fail from applications that are beyond their design capacity. These include high amplitude vibration, abnormally high temperatures, and transient loads. Short-term failures generally occur within one or two operating cycles. They can be reduced by modification of the environment, augmented surveillance, frequent maintenance, frequent replacement of snubbers, or retrofitting with more durable snubbers for a specific application.

Table 14.8 summarizes aging management practices for snubbers.

Snubber operability in the active (dynamic) mode is normally verified by measurement of activation level and/or release rate. The operability of a snubber in the passive mode (i.e., the ability of the snubber to allow free thermal motion) is usually determined during inservice tests by direct measurement of either breakaway force (the force required to initiate motion of the snubber) or by drag force (the force exerted by the snubber when stroked at a given velocity).

Pertinent discussions of Nondestructive Evaluation and Residual Life Assessment methods were provided in the recommendations by Brown et al. (1992) for service-life monitoring of snubbers. These recommendations included

- determination of snubber degradation or failure causes
- determination and documentation of operating environment
- augmented surveillance
- testing
- trending.

The service data for both hydraulic and mechanical snubbers are often incomplete in terms of documentation of environmental parameters and failure causes (Brown et al. 1990). In addition, inconsistencies exist in parameter measurement, inspection, testing, and documentation methods so that data from some plants cannot be readily combined or compared with data from others. Brown et al. (1992) noted several important considerations for trending: 1) test machines used for trending should provide a time trace of load and velocity, 2) establishing baseline data is essential for identifying trends, and 3) the parameters trended should be those that directly relate to the anticipated aging failure mode.

Table 14.8 Managing aging degradation in snubbers

Component	Material	Aging Mechanisms	Management Option	References
Mechanical Snubbers	Carbon Steel, Stainless Steel, Bronze	Vibration, Fatigue, Corrosion	Monitor, Test and Change Design and Operating Procedure	Brown et al. 1992
Hydraulic Snubbers	Carbon Steel, Stainless Steel, Bronze, Thermo-Plastics, Elastomers	High Temperature, Moisture, Vibration, Wear	Monitor and Trend Performance Testing, Design Changes	Brown et al. 1992

14.4 References

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15 Electrical Components

The electrical components considered in this section include relays and circuit breakers. Cables connectors and splices are covered in Part 1 Section 6. Other related sections in this Part include Sections: 3- Reactor Protection System; 8- Instruments and Control Power Systems; 16.1-Resistance Temperature Detectors; 20-Bistables and Switches and; 21-Motors and Motor control Centers.

15.1 Relays

Relays are solid state devices used in protective and control applications in **NPPs**. There are five categories of relays: protective, auxiliary, control, time delay or timing, and electronic.

Protective relays detect power overloads or degraded conditions in the plant power system and initiate the opening of circuit breakers to isolate the affected portion from the electrical distribution system and, thereby, prevent damage to protected equipment (motors, buses, and transformers). The contacts of most protective relays are limited to currents between 0.3 and 3.0 amps and are not, therefore, capable of handling the electrical load associated with completion of the protective action. There are many different types of protective relays, but the most commonly used are undervoltage, instantaneous overcurrent, time overcurrent, and differential protective relays.

Auxiliary relays, which can have contacts rated to 35 amps, supplement protective relays in transmission and distribution systems to carry the heavier electrical loads required to operate circuit breaker trip coils. Auxiliary relays are normally actuated by the contacts of protective relays.

Control relays are used in the logic and protective action initiation systems. Control relays are two-position relays that transfer position when their coils are energized. They may be constructed with solenoids or armatures, however, solenoid types are more common.

Time delay relays usually consist of a control relay with a timing device attached that, when energized or **de-energized**, delays the change in position of the relay contacts for a specified period, as when used to delay a trip function to avoid spurious trips. In many plants, time delay relays are also used in the emergency power system to sequence loads connected to the diesel generator.

Electronic relays are solid state devices that are used for protective or control relay applications. This type of relay is relatively new in nuclear applications and is not widely used. There has been use in some limited applications, such as motor control relays and in applications where high cycling causes mechanical relays to fail frequently.

15.1.1 Aging Concerns and Mechanisms

Toman et al. (1987) did an extensive review of data on the designs, functions, and aging of relays. They concluded that relay components are aged by numerous stressors that, with time, will cause relay materials to degrade. Discussed below are the materials used in relay components and their aging degradation mechanisms.

While relays are usually located in sealed cabinets and, therefore, in relatively mild environments, they are subjected to a variety of mechanical, electrical, thermal, and environmental stressors. The symptoms of such degradation may include changes in response time (slowing of control relays or variations in the time delay for time delay relays), in coil characteristic (inrush and holding currents, and insulation resistance), or in contact characteristics (resistance across closed contacts). The various types of relays are generally constructed of the same materials, though the induction disc relays and time delay relays use some different materials.

Relays are subjected to a variety of mechanical, electrical, thermal, and environmental stressors that contribute to degradation. After this degradation, relays may fail when energized at normal design voltages. Aging concerns and mechanisms for relays are listed in Table 15.1.

Table 15.1 Aging concerns and mechanisms for relays

Component	Materials	Aging Concerns	Aging Mechanisms	References
Relay Case	Phenolic, Lexan'	Leakage and Internal Contamination, Binding	Embrittlement, Chemical Reactions, Vibration, Thermal Damage	Toman et al. 1987
	Aluminum, Steel	Internal (e.g. dirt) Contamination	None Significant	
Coil wire	Polyamide-imide Insulated Wire	Dielectric Breakdown, Shorts	Radiation, Oxidation, Thermal Damage, Inductive Surges	
	Copper Wire	Increased Resistance, Loosening, Shorts	Corrosion, Thermal Cycling, Leakage	
Coil Spool	Zytel,' Nylon, Lexan'	Dielectric Breakdown, Shorts	Radiation, Oxidation, Thermal Damage, Inductive Surges	
Coil Coating	Polyester Tape, Fiberglass Tape, Varnish	Dielectric Breakdown, Shorts	Radiation, Oxidation, Thermal, Inductive Surges, Humidity	
Contact Carriers	Phenolic, Zytel,[1] Nylon, Delrin'	Shape Change	Thermal Damage	
Contacts	Silver	Corrosion, Oxidation of Contacts, Contact Insulation. Loss of Contact Material	Oxidation, Contamination (e.g., dirt), Arcing and High Cycle Rate	
Coil lead Wires	Teflon' Silicon Rubber, Tefzel[1]	Dielectric Breakdown, Shorts	Radiation, Oxidation, Thermal Damage, Inductive Surges	
	Copper Wire	Loosening Resulting in Ohmic Heating and Burnout	Vibration, Thermal Cycling	
Cams	Delrin' Metal	Wear, Corrosion, Binding	Corrosion, Contamination	
Timing Circuits	Resistance/Capacitance Networks With Solid State Components	Failure, Setpoint Drit?	Radiation, Oxidation, Thermal Damage, Power Surges	
Timing Diaphragms	Silicon Rubber	Rupture, Leakage, Plugging, Drift	Radiation, Oxidation, Thermal Damage, Contamination	
Plunger or Armature	(Not Specified)	Binding, Mechanical Failure	Contamination, High Cycle Fatigue, Wear	

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The most predominate stress mechanism is electrical relays appears to the thermal degradation (Toman et al. 1987). Thermal degradation impacts the non-metallic parts through increasing chemical reactions and/or through softening or melting of the material. Solenoids in a continuous energized state or in an enclosed cabinet or subjected to other elevated temperatures are more susceptible to thermal induced failures. High temperature relays are available and when required high temperature wire leads must also be used.

Environmental conditions that contribute to relay degradations, include humidity, dust, dirt, oxidation and chemical contaminates. These conditions can affect the operability of moving parts, heat dissipation, contact corrosion and insulation integrity. Enclosed relays have a reduced probability of failure from environmental sources at the cost of increased thermal degradation.

Moving parts within the relays are susceptible to normal mechanical wear. Thermal and environmental factors can accelerate the mechanical stresses and accelerate degradation. As intuitively obvious, high cycle relays are most susceptible to mechanical wear and fatigue. Relays, lead wires and connections exposed to frequent vibration or repeated movement lead wires could experience excessive wear and fatigue.

Electrical stresses under normal design voltages and relay operability do not result in shortening the relay life (Toman et al 1987). Under degraded conditions or voltage spikes can cause shorting of the coils and/or excessive contact wear. An inductive surge created by an interruption of power to a direct current coil can also cause shorting.

15.1.2 Managing Aging Degradation

The components of a successful program to manage aging degradation are broadly twofold: **1)** inservice inspection, surveillance, and monitoring methods (incorporating non-destructive examination and residual life assessments, where appropriate, as well as parameter trending and record-keeping) to assess the magnitude and rate of aging degradation; and **2)** control measures to mitigate the adverse impacts of component aging on plant safety and capacity factors. These methods for managing aging degradation are discussed below and summarized in Table **15.2.**

15.1.2.1 Inservice Inspection, Surveillance, and Monitoring

Gleason (1992) examined a variety of inservice ISMM for aged and degraded relays. Both current nuclear industry ISM practices and improved ISM methods were evaluated. Several of these methods were found to be effective in detecting aging in relays.

For protective relays, **19** methods were evaluated and **11** were found to be effective in detecting aging. Of these **11** methods, the common nuclear plant ISM practices were visual inspection, time/current characteristic, induction/overcurrent pickup, target and seal-in, and operating current. When these common practices were properly performed, all methods were effective at detecting aging except for the operating current method. Moreover, not all the current methods were equally sensitive for degraded relays from different manufacturers. The improved ISM method of infrared temperature measurement, done by pyrometer or scanner, was more sensitive to degraded conditions caused by dirt, overheating, and contact damage than the current practice and about as sensitive as the current practice when degradation was due to loose connections. For protective relays, infrared temperature measurement is recommended in addition to the current plant practices and should be performed with the cover off the relay and with the relay energized.

For auxiliary relays, **16** ISM methods were evaluated and **14** were found to be effective in detecting aging. Of these **14** methods, the common nuclear plant ISM practices were visual inspection, pick-up voltage, and drop out voltage. When these common practices were properly performed, all three methods were effective at detecting aging. However, the current methods were not sensitive to many of the degraded conditions. The improved ISM methods of infrared temperature measurement, vibration testing, and acoustic testing were each more sensitive to degraded conditions than current practice. The improved ISM method of infrared temperature measurement, by pyrometer or scanner, was more sensitive to degraded conditions caused by dirt, overheating, blocked armature, and loose connections than the current practice of pick-up voltage and drop out voltage. Vibration testing, which gives a vibration signature analysis of the transient occurring during change of state of the control relay, was more sensitive than the current practice to the degraded conditions of loose connections, contact damage, blocked annature, overheating, increased coil resistance, shorted coil turns, and dirt accumulation. For auxiliary relays, infrared temperature measurement and vibration testing are recommended in addition to the current plant practices.

Table 15.2 **Managing** aging **degradation of relays**

Component	Materials	Aging Mechanisms	**Managing Options**	References
Relay Case	Phenolic, Lexan[1]	Embrittlement. Chemical Reactions. Vibration, Thermal Damage	Maintain or Improve Inspection Methods: • Protective relays: visual inspection, time/current characteristic, induction/overcurrent pickup, target and seal-in, and infrared temperature measurement • Auxiliary relays: visual inspection, pick-up voltage, drop out voltage, infrared temperature measurement, and vibration testing • Control relays: visual inspection, pick-up voltage, drop out voltage, infrared temperature measurement, and vibration testing • Electronic relays: visual inspection, overcurrent sensing pick-up, instantaneous overcurrent, and vibration testing, limited to areas of low noise • Timing relays: visual inspection, pick-up voltage, and timing tests, infrared temperature measurement, inrush current, and vibration testing	Gleason 1992
	Aluminum, Steel	None Significant		
Coil wire	Polyamide-imide insulated wire	Radiation, Oxidation. Thermal Damage. Inductive Surges		
	Copper wire	Corrosion, Thermal Cycling, Leakage		
Coil Spool	Zytel,[1] Nylon, Lexan[1]	Radiation, Oxidation. Thermal Damage, Inductive Surges		
Coil coating	Polyester Tape, Fiber-glass Tape, Varnish	Radiation, Oxidation, Thermal, Inductive Surges, Humidity		
Contact Carriers	Phenolic, Zytel.[1] Nylon. Delrin[1]	Thermal Damage		
Contacts	Silver	Oxidation, Contamination (e.g., dirt), Arcing and High Cycle Rate		
Coil lead Wires	Teflon,[1] Silicon Rubber, Tefzel[1]	Radiation, Oxidation, Thermal Damage, Inductive Surges		
	Copper Wire	Vibration, Thermal Cycling		
Cams	Delrin[1] Metal	Corrosion, Contamination		
Timing Circuits	Resistance/Capacitance Networks with Solid State Components	Radiation, Oxidation, Thermal Damage, Power Surges		
Timing Diaphragms	Silicon Rubber	Radiation, Oxidation, Thermal Damage, Contamination		
Plunger or Armature	(Not Specified)	Contamination, High Cycle Fatigue, Wear		

[1]Trademark of E.I. DuPont de Nemours & Company.

For control relays, 16 **ISM** methods were evaluated and 11 were found to be effective in detecting aging. Of these 11 methods, the common nuclear plant **ISM** practices were visual inspection, pick-up voltage, and drop out voltage. When these common practices were properly performed, all three methods were effective at detecting aging. However, the current methods were not sensitive to most of the degraded conditions. The improved **ISM** methods of magnetic flux, infrared temperature measurement, vibration testing, and acoustic testing were sensitive to additional degraded conditions. Also, each was sensitive to some degraded condition for which current practice was insensitive. The improved **ISM** method of infrared temperature measurement, by pyrometer or scanner, was more sensitive to degraded conditions caused by dirt, overheating, short coil turns, and loose connections than was the current method of pick-up voltage and drop out voltage. Vibration testing was more sensitive than the current practice to the degraded conditions of loose connections, contact damage, blocked armature, and overheating. For control relays, infrared temperature measurement and vibration testing are recommended in addition to the current plant practices.

For electronic relays, 12 ISM methods were evaluated and 4 were found to be effective. Of these 4 methods, the common nuclear plant ISM practices were visual inspection, overcurrent sensing pick-up, and instantaneous overcurrent. When these common practices were properly performed, all three methods were effective at detecting aging. The improved ISM method of vibration testing, though limited to areas of low noise because of its low signal, was sensitive to all degraded conditions.

For timing relays, 17 ISM methods were evaluated and 13 were found to be effective in detecting aging. Of these 13 methods, the common nuclear plant ISM practices were visual inspection, pick-up voltage, and timing tests. When these common practices were properly performed, all three methods were effective at detecting aging. However, the current methods were not sensitive to many of the degraded conditions. The improved ISM methods of infrared temperature measurement, inrush current, and vibration testing were each more sensitive to degraded conditions than current practices. The improved ISM method of inrush current, was more sensitive to degraded conditions caused by dirt accumulation, contact damage, and shorted coil turns than the current practice. Vibration testing was more sensitive than the current practice to the degraded conditions of loose connections, contact damage, blocked armature, overheating, increased coil resistance, shorted coil turns, and dirt accumulation. For timing relays, infrared temperature measurement, inrush current, and vibration testing are recommended in addition to the current plant practices, while the pick-up voltage test is recommended for deletion.

15.1.2.2 Mitigation

Gleason (1992) suggested that the methods determined to be effective in detecting aging in relays were also capable of mitigating that aging. That is, detection of aging degradation would identify the need for an appropriate maintenance action; this action would then be performed to mitigate the observed degradation. These maintenance practices are summarized in Table 15.2.

15.2 Circuit Breakers

Circuit breakers (CBs) have two basic functions: switching and fault interruption. When switching, the CB is used to energize or deenergize loads and to transfer load groups from one power source to another. During switching, the currents being made and broken are within the normal rated current of the CB. When the CB is being used in its protective (i.e., fault interruption) mode, the CB interrupts large fault currents associated with short circuits in the connected, loadside equipment. Most CBs can be used as both switching and fault interrupting devices, the specific application determining which function is important.

Only those CBs associated with the emergency buses are safety-related. Most safety-related CBs are in the low voltage and medium voltage classes, 480 Vac and 4160 Vac (or, in some plants, 13.6 kV), respectively. (The high voltage CBs associated with the main and startup transformers, which are of a totally different type and style from the safety-related CBs, are not considered here.) Safety-related CBs may be divided into two generic types: molded-case CBs and CBs associated with metal-clad switchgear. Molded-case CBs are used to supply individual circuits and feeders for low voltage AC and DC distribution systems having voltages of 480 V and below for small loads. The breakers are enclosed in a phenolic molded housing that, generally, is sealed at the factory, and require little or no maintenance. The metal-clad switchgear CBs are predominantly associated with the 4160- (or 13.6 kV) and 480-V emergency loads buses. The metal-clad CB is much larger than the molded-case CB and is associated with a large plug-in bus system that is contained in a metal housing, hence the name "metal-clad." The bus system contains a number of cubicles, some reserved for instrumentation and transformers, and the remainder reserved for the CBs. The CBs can be easily removed from their cubicles for testing and maintenance. Circuit breakers associated with the DC system and with the AC vital buses may be molded-case or metal-clad, depending on the capacity and design of the system.

Circuit breakers are complex electromechanical devices that must reliably perform the following functions: 1) close the current path and carry the steady-state load current without overheating; 2) maintain sufficient contact pressure when closed to prevent a high-resistance path between contacts; 3) rapidly open the contacts under fault conditions so that current interruption does not result in excessive burning of the contacts; and 4) always provide adequate phaseto-phase and phase-to-ground insulation. Circuit breakers have to be located in mild environments. If a CB is located in a steam or spray environment, the power path will flash over and, if subjected to the high temperature of an accident, a thermal cascade failure of its insulators could occur. However, even in mild environments, meeting the functional requirements noted above imposes stresses on CBs that can lead to aging-induced failures.

15.2.1 Aging Concerns and Mechanisms

Toman et al. (1987) did an extensive review of data on the designs, functions, and aging of CBs, and concluded that CB components are aged by numerous stressors, which may in time lead to their failure. Discussed below are the materials used in CB components and their aging degradation mechanisms.

While CBs are usually located in mild environments, they are subjected to a variety of mechanical, electrical, thermal, and environmental stressors. These stressors include self-induced vibration and shock forces, electrical and magnetic forces, resistive heating, corrosion, and erosion. Therefore, all components must have sufficient mechanical and electrical strength; current-carrying parts must have high conductivity with good arcing corrosion resistance of the contacts; and insulating materials must have high dielectric strength and flame retarding properties.. As details about CB materials are often considered proprietary by manufacturers, the following discussion of typical materials or material types used in CB components is from information available from Brown Boveri (Bulletin 3.2.1-1B)[1] unless otherwise noted.

The main contacts are made of a silver alloy having high electrical conductivity. Arcing contacts use a high refractory silver alloy for minimum deterioration during arcing while maintaining good electrical conductivity. Plating of arcing contacts is commonly used to increase the dielectric strength of the contact gap following a current-zero in the interruption process (Bogert 1962).

Buses and current-carrying components are usually made of a hardened copper alloy, insulated with epoxy, with the main bus carried through the wall of the frame with porcelain supports embedded in polyester glass. Most parts of the operating mechanism are made of a high-quality brass or phosphor bronze and steel, with the charging springs in the stored energy mechanism made of high-quality spring steel (Toman et al. 1987).

Arc chutes, which contain the arc during the interruption process, are typically made of a high impact track-resistant polyester, but may also be made from a glazed ceramic material (Heinmiller et al. 1983).

The primary disconnects are insulated with a polyester laminate or by porcelain housings mounted on polyester glass preforms bonded with an epoxy compound. Polyester glass supports the main bus and other continuous current components, serves to isolate the components from ground and, along with epoxy, provides an interphase bamer assembly to isolate the phases.

Circuit breakers are subjected to a variety of mechanical, electrical, thermal, and environmental stressors that contribute to CB degradation; these are listed in Table 15.3.

Table 15.3 Aging concerns and mechanisms for circuit breakers

Component	Materials	Aging Concerns	Aging Mechanisms	References
Mechanism Lubricants	Molybdenum Disultide and Petroleum-based Grease	Wear of Trip Mechanism Bearings	Lubricant Evaporation	Toman et al. 1987
Contacts	Silver Alloy On Copper base	Damage To Contact Support Insulation Causing Phase-To-Round Fault	Resistive Heating	
		Contact Degradation	Fatigue, Wear	
Insulation Materials for Power Path	Polyester, Glass Fiber-Filled Epoxy Resin, And Phenolic	Decreased Insulating Capability Of Electrical Insulating Components	Contact Material Vaporization	

[1] Brown Boveri Bulletin 3.2.1-1B. I-T-E Type HK Metal-Clad Switchgear. p. 10-11, Asea Brown Boveri (ABB), Stamford, Connecticut.

15.2.2 Managing Aging Degradation

The components of a successful program to manage aging degradation are broadly twofold: **1)** inservice inspection, surveillance, and monitoring methods (incorporating non-destructive examination and residual life assessments, where appropriate, as well as parameter trending and record-keeping) to assess the magnitude and rate of aging degradation; and **2)** control measures to mitigate the adverse impacts of component aging on plant safety and capacity factors. These methods for managing aging degradation are discussed below and summarized in Table 15.4.

15.2.2.1 Inservice Inspection, Surveillance, and Monitoring

Gleason **(1992)** examined a variety of inservice ISMM for aged and degraded molded-case and metal-clad circuit breakers. Both current nuclear plant ISM practices and improved ISM methods were evaluated. Several of these methods were found to be effective in detecting aging in CBs.

For molded-case CBs, the common nuclear plant ISM practices evaluated were visual inspection, instantaneous trip, pole resistance, insulation resistance, current hold-in (100 and 135% rated), and 300% overcurrent. When these common practices were properly performed, all methods, except for insulation resistance and mechanical actuation, were effective at detecting aging. Insulation resistance is useful for ensuring high-integrity connections and, thus, personnel safety after maintenance is performed. The instantaneous trip test is effective when performed below and above the instantaneous trip range. In addition, the improved ISM methods of infrared temperature measurement and vibration testing were found to be effective in detecting aging in molded-case CBs. Infrared temperature measurements, by pyrometer or scanner, detected significant temperatures before damage to internals could occur. Vibration testing was the only method capable of detecting all the test degraded conditions. Infrared temperature measurement and vibration testing are recommended in addition to current plant practices.

For metal-clad CBs, the common nuclear plant ISM practices evaluated were visual inspection, mechanical actuation, instantaneous trip, pole resistance, insulation resistance, long time delay overcurrent, short time delay overcurrent, and lubrication inspection, which is a part of visual inspection. When these common practices were properly performed, all methods, except for insulation resistance, were effective at detecting aging. The improved ISM methods of infrared temperature measurement and vibration testing were found to be effective in detecting aging in metal-clad CBs. Infrared temperature measurements, by pyrorneter or scanner, could detect significant temperatures due to loose connections that, during the long time delay function of the trip device, could result in overheating of components. Vibration testing was the only method capable of detecting all the test degraded conditions and is also useful during trip tests. Infrared temperature measurement and vibration testing are recommended in addition to current plant practices.

15.2.2.2 Mitigation

Maintenance practices recommended by the manufacturers of the CBs are summarized by **Toman et al. (1987).** Gleason **(1992)** suggested that the methods determined to be effective in detecting aging in CBs were also capable of mitigating that aging. That is, detection of aging degradation would identify the need for an appropriate maintenance action; this action would then be performed to mitigate the observed degradation. These maintenance practices are summarized in Table **15.4.**

Table 15.4 Managing aging degradation of circuit breakers

Component	Materials	Aging Mechanisms	Inservice Inspection. Surveillance, and Monitoring	**Mitigation**
Mechanism Lubricants	Molybdenum Disulfide and Petroleum-Based Grease	Lubricant Evaporation	Molded-case Cbs': • Current methods: visual inspection, pole resistance, 100% rated current hold-in, 135% rated current hold-in, and 300% overcurrent, with insulation resistance to ensure good connections and instantaneous trip performed below and above the instantaneous trip range • Improved methods: infrared pyrometry or scanning, and vibration testing Metal-clad CBs[2]: - Current methods: visual inspection (including lubrication inspection, mechanical actuation, instantaneous trip, pole resistance, insulation resistance, long time delay overcurrent, short time delay overcurrent, with insulation resistance to ensure good connections • Improved methods: infrared pyrometry or scanning, and vibration testing.	The recommended ISM methods, being effective in detecting aging, are capable of mitigating aging.''. Additional, specific mitigation methods include''' • Molded-case, single phase, low-voltage CBs - sufficiently inexpensive for corrective action to be by replacementO'. • Molded-case, multi-phase CBs with removable covers - small amount of light oil or grease at wear points' - file or sand pined contacts[4]. • Metal-clad CBs periodically at user-defined intervals, along with tests and inspections[s,d] - thorough cleaning - check primary contacts for wear and lightly lubricate them - replace undervoltage trip attachments for reactor trip circuits for Westinghouse PWR based on number of operations for the device[9] - evaluate and adjust spring charging mechanisms?
Contacts	Silver Alloy On Copper Base	Resistive Heating		
		Fatigue, Wear		
Insulation Materials For Power Path	Polyester, Glass Fiber-Filled Epoxy Resin, And Phenolic	Contact Material Vaporization		

[1]Gleason 1992; pp. 5-16 to 5-18.
[2]Gleason 1992; pp. 5-18 to 5-19.
[3]Toman et al. 1987; paragraph 3.8, p.139.
'General Electric GET-2779G.
[5]Westinghouse I.B. 33-790-1E.
[6]General Electric GET-7303C.
[7]Westinghouse I.BV. 24-Y-7269
'General Electric GET-1802W.
[9]Toman 1982

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16 Components of Instrumentation and Control Systems

The components considered in this section are resistance temperature detectors and pressure sensors. Both types of instrumentation are widely used in nuclear power plants at locations often dictated by the system being measured.

16.1 Resistance Temperature Detectors

Resistance temperature detectors (RTDs) are integral components of LWR safety systems. In order for the safety system to function properly, RTD indications must be accurate and timely. The two main types of RTDs are direct immersion, or wet-type, and thermowell-mounted, or well-type. A typical RTD consists of a sensing element, with extension wires, sealed and insulated within a metallic sheath. The sheath material is stainless steel or inconel, while the sensing element is a fully annealed platinum wire. A well-type RTD averages 30 to 60 cm (12 to 24 inches) in length, 1 to 2 cm (0.4 to 1 inches) in diameter, and weighs between 300 and 3000 grams (0.5 to 7 Ibs). A wet-type RTD is smaller, averaging 12 to 18 cm (4 to 7 inches) in length, 0.6 'to 1 cm (0.25 to 0.4 inches) in diameter, and between 100 and 250 grams (0.2 to 0.5 Ibs).

16.1.1 Aging Concerns and Mechanisms

Environmental, or normal, stressors act upon RTDs, such as heat, humidity, vibration, temperature cycling, and mechanical shock. Abnormal stressors result from handling, installation, maintenance, and design or manufacturing flaws. Table 16.1 shows these stressors along with affected components and resultant aging mechanisms and aging concerns.

Table 16.1 Aging concerns and mechanisms for resistance temperature detectors'

Stressors	Components	Aging Mechanisms	Aging Concerns
Heat	Platinum Element	Chemical Contaminate Metallurgical Changes	Calibration Shift
	Insulation Material	Strain Caused by Thermal Expansion	Gap/crack Formation Response Time Degradation
	Seal	Strain Caused by Thermal Expansion	Moisture Allowed into the Sheath
Humidity	Insulation Material	Insulation Breakdown	Calibration Error Noisy RTD Output
Vibration and Mechanical Shock	Platinum Element	Cold Working	Calibration Shift Response Time Increase
	Spring	Loosening (thermowell only)	Response Time Change
	Insulation Material	Insulation Breakdown	Response Time Degradation
Temperature Cycling	Platinum Element	Strain Caused by Thermal Expansion	Calibration Shift
	Insulation Material	Strain Caused by Thermal Expansion	Response Time Change
1Hashemian et al. 1990; pp. 24-35.			

With normal aging, temperature effects are most significant. By the thermal expansion mechanism, RTD materials with different thermal expansion coefficients are strained with rising temperatures to form gaps and cracks. Long-term exposure to high temperatures can result in chemical contamination of the platinum sensing element. Temperatures above 420°C (788°F) cause calibration shifts due to metallurgical changes, such as grain growth. Insulation breakdown comes from vapor entering the sheath at high temperatures and leads to noisy RTD output and calibration error.

Vibration-induced cold working of the platinum sensing element results in calibration shifts and causes the RTD to gradually move out of the thermowell and increase response time. Also, vibration can alter response times by loosening the spring or by breaking down insulation when combined with high temperatures.

Abnormal stressors lead to performance problems, such as 1) slow response times because of inadequate RTD insertion, 2) failures due to rough handling or storage in humid environments, and 3) calibration inaccuracy from RTDs cut too short.

16.1.2 Managing Aging Degradation

Table 16.2 displays the management options for handling the aging mechanisms and concerns previously described. There are four options: 1) periodic tests, 2) pre-installation screening, 3) recalibration for inactive or stored RTDs, and 4) scheduled replacements (Hashemian et al. 1990).

Periodic tests should be done near the end of a fuel cycle prior to a refueling outage so that any problems can be resolved during an outage. Testing can be done more frequently if there are plant specific reasons or the RTDs are suspected of deficiencies in design, fabrication, or installation. Testing should be performed on line using methods developed and validated for NPP use. The accuracy of RTDs is to be assessed by full calibration, while response times are to be determined by Loop Current Step Response (LCSR) tests. The LCSR test should be done at or near normal operating conditions and can be supplemented by self heating tests, which detect gross changes in RTD characteristics.

Table 16.2 Managing aging degradation for resistance temperature detectors[1]

Stressors	Components	Aging Mechanisms	Aging Management
Heat	Platinum Element	Chemical Contaminate Metallurgical Changes	• Perform full calibrations and loop current step response (LCSR) tests once per fuel cycle • Screen RTDs prior to installation using a "bum-in" program for calibration and a laboratory response time test • Recalibrate any RTD that has been inactive for over 2 years • Replace any RTDs which: (1) shift by more than 1°C or consistent, drift in one direction during calibration tests (2) have unacceptably slow response times during response testing
	Insulation Material	Strain Ccaused by Thermal Expansion	
	Seal	Strain Caused by Thermal Expansion	
Humidity	Insulation Material	Insulation Breakdown	
Vibration and Mechanical Shock	Platinum Element	Cold Working	
	Spring	Loosening (thermowell only)	
	Insulation Material	Insulation Breakdown	
Temperature Cycling	Platinum Element	Strain Caused by Thermal Expansion	
	Insulation Material	Strain Caused by Thermal Expansion	

[1] Hashemian et al. 1990; pp. 161-165, 180.

Pre-installation screening provides for each RTD to be calibrated using a "bum-in" program and response time tested in a laboratory (Hashemian et al. 1987). . Any RTD showing instability during calibration or having a long response time should not be used.

Recalibration is necessary for any RTDs that have been stored for over 2 years. This procedure also holds true for any RTDs that have been inactive for over 2 years, such as those installed in a non-operating plant.

Replacement schedules are based on performance problems identified by the periodic in-plant tests described above. Based on calibration tests, RTDs should be replaced which shift by more than 1°C (2°F) or consistently drift in either direction, positive or negative. Based on response time tests, direct immersion RTDs having unacceptably slow response times must be replaced. However, well-type RTDs with slow response times can be cleaned and tried again before replacement becomes necessary.

16.2 Pressure Transmitters

Pressure transmitters provide important signals for the control and safety of NPPs. An average NPP uses 100 to 200 pressure and differential pressure transmitters to measure the process pressure, level, and flow in the primary and secondary systems of the plant. Pressure transmitters can be characterized by their class, type, and manufacturer. The two classes of transmitters are mechanical and electromechanical. Both classes convert the applied pressure to a displacement through an elastic sensing element, but the electromechanical class also uses a strain gauge or differential transformer to convert the displacement to an electrical signal. The three types of sensing elements for these classes are Bourdon tube, bellows, and diaphragm, while the four leading manufacturers are Barton, Foxboro. Rosemount, and Tobar.

A typical pressure sensing system consists of 1) root valves at the process end of the sensing line as well as isolation and equalizing valves at the transmitter, 2) sensing lines which bring the pressure information from the process to the sensor, 3) mechanical system which consists of the sensing element and the associated hardware. 4) signal conditioning components inside the transmitter, and 5) power supply, external signal conditioning equipment, and reactor trip circuitry. (Hashemian et al. 1993a).

16.2.1 Aging Concerns and Mechanisms

Stressors acting upon the pressure transmitters are temperature, radiation, pressure, chemical, mechanical, and manufacturing flaws. Table 16.3 shows the aging concerns and mechanisms which result from these stressors to degrade transmitter components. The aging mechanisms are often synergistic in nature, requiring a combination of stressors to invoke degradation. This is reflected in the description of aging processes in the following paragraph and in Table **16.3** by the listing of enhancing stressors along with the aging mechanisms they accompany.

Thermal fatigue creates drifting in damping resistors because of thermal cycling, radiation, and vibration. Diffusion, initiated by heat, radiation, and humidity, can cause changes in the values of electronic components. Radiation combined with heat can embrittle seals to allow moisture in-leakage or produce a viscosity increase in the fill fluid. Pressure enhanced by manufacturing flaws can cause a partial or total loss of fill fluid, while pressure enhanced by vibration can change the stiffness of the sensing element. Corrosion of the mechanical linkages can generate wear, friction, and sticking which is further aggravated by pressure fluctuations and surges. Work hardening, intensified by pressure cycling, can alter the diaphragm spring constant. Blockage of capillary tubes and other passageways can restrict the flow of till fluid.

16.2.2 Managing Aging Degradation

Table 16.4 summarizes effective programs for the management of aging caused by the mechanisms previously described. The primary option for aging management is periodic testing, both calibration and response time, which determines if transmitter replacement is necessary. In administering these tests, the most important question to answer is whether the test should be performed on line or off line. Onliie testing requires sophisticated computer monitoring methods, but permits remote testing at normal operating conditions. Offline testing, however, involves measurements taken during an outage.

Table 16.3 Aging concerns and mechanisms for pressure transmitters[1,2]

Stressors	Components	Aging Mechanisms	Aging Concerns
Temperature (heat or cycling)	Damping Resistors	Thermal Fatigue (enhanced by radiation and vibration)	Drifi
	Electronics	Diffusion (enhanced by radiation and humidity)	Changes in Valves of Electronic Components
Radiation	Fill Fluid	Viscosity Increase (enhanced by heat)	Fill Fluid Degradation
	Seals	Thermal Aging Thermal Stress Fatigue Fouling	Moisture Allowed into Transmitter Electronics
Pressure (over pressurization or cycling)	Fill Fluid	Degradation/Leaking (enhanced by manufacturing flaws)	Partial or Total Loss of Fluid
	Sensing Element	Deformation (enhanced by vibration)	Changes in Stiffness
Chemical	Mechanical Linkages	Corrosion/Oxidation (enhanced by pressure fluctuations and surges)	Wear, Friction, and Sticking
Mechanical	Diaphragm	Work Hardening (enhanced by pressure cycling)	Changes in Spring Constant
Manufacturing Flaws	Capillary Tubes and Other Passageways	Blockage	Restriction of the Flow of Fill Fluid

[1]Hashemian et al. 1993a; Table 9-1, pp. 131-134.
[2]Hashemian et al. 1989; pp. 17-23.

Table 16.4 Managing aging degradation for pressure transmitters[a]

Stressors	Components	Aging Mechanisms	Aging Management
Temperature (heat or cycling)	Damping resistors	Thermal Fatigue (enhanced by radiation and vibration)	• Perform off-line calibrations tests once per fuel cycle • Perform response time tests on every channel once per fuel cycle • Blow, or purge, sensing lines during every refueling outage or as indicated necessary by noise analysis • Surveillance test signal conditioning equipment and reactor trip circuiting once a month • Implement enhanced surveillance program and increased on-line monitoring for certain Rosemount transmitter models
	Electronics	Diffusion (enhanced by radiation and humidity)	
Radiation	Fill Fluid	Viscosity Increase (enhanced by heat)	
	Seals	Thermal Aging Thermal Stress Fatigue Fouling	
Pressure (over pressurization or cycling)	Fill Fluid	Degradation/Leaking (enhanced by manufacturing flaws)	
	Sensing Element	Deformation (enhanced by vibration)	
Chemical	Mechanical Linkages	Corrosion/Oxidation (enhanced by pressure fluctuations and surges)	
Mechanical	Diaphragm	Work Hardening (enhanced by pressure cycling)	
Manufacturing Flaws	Capillary Tubes and Other Passageways	Blockage	

[1]Hashemian et al. 1993a; pp. 239-254 and pp. 281-307.

For calibration tests, conventional offline methods must be used. New online techniques are under development, but will not be feasible for a few more years (Hashemian et al. 1993b). For response time tests, online methods should be used for most transmitters. Two acceptable online tests for response time are the Power Interrupt (PI) test and noise analysis. The PI test is limited to force-balance pressure transmitters and noise analysis is unacceptable for containment transmitters in PWRs. Offline techniques, such as ramp or step testing, can be used when online methods are impossible.

Calibration and response time tests should be performed once every fuel cycle. Response time tests must be done on every channel. Sensing lines should be blown, or purged, at every refueling outage or as indicated necessary by noise analysis. Signal conditioning equipment and reactor trip circuitry should be surveillance tested about once a month, as well.

Oil loss has been a recurring problem for certain models of Rosemount pressure transmitters. If these models are used in a plant, an enhanced surveillance program should be implemented along with increased online monitoring (Hashemian et al. 1993a).

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17 chemical and Volume Control System

The chemical and volume control system (CVCS) performs the following functions:

- fills the RCS
- provides a source of high pressure water for pressurizing the RCS when cold
- maintains the water level in the pressurizer when the RCS is hot
- reduces the concentration of corrosion and fission products in the reactor coolant
- adjusts the boric acid concentration of the reactor coolant for chemical shim control
- provides high pressure seal water for the reactor coolant pump (RCP) seals.

Though the CVCS system at each PWR performs basically the same functions, plant to plant and vendor design differences do exist. Some plants use regenerative heat exchangers to cool both the letdown flow and the charging flow. Charging flow is provided by either positive displacement or centrifugal pumps, or a combination of each.

A typical CVCS system is composed of the following subsystems:

- letdown cooling system
- demineralizers
- boron thermal regeneration system
- volume control storage tank
- boric acid supply
- charging pumps
- RCP seal water injection.

Most of the CVCS components are located outside the containment, so aging degradations which result in external leakage of the reactor coolant may also represent a small LOCA. Several CVCS components are also used in the HPIS. The effects of aging of the HPIS were analyzed by Meyer (1989). The failures for the components used by each system can affect both. For example, charging pump failures would have affected both the ability to provide charging and HPI flow. The effect of aging on the CCWS has been studied by Higgins et al. (1988) and Lofaro et al. (1992).

17.1 Aging Concerns and Mechanisms

The CVCS components (pumps, valves, piping, heat exchangers, etc.) are subject to deposition, corrosion, and biofouling, the extent of which depends on the system type.

Grove and Travis (1995) have performed the only study on aging of the CVCS. Based on this analysis, it was determined that the degradation of the positive displacement pumps and isolation and control valves accounted for the majority of the system failures. Pump packing degradation resulting in reactor coolant leakage, continues to be an industry wide problem with positive displacement pumps.

Table **17.1** provides the aging degradation concerns and mechanisms for the CVCS. In this table, the pumps represent the charging pumps, centrifugal or positive displacement type. The valves could be motor operated, air operated, or check valves. The heat exchangers could be regenerative or non-regenerative.

Table 17.1 Aging concerns and mechanisms for chemical and volume control systems

Component	Material	Aging Concerns	Aging Mechanisms	References
Pump Impeller or Piston	Stainless Steel	Distortion, Binding	Erosion, Corrosion, Wear, Fatigue	Grove and Travis 1995
Pump Casing	Cast Stainless Steel	Wall Thinning, Cracking, Leakage	Corrosion, Erosion, Wear, Embrittlement	
Pump Bearings	Cast Iron	Leakage	Wear, Abrasion	
Pump Seals and Gaskets	Rubber, Elastomer	Leakage	Creep, Hardening	
Valve Body	Stainless Steel	Wall Thinning	Corrosion, Erosion	
Valve Seat	Elastomer	Leakage	Wear	
Valve Internals	Stainless Steel	Distortion	Erosion, Corrosion	
Valve Seals, Gaskets	PTFE, Graphite	Leakage	Wear	
Heat Exchanger Tubes	Stainless Steel	Fouling, Blockage, Leakage	Corrosion, Debris, Erosion, Wear	
Heat Exchanger Shell	Stainless Steel, Carbon Steel	Thinning	Corrosion, Erosion	

17.2 Managing Aging Degradation

Grove and Travis (1995) have concluded that with the exceptions of high pressure injection, emergency **boration,** and containment isolation, all of the CVCS functions are non-safety related. Sufficient redundancy is provided for key system components such that failure does not result in the loss of function. The majority of the system inspections and tests are performed in accordance with **ASME** Section XI **(ASME 1992),** Appendix J, **and** plant technical specifications. In response to frequent reactor coolant leakage occurrences due to packing failures, many plants have increased visual inspection of the pumps from quarterly to weekly. Furthermore Grove and Travis **(1995)** recommend a detailed review of the industry experience with respect to pump **packing** degradation, emphasizing **packing** material design, inspection and surveillance frequency.

Table **17.2** indicates the management options to mitigate aging.

Table 17.2 Managing aging in chemical and volume control systems

Component	Material	Aging Mechanisms	Management Options	References
Pump Impeller, Piston	Stainless Steel	Erosion, Corrosion, Wear, Fatigue	Visual Inspection, Pressure, Vibration Tests	Grove and Travis 1995
Pump Casing	Cast Stainless Steel	Corrosion, Erosion, Wear, Embrittlement	Visual Inspection, Temperature Test	
Pump Bearings	Cast Iron	Wear, Abrasion	Lube Oil Monitoring	
Pump Seals and Gaskets	Rubber, Elastomer	Creep, Hardening	Visual Inspection	
Valve Body	Stainless Steel	Corrosion, Erosion	Visual Inspection	
Valve Seat	Elastomer	Wear	Visual Inspection, Position Test	
Valve Internals	Stainless Steel	Erosion, Corrosion	Visual Inspection, Flow Test	
Valve Seals, Gaskets	PTFE, Graphite	Wear	Visual Inspection,	
Heat Exchanger Tubes	Stainless Steel	Corrosion, Debris, Erosion, Wear	Hydrostatic Testing	
Heat Exchanger Shell	Stainless Steel, Carbon Steel	Corrosion, Erosion	Internal Visual Inspection	

17.3 References

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18 Heat Exchangers and Chillers

Heat exchangers and chillers constitute a portion of the heat transfer equipment within a nuclear reactor plant. The heat exchangers included in this section are of the non-power-cycle type used in safety related systems or to provide normal operating capability in nuclear power plants. The heat exchangers that are associated with the power conversion systems, such as steam generators, main condensers, feedwater heaters, and turbine plant equipment coolers are not included as a part of this study. The Isolation Condenser System (ICS), as a part of the ECCS in some BWRs, has also been addressed in this study. The chillers used in essential safety heating, ventilating, and air-conditioning (HVAC) plants of NPPs have been studied. The essential chillers provide chilled water to cool the control room and other rooms containing safety related equipment and personnel at nuclear power plants. Most of the nuclear power plants have at least two essential chillers that serve safety systems in the control rooms and various equipment rooms; one chiller serves as a backup and provides the safety redundancy required.

18.1 Heat Exchangers

Numerous heat exchangers are used in PWRs and BWRs, usually serving as interfaces between plant systems while transferring heat toward the normal or ultimate heat sink to establish or maintain desired process or equipment temperatures. With the exception of containment or room coolers, which are finned coil types with air on the outside of the tubes, the predominant heat exchanger type is the shell and tube. Such a design consists of two intertwined pressure vessels. The inlet header, outlet header, inside of the tubes and the inlet/outlet nozzles define the domain of the pressure vessel commonly referred to as the "tubeside" chamber (Figure 18.1; Singh and Soler 1984). The remaining space in the heat exchanger between the shell and the tubes is the other pressure vessel, known as the "shellside" chamber. Two fluids at different temperatures enter the two pressure chambers, exchange heat across the tube walls through a combined conduction-convection mechanism, and then exit through the outlet nozzles. Shell and tube heat exchangers are used for all water to water heat transfer applications.

Isolation condensers are horizontal shell and tube heat exchangers in which steam is condensed in the tubeside chamber. The heat of the steam is removed by the demineralized water on the shellside which boils and is vented to the atmosphere. The ICS is part of the ECCS of some BWRs in the United States. The ICS is designed to provide emergency cooling to the reactor when the reactor vessel becomes isolated from the turbine and the main condenser by closure of the main steam isolation valves. The system removes residual and decay heat from the reactor, and depressurizes the reactor vessel in the event the main condenser is not available as a heat sink. The flow path of a typical ICS loop is shown in Figure 18.2 (Orton 1995). Upon manual or automatic initiation of the ICS, steam flows from the reactor vessel to the isolation condenser, is condensed in the tube bundles, and returns to the reactor via recirculation pumps.

Finned coil type of heat exchangers are used for containment or room cooling. In these heat exchangers, the water flows through the tubes, whereas the air is forced across the tube bundle. The flow of air is by forced convection using fans. A typical pump room cooler is shown in Figure 18.3 (Blahnik and Goodman 1986). Warm air flows at the bottom left and passes through the cooling coils, where it is cooled. It continues through a plenum zone into a fan. The electric motor driven fan moves the cool air into a short duct and returns it to the room through the outlet.

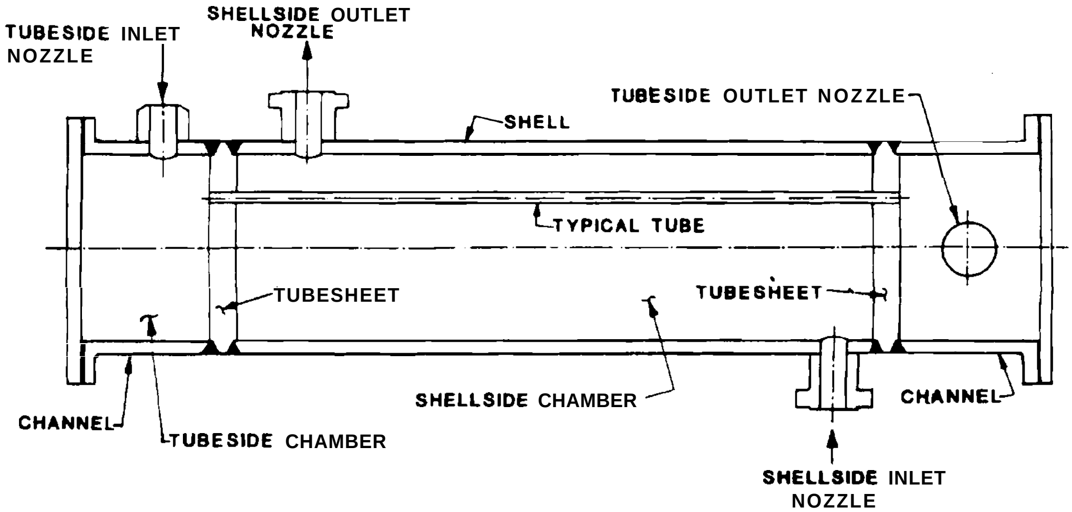

Figure 18.1 Typical heat exchanger schematic

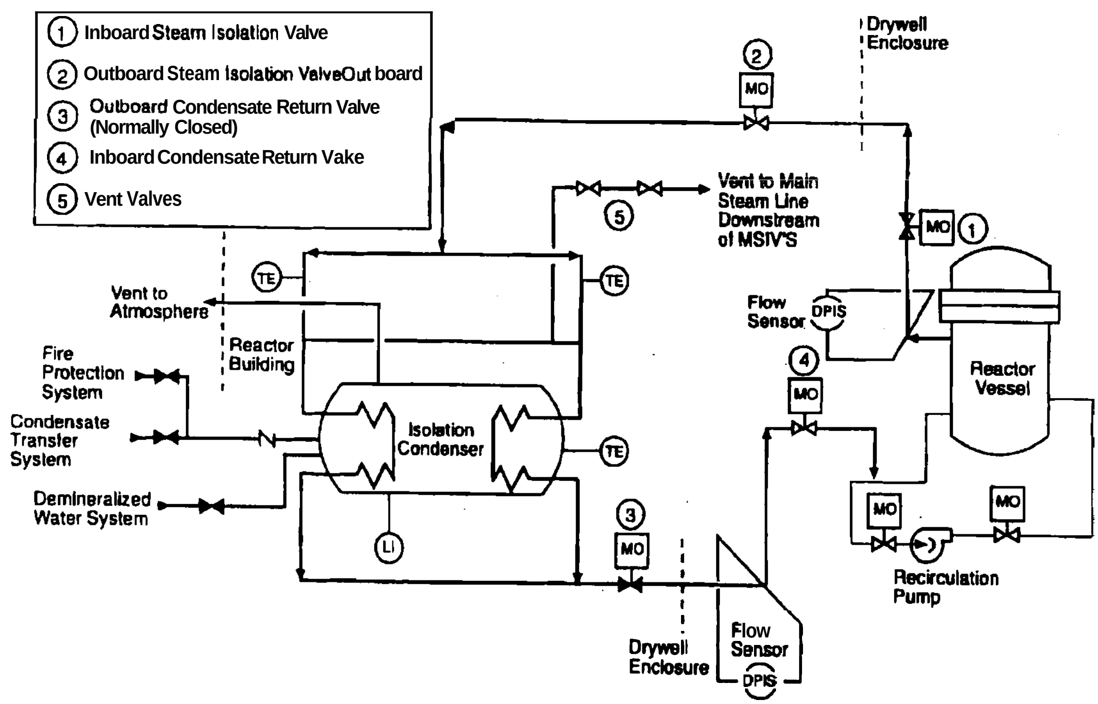

Figure 18.2 Isolation condenser (BWR)

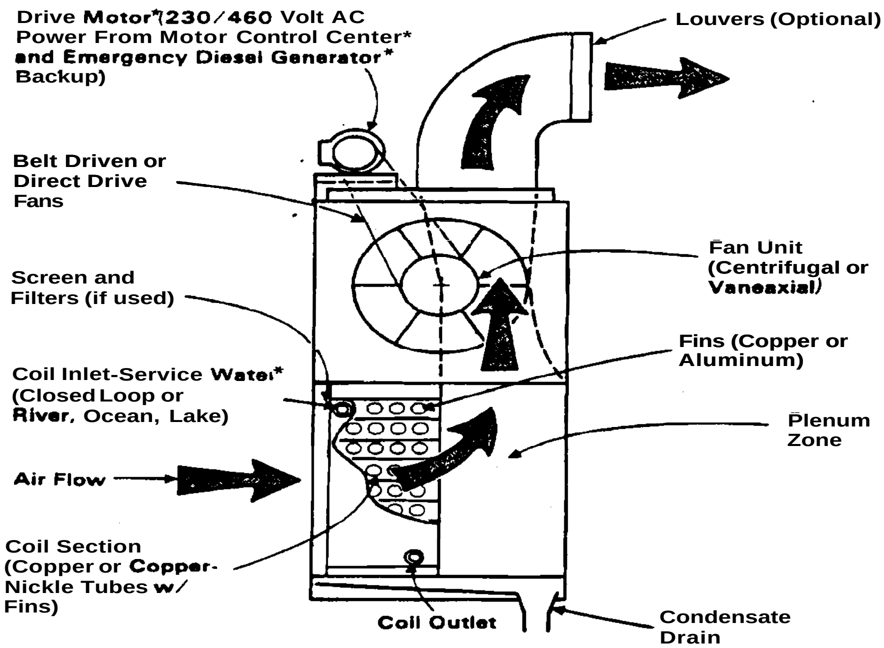

Figure 18.3 **Pump room cooler**

18.1.1 Aging Concerns and Mechanisms

Booker et al. (1994) have investigated aging mechanisms acting on heat exchangers of both the shell-and-tube and the finned coil types. Their evaluations within the aging management guidelines (AMGs) identify the heat exchanger tubes/coils, tubesheets, shell/nozzles/internals, waterbox/channel head/divider plate, and support assembly bolts as components with significant aging effects. Moyers (1992) has proposed 1) flow blockage, 2) external leakage, 3) interfluid leakage, and 4) reduced heat transfer capability (due to fouling of the heat transfer surface) as significant degradation effects caused by aging. The aging concerns and mechanisms associated with heat exchangers are highlighted in Table 18.1.

Table 18.1 Aging degradation concerns and mechanisms for heat exchangers

Components	Materials	Aging Concerns	Aging Mechanisms	References
Tubes/Coils	Stainless Steel, Brass, Cu-Ni, Copper, Titanium	Leakage, Blockage	Fatigue, Corrosion, Wear, Fouling, Vibration	Booker et al. 1994; Moyers 1992
Tubesheets	Carbon Steel, Stainless Steel	Leakage, Blockage	Fatigue, Corrosion, Wear	
Shell/Nozzles/Internals	Carbon Steel, Stainless Steel	Leakage, Blockage	Fatigue, Corrosion, Erosion, Fouling	
Waterbox/Channel Head/ Divider Plate	Carbon Steel, Stainless Steel	Leakage, Blockage	Fatigue, Corrosion, Erosion, Fouling	
Support Bolts	Forged Stainless Steel, Forged Carbon Steel	Loss of Preload	Corrosion, Stress Relaxation	

18.1.2 Managing Aging Degradation

Booker et al. (1994) have provided a comprehensive discussion on effective management of aging mechanisms. The various aging mechanisms identified in the previous section will manifest and progress at different rates and are affected by many variables such as material composition, operating service conditions, environmental parameters, geometric configuration, etc.

As such, program implementing procedures must be performed at a frequency commensurate with the rate of aging to ensure detection and mitigation of degradation. Moyers (1992) has addressed degradation monitoring of the heat exchanger failures represented by 1) flow blockage. 2) external leakage, 3) interfluid leakage, and 4) fouling of heat exchange surface. It is concluded that presently used methods for detection of flow blockage and leakage are adequate. The various methods for managing aging degradation are summarized in Table 18.2.

Table 18.2 Managing aging degradation for heat exchangers

Components	Materials	Aging Mechanisms	Management Options	References
Tubes/Coils	Stainless Steel, Brass, Cu-Ni, Copper, Titanium	Fatigue, Corrosion, Wear, Fouling, Vibration	Eddy current, acoustic emission, leak testing, flow measurement, vibration monitoring	Moyers 1992; Booker et al. 1994
Tubesheets	Carbon Steel, Stainless Steel	Fatigue. Corrosion, Wear	Visual inspection. leak testing	Booker et al. 1994
Shell/Nozzles/ Internals	Carbon Steel, Stainless Steel	Fatigue, Corrosion, Erosion, Fouling	Acoustic emission, radiographic/ultrasonic inspection, leak testing, flow measurement	Moyers 1992
Waterbox/ Channel Head/ Divider Plate	Carbon Steel, Stainless Steel	Fatigue, Corrosion, Erosion, Fouling	Visual inspection	Booker et al. 1994
Support Bolts	Forged Stainless Steel, Forged Carbon Steel	Corrosion, Stress Relaxation	Volumetric Examination, torque monitoring	Moyers 1992

18.2 Chillers

The essential chillers provide chilled water to cool the control room and other rooms containing safety-related equipment and personnel at NPPs. The essential chilled water systems must be available at all times, have redundancy, and function during and after a safe shutdown earthquake (SSE), LOCA, or loss of offsite power (LOP).

About 90% of the chillers found in NPP Final Safety Analysis Reports (FSARs) were centrifugal chillers. Others were screw, rotary, and reciprocating chillers which were used primarily in older and smaller plants (Blahnik and Camp 1995). A cross-sectional schematic view of a centrifugal chiller is shown in Figure 18.4. It shows the major components and the direction of flow of condenser and cooler water and the refrigerant in various phases. The refrigerant used as heat transfer medium is usually CFC R-11 or CFC R-12. The major components of the chiller are a cooler, a condenser, a motor driven centrifugal compressor, and an economizer. The cooler is a heat exchanger vessel in which the flashing refrigerant picks up the heat from, and therefore chills, the water flowing through its tubes. The condenser is a heat exchanger vessel in which the heat is removed from compressed refrigerant and is carried out to the system. The motor-compressor maintains the necessary pressure difference in the system and moves the heat-carrying refrigerant from cooler to the condenser. The economizer is a vessel at intermediate pressure between the cooler and the condenser which returns "flash gas" to the compressor for greater cycle efficiency (Blahnik and Klein 1993).

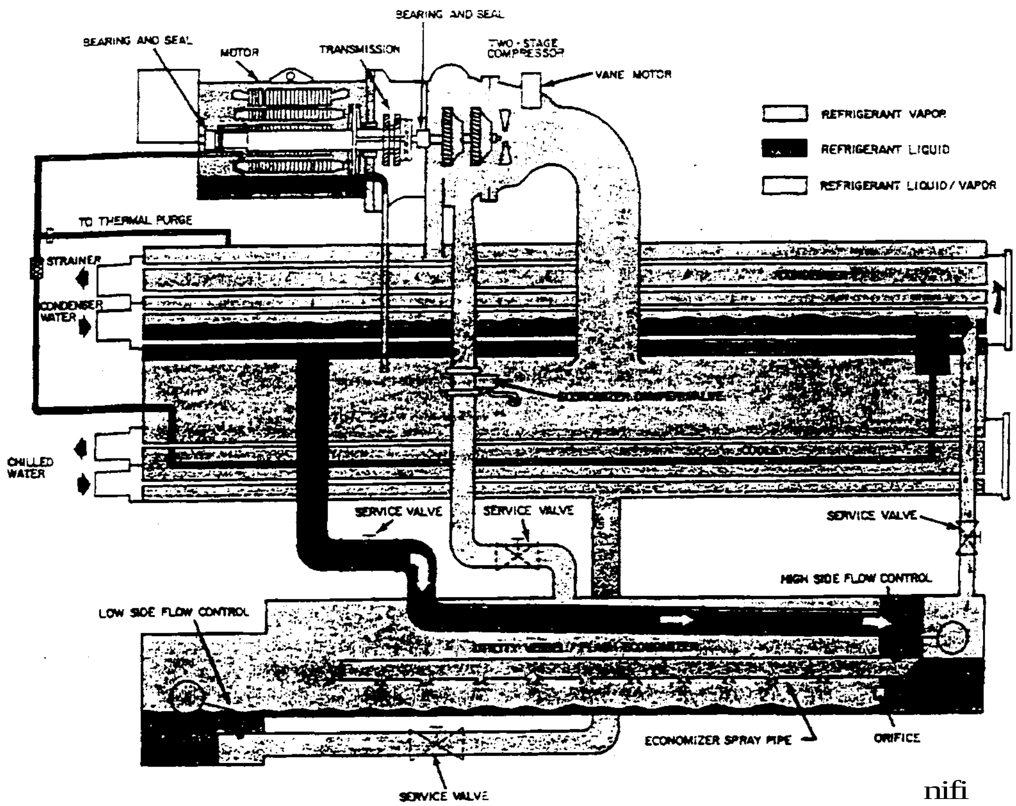

Figure 18.4 Centrifugal chiller schematic

18.2.1 Aging Degradation Concerns and Mechanisms

Blahnik and Camp (1995) found most of the failures in the cooler/condenser heat exchanger area and nearly all of the failures to be condenser related. Approximately **38%** of the failures were attributed primarily to aging, **55%** were partially aging related. In over 50% of the age related failures, corrosion was found to be involved. One of the sig cant forms of corrosion is from the acid attack, which is described as follows. Excessive moisture in the refrigerant leads to the formation of hydrochloric acid and hydrofluoric acid, as the free water reacts with the refrigerant. The acid attacks the crevices between the tube and the tube support plates. These crevices widen and the tubes ultimately fail as the tubes vibrate, especially due to the boiling refrigerant in the cooler. The acid reacts with the lubricating oil which degrades the bearings. It corrodes the compressor inlet guide vane assembly causing it to bind. The acid attack leads to shell scaling which clogs the space between the tube fins and the tubes and produces copper chloride deposits on the upper tubes. Other factors that cause aging related degradation are SCC, fatigue, erosion and wear. Excessive start/stop cycling and underloading of chillers can promote rapid aging. Aging is also accelerated by corrosion and fouling of the cooler and condenser tubes. A summary of aging degradation concerns and mechanisms for chillers is provided in Table **18.3.**

18.2.2 Managing Aging Degradation

The chiller aging study by Blahnik and Klein **(1993)** indicated that the primary cause of chiller failures and accelerated aging was a lack of proper service life monitoring. Accordingly, the main objective of the study by Blahnik and Camp **(1995)** was to seek information in this area. Essential condition monitoring methods for chillers include operational data recording, monitoring and trending analysis; refrigerant and oil leak detection; refrigerant and oil analysis; condenser and cooler tube eddy current testing; and infrared thermal analysis. Computerized monitoring is the ultimate method that will continually monitor the chillers and their interfacing systems.

Table 18.3 Aging degradation concerns and mechanisms for chillers

Components	Materials	Aging Concerns	Aging Mechanisms	References
Cooler and Condenser Tubes	Copper, Cu90/ Ni10, Titanium	Leakage, Flow Blockage	ID corrosion, ID pitting, OD corrosion, OD pining from acid attack, stress corrosion cracking, fouling, erosion, fatigue, vibration, wear	Blahnik and Camp 1995
Cooler and Condenser Shell, Internals	Carbon Steel	Shell Scaling. Clogging Between Tubes	Acid attack, vibration, fretting corrosion, wear	
Compressor Bearings	Bronze, Aluminum Alloy	Bearing Failure, Leakage	Thermal distortion, wear, acid attack with lubricant	
Compressor Guide Vanes	Bronze, Aluminum	Binding	Corrosion	
Compressor Impellers	Cast Aluminum	Leakage	Fatigue, vibration, wear	

To minimize failures, the operators of the chillers need to carefully follow stringent procedures and monitoring schedules. Equipment performance must be recorded and trended on a daily basis. Since a small amount of contamination or a damaged or misaligned part can cause major problems, it is crucial that the equipment internals be kept very clean and the leakage of water, air and other contaminants into the sealed refrigerant containment system be prevented. Furthermore, the chillers need to be operated as close to the 100% capacity as practical to minimize aging degradation. Management options to mitigate the aging degradation identified earlier have been outlined in Table 18.4.

Table 18.4 Managing aging degradation for chillers

Component	Materials	Aging Mechanisms	Management Options	References
Cooler and Condenser Tubes	Copper, Cu90/ Ni10, Titanium	ID Corrosion, ID pitting, OD corrosion, OD pitting from acid attack, stress corrosion cracking, fouling, erosion, fatigue, vibration, wear	Eddy current test (3-5yrs); replace or plug tubes if necessary; eliminate scaling by mechanical or chemical method; perform vibration analysis	Blahnik and Camp 1995, Appendix D
Cooler and Condenser Shell, Internals	Carbon Steel	Acid Attack, Vibration, Fretting Corrosion, Wear	Control impurities in refrigerant; ensure proper refrigerant charge and temperature	
Compressor Bearings	Bronze, Aluminum Alloy	Thermal Distortion, Wear, Acid Attack with Lubricant	Sample and analyze lubricant	Blahnik and Camp 1995, Appendix C
Compressor Guide Vanes	Bronze, Aluminum	Corrosion	Control impurities in refrigerant	
Compressor Impellers	Cast Aluminum	Fatigue, Vibration, Wear	Monitor vibrations	

18.3 References

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19 Steam Turbine Drives for Safety Related Standby Pumps Compressed Air Systems

Steam turbine drives are used within the AFWSs of PWRs, and within the HPCI and RCIC systems of BWRs. Turbine drives are redundant components to electric pump motors within those systems. The turbine-driven pump (TDP) would be relied upon to provide coolant flow in the event of a loss of electrical power to the motordriven pumps (MDP) during activation of the AFW, HPCI or RCIC systems.

The turbine drives are composed of the turbine, turbine overspeed trip system, governor and governor valve, steam admission and triplthrottle valves. Depending on the configuration of the system, either the steam admission or the triplthrottle valve is opened in response to a turbine-start signal. As the turbine spins up to the desired rotational velocity, the governor throttles the governor valve to maintain the turbine speed at the desired setpoint. A governor may be a mechanical type or an electronic type; in either case the governor controls a hydraulic actuator to control the governor valve. In the event of turbine overspeed, a spring-loaded trip pin extends from turbine shaft due to the influence of centrifugal force. If the rotational speed of the shaft is in excess of the trip setpoint, the trip pin will strike a tappet within the trip actuation system, resulting in the closure of the triplthrottle valve and the consequent isolation of the turbine from the steam supply.

Most of the safety-related AFW, HPCI, or RCIC standby TDPs in use today have been manufactured by the Terry Corporation (currently DRESSER-RAND, Terry-Turbodyne) and employ governors manufactured by the Woodward Corporation. These systems have a long history of reliable service in the petrochemical and chemical industries as well as fossil-fueled power plants. However, in these applications the turbine drives are started slowly and operated continuously. This is not the case in AFW, HPCI and RCIC systems, in which the TDPs are required to go from cold-standby to full capacity in 60 to 120 seconds, and to operated over a wide range of inlet steam pressures. These requirements are a considerable challenge to the capabilities of TDPs, and the testing required to verify that these requirements are fulfilled has proven to have a considerable detrimental impact on TDP reliability. Operating experience has shown that most instances of turbine drive failures have not involved the turbines themselves, but originate instead with the governor and overspeed trip systems.

19.1 Aging Concerns and Mechanisms

The major aging concerns for turbine-driven AFW, HPCI, and RCIC pumps are identified in Cox (1991) and Boardman (1994), and are listed in Table 19.1. About 72% of the problems with TDPs are the result of failures of the speed control components (Cox 1991). These components are susceptible to the deleterious effects of frequent "quick-start" testing from a cold-standby condition. Wear to the turbine bearings is increased at start time due to inadequate lubrication; as a result, the lubricating oil is contaminated with metal particulates. Leaks in the steam isolation valves also introduce water contamination into the lubrication oil, leading to inadequate oil viscosity as well as corrosion due to increased humidity and temperature within the system. Because the governor often uses the turbine lubrication oil as its control oil supply, control valves and orifices within the governor may become clogged with particulate matter, resulting in sluggish governor operation. Often the response of the governor becomes so sluggish that it is unable to prevent a turbine overspeed during a quick start; the result is that high demand failure probabilities, around 6.5E-2, are often observed for TDPs.

Table 19.1 Understanding aging of the auxiliary feedwater system

Component	Material	Aging Concerns	Aging Mechanisms	References
Valve Seat	Elastomer	Leakage	Wear	Casada 1990
Valve Lntemals	Stainless Steel	Leakage	Wear	
Valve Packing	PFTE, Graphite	Leakage	Wear	
Governor (Electronic)		Calibration Drift, Sluggish Response	Corrosion, Debris Buildup	
Governor (Mechanical)		Loss of Material, Sluggish Response	Corrosion, Debris Buildup	Cox 1991, pp. 6-7 Boardman 1994, p. 12
Trip Tappet Head (older ball tappets only)	Urethane	Swelling	Chemical Reaction with Lubricating Oil	Cox 1991, pp. 6-7
Trip Tappet Stem	Stainless or Carbon Steel	Binding	Deformation	
Valve Stem	Carbon Steel, Stainless Steel	Binding	Corrosion, Scale Buildup	
Emergency Trip Spring	Spring Steel	Elongation/Loss of Tension	Creep	Information Notice 90-76
Turbine Bearings	Tin-Based Babbitt	Spalling, Loss of Material	Wear	Information Notice 81-24
Governor Linkage	Steel	Binding	Dirt Accumulation	Boardman 1994

19.2 Managing Aging Degradation

The aging degradation and concerns for specific Turbine Drive components were summarized in the previous section. In this section, the options for better managing the aging for this system are discussed. Options for detecting and/or mitigating aging-related degradation are summarized in Table 19.2.

A large fraction of Steam Turbine Drive failures have been found as a result of testing (52.8% between 1984 and 1990), followed by demand failures (21.5% during the same period). Due to the small amount of time that these components are actually operated on demand, the number of demand failures observed is significant. There is strong evidence that the number of demand failures per year has undergone a dramatic decrease in the period from 1985 to 1990; this is a consequence of improved and more frequent inspection and maintenance of these components, which results in a greater number of failures being detected as a result of testing.

There has been a great amount of variability within the industry in terms of the content of the turbine drive inspection procedures. PWR plants typically perform monthly pump operability tests, while BWR plants typically perform such tests on a quarterly cycle. The types of tests vary widely, with some plants performing hot quick-start tests (in which the drive is restarted after a slow-start test from cold standby), others perform cold quick-starts, and still others perform slow starts after the turbine speed has initially been brought to the slow speed stop. However, according to General Electric Service Information Letters from as early as 1994, only cold quick-start tests provide a valid indication of turbine operability for standby turbine driven pumps.

Table 19.2 Managing aging degradation of turbine drives for safety-related pumps

Component	Material	**Aging Mechanisms**	**Management** Options	**References**
Valve Seat	Elastomer	Wear	Wear Tracking	**Kueck** 1993
Valve lnternals	Stainless Steel	Wear	Wear Tracking	
Valve Packing	**PFTE**, Graphite	Wear	Wear Tracking	
Governor (Electronic)		Corrosion, Debris Buildup	Established Testing and Maintenance Procedures	
Governor (mechanical)		Corrosion, Debris Buildup	Established Testing and Monitoring Procedures	Cox 1991, pp. 6-7 NUREG-1275 **v.10**, p. 12
Trip Tappet Head (older ball tappets only)	Urethane	Chemical Reaction with Lubricating Oil	Replace Older Components with Newer Design	Cox 1991, pp. 6-7
Trip Tappet Stem	Stainless or Carbon Steel	Deformation	Established Testing and Maintenance Procedures	
Valve Stem	**Carbon Steel**, Stainless Steel	Corrosion, Scale Buildup	Established Testing and Maintenance Procedures	
Emergency Trip Spring	Spring Steel	Creep	Established Testing and Calibration Procedures	Information Notice 90-76
Turbine Bearings	Tin-Based Babbitt	Wear	Lubrication Oil Quality Monitoring end Maintenance, Established Inspection Procedures	**Information** Notice 81-24
Governor Linkage	Steel	Dirt accumulation	Established inspection and maintenance procedures	**NUREG** 1275, v.10

Most turbine failures are the result of speed control failures, and the governor is particularly susceptible to the detrimental effects of testing (which induces heat and humidity into the system) and improper maintenance. This is due to the small size of control oil flow orifices and valves within the governor system. The governor control system shares its oil supply with the turbine lubrication system, and contamination of the latter can lead to clogging of the small orifices as well as higher than normal oil viscosities. The result is sluggish response of the governor, which can hinder the governor's ability to prevent a turbine overspeed and consequent trip.

19.3 References

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20 Bistables and Switches

Bistables and switches are vital in the instrumentation and control logic of an NPP. In essentially every system of the plant, they provide control logic inputs, trip signals, and annunciation, both for safety systems and balance of plant systems.

The use of bistables compared to switches in NPPs has tended to favor bistables over switches for the past 15 years. Bistables are now used in systems traditionally occupied by switches. The design of the instrumentation in all PWRs originally made use of transmitters and bistables and most older BWRs have upgraded from switches to transmitters and analog trip systems in their RPS and ECCS. Operating data have shown that problems with bistables and switches have forced plant power reductions and have caused loss or degradation of instrument channels on safety systems, reactor trips, and safety system actuations. In a study of failures and causes conducted between 1976 and 1981 it was found that of the reported events, 68% resulted from failure of switches, radiation monitors, transmitters, sensors, and bistables (Lee et al. 1993).

20.1 Aging Concerns and Mechanisms

Most aging in switches results from the mechanical aging of the parts, particularly the snapping elements required to close the switch. These elements require precise calibration making them exceptionally vulnerable to mechanical setpoint drift which normally occurs between adjustable parts. In addition to mechanical aging, electrical components, mostly older capacitors and potentiometers are subject to aging. For bistables, aging of electrical parts is the most prominent type of aging. Table 20.1 provides a summary of the types of aging that affects switches and bistables.

Table 20.1 Aging concerns and mechanisms in switches and bistables

Component	Parts of Concern	Aging Concerns	Aging Mechanisms	Reference
Pressure Switches	Diaphragm, Bourdon Tube, and Bellows Sensing Element	Failure to Operate or Lack of Calibration	Corrosion, Vibration, Shock, Radiation, and Temperature	Lee et al. 1993
	Snapping Element	Failure or Intermittent Actuation	Corrosion, Mechanical Drift, Heat, and Dirt	
Level Switches	Internal Components and Sensing Elements	Loss of Function and Spurious Signal	Wear, Fatigue, and Electrical Switching Element Problems	
Mechanical Temperature Switches	Internal Components	Loss of Calibration Due to Mechanical Setpoint Drift	Wear, Vibration, and Fatigue	
Electrical Temperature Switches	Electronic Components	Loss of Function	Degradation of Electronic Components	
Rotary Switches	Contacts, Assembly, and Spring	Loss of Function	Stress, Heat, Corrosion, Arcing, Radiation, Chemicals	Roberts et al. 1988, p. 33
Bistables	Capacitors, Potentiometers, Integrated Circuits, and Transistors	Loss of Calibration, Spurious Alarms, Loss of Function	Insulation Breakdown, Burnout of Parts	Lee et al. 1993

Mechanical aging of parts due to drift, corrosion, shock, radiation, and heat often cause a loss of calibration and failed or intermittent signals among pressure switches. Level switches are affected in this way as well, in addition to being prone to clogged and leaking sensing lines due to accumulation of residue, or crimped lines. Rotary switches, which are composed of many moving parts, are affected by stress, chemicals, and arcing in addition to the above listed mechanisms. Mechanical temperature switches are affected in the same way as pressure and rotary switches, but failure in electrical temperature switches usually results from degradation of electronic components. Bistables are also prone to the aging of electronic components. Older bistables and electronic temperature switches are often prone to burnout of capacitors, potentiometers, integrated circuits, and transistors. This can cause loss of calibration or function or spurious alarms. Although newer bistables contain better parts such as tantalum and aluminum electrolytic capacitors, component burnout is still possible.

20.2 Managing Aging Degradation

The primary means of inspecting and monitoring the performance of bistables and switches is the Technical Specifications surveillance testing of the instrumentation and controls associated with nuclear safety systems. Table 20.2 lists aging concerns and their management. The management of mechanical switches involves mostly routine checking such as channel, calibration, and function checks (Lee et al. 1993). In addition to these checks, rotary switches should be checked with torque measurements and contact resistance measurements (Roberts et al. 1988, p.45). Although switches are inexpensive and reliable, many NPPs have found that in safety applications switches require excessive monitoring and maintenance, and have decided to upgrade to transmitters and bistables which have proven to be more accurate and reliable than switches.

For electric bistables, in addition to running Technical Specification surveillance testing, it is also recommended to follow the prescribed procedures whenever the failures are detected. Usually, corrective actions initially involve attempts to recalibrate the instrument, and then replace the circuit card if the recalibration is unsuccessful. The plant may then attempt to repair the card in its shop, or return it to the manufacturer. Preventive maintenance for the bistable racks, circuit cards, fans, and filters are incorporated into either the applicable surveillance testing procedures or the plant's preventative maintenance program.

Table 20.2 Managing aging in switches and bistables

Component	Aging Mechanisms	Management Options	References
Pressure Switches	Corrosion, Vibration, Shock, Radiation, heat, dirt, and mechanical drift	Technical Specification surveillance testing, channel, calibration and, and function checks. Upgrade switches in safety systems to transmitters and electric bistables	Lee et al. 1993
Level Switches	Wear, Fatigue. and Electrical Switching Element Problem		
Mechanical Temperature Switches	Wear, Fatigue, and Vibration		
Electrical Temperature Switches	Degradation of Electrical Components		
Rotary Switches	Stress, Heat, Corrosion, Arcing, Radiation, and Chemicals	Visual Inspections, Operational Checks, Torque Measurements, and contact resistance measurements	Roberts et al. 1988, p. 45
Bistables	Insulation Breakdown, and Burnout of Parts	Technical Specification Surveillance Testing	Lee et al. 1993

20.3 References

Lee, B. S., M. Villaran, and M. Subudhi. 1993. *Aging Assessment of Bistables and Switches in Nuclear Power Plants*. NUREG/CR-5844, TI93 007057, Brookhaven National Laboratory, Upton, New York.

Roberts, G. C, V. P. Bacanskas, and G. J. Toman. 1988. *Aging and Service Wear of Multistage Switches Used in Safety Systems of Nuclear Power Plants*. NUREG/CR-4992, ORNL/Sub/83-28915/5&V1, Oak Ridge National Laboratory, Oak Ridge, Tennessee.

21 Motors and Motor Control Centers

This section covers electric motors and associated motor control centers. Nuclear power plants contain approximately 1100 motors (Subudhi et al. 1987) some of which are needed for safe operation of the plant. Management of the aging impacts to these motors is necessary for continued long term operation of the plants.

21.1 Motor Mechanisms

NPPs use electric motors as vital system components for both the performance of normal system operation and as safeguards to limit the possibility of radioactive release in the event of abnormal events. The motors used range in power output from less than 3/4 hp to greater than 250 hp and are used in MOVs, pumps, fans, and other miscellaneous applications.

21.1.1 Aging Concerns and Mechanisms

The two most common causes for the failure of motors in NPPs is excessive heat and vibration. In addition to these stressors, motors also are affected by misalignment, material degradation, and lubricant degradation. Table 21.1 presents aging concerns and mechanisms as they affect different components of a motor.

Table 21.1 **Aging concerns and mechanisms in motors**

Component	Material of Concern	Aging Concern	Aging Mechanisms	References
Stator	Insulating Materials	Ground Insulation Burnout	Overheating, Vibration, and Materials Degradation	Subudhi et al. 1985, pp. S-2 through S-3
Bearings	Grease, Lube Oil, Steel, Brass, Bronze	Bearing Failure	Vibration and Deterioration of Lubrication Due to Heat or Foreign Materials	
Rotor	Insulating Materials	Failure or Excessive Friction	Heat, Vibration, and Misalignment	
Accessories	Seals, Gaskets, Mica, Plastic, Graphite, Cable, Insulating Material			

Excessive heat usually results from excessive current through the motor which results in self heating. The vibrational effects originate in abnormalities of internal parts. Most failures in motors result from failures of either the stator or bearings due to overheating and deterioration of lubricants. However, operational stresses such as frequent starts and stops of motors and backseating of valves can cause stress to the entire motor. The systems that are the most affected by motor failures are the RHR, SWS, and the HPCI systems (Subudhi et al. 1985, pp. S-2 through S-3).

21.1.2 Managing Aging Degradation

There are many ways to increase the life of the motors in a power plant and detect problems before failures occur. Periodic tests should be preformed at scheduled intervals on the motors to verify operability and to detect degradation. In addition to this, motors equipped with monitors should be monitored regularly according to the manufacturer's suggested time periods.

Table 21.2 gives a list of both dielectric and rotational integrity tests that should be run during monitoring of the motors. In addition to monitoring the condition of the motors, it is also recommended to inspect motors periodically for such things as contaminants, fractures, cracks, and vibration.

Table 21.2 Managing aging **in motors**

Component	Aging Mechanism	Management Options	Reference
Stator	Overheating, Vibration, and Materials Degradation	No load current measurement, winding resistance measurement, Dc/Ac leakage test, polarization index test, dissipation factor and capacitance test, impulse voltage test, winding temperature measurement, bearing vibration test, chemical analysis of lubricants, bearing temperature measurements	Subudhi et al. ***1987,*** pp. 2-5
Bearing	Vibration and Deterioration of Lubrication Due to Heat or Foreign Materials		
Rotor	Heat, Vibration, and Misalignment		
Accessories			

21.2 Motor Control Centers

Motor control centers (MCCs) control and protect the electrical motors throughout a reactor. The major components of an MCC are circuit breakers, relays, starters, transformers, terminal blocks and overloads. (See Section 15 for relays and circuit breakers used throughout the entire plant.) Motor control centers protect motors from power surges and starting motors after a shutdown. They also transform incoming current and voltage to levels compatible to the various motors they control.

21.2.1 Aging Concerns and Mechanisms

Common causes of MCC failure include excessive heat, stress, and cyclic fatigue. Other stressors are corrosion, residue buildup, and vibration. These stressors and their concerns are listed in Table 21.3. Systems most affected by MCC failures are those which are run at frequent, intermittent operation, because intermittence leads to the degradation of such parts as the starters, relays, and circuit breakers. A failure in an MCC often results in the loss of function in a downstream system. These failures have caused reactor scrams and an inability to restart the reactor, but these consequences can be mitigated by redundant design.

Table 21.3 Aging concerns and mechanisms in motor control centers

Component	Material of Concern	Aging Concern	Aging Mechanism	Reference
Circuit Breaker	Phenolic, Vulcanized Rubber	Failed or Sporadic Tripping	Cyclic Fatigue, Wear of Components, Residue Buildup	Shier and Subudhi ***1988,*** pp. 4-20 through 4-24
Relays	Neoprene	Incorrect Responses	Hent, Material Degradation, Stress, Misalignment	
Starter/Contactor	Lubricants, Adhesives, Silicone, Polyester	Failure to Open or Close	Stress, Heat, Surface Degradation, Foreign Materials	
Transformer Coils	Varnish, Polyester Film, Polyamide-imide Insulation	Short to Ground, Failed Circuit	Overheating, Material Degradation, Excessive Current	
Terminal Block	Phenolic	Poor Connection, Short to Ground	Stress, Humidity, Dust	
Overloads	Lubricants, Vulcanized Fiber	Improper Open Circuit	Cyclic Fatigue, Ambient Conditions	

21.2.2 Managing Aging Degradation

Table 21.4 provides a list of management options which mitigate the effects of aging. Inspection and monitoring of MCCs is highly recommended. The molded case CBs constitute the highest percentage of failures noted in MCC components. Many plants employ diagnostic techniques, but identification of degradation before failure is limited. Typically only 40% of CB failures are detected before failure occurs. In addition to this periodic monitoring, the plant should review their maintenance program if the MCC components are exposed to temperatures above 40 °C (104°F) for extended periods of time or if the components are frequently subjected to high cycles (Toman et al. 1994, pp.1-6 and 1-7).

Table 21.4 Managing aging in motor control centers

Component	Aging Mechanism	Management Options	Reference
Circuit Breaker	Cyclic Fatigue, Wear of Components, Residue Buildup	Visual Inspection, Operational Trip Test, Test for Freedom of Movement	Toman et al. 1994, pp. 1-3 through 1-5
Relays	Heat, Material Degradation, Stress, Misalignment	Visual Inspection of Coil, Inspection for Corrosion, Operational Tests	
Starter/Contactor	Stress, Heat, Surface Degradation, Foreign Materials	Visual Inspection of Coils, Visual Inspection for Dirt and Wear	
Transformer Coils	Overheating, Material Degradation, Excessive Current	Resistance Measurements, Inspection for Overheating and Cracking	
Terminal Blocks	Stress, Humidity, Dust	Visual Inspection for Overheating, Cracks and Improper Alignment	
Overloads	Cyclic Fatigue, Ambient Conditions	Visual Inspection for Overheating, Cracks, Dirt and Freedom of Movement	

21.3 References

Shier, W., and M. Subudhi. 1988. ***Operation Experience*** and ***Aging Assessment of Motor Control Centers.*** NUREG/CR-5053, BNF-NUREG-521188, Brookhaven National Laboratory, Upton, New York.

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Subudhi, M., W. Gunther, and J. Taylor. 1987. ***Improving Motor Reliability in Nuclear Power Plants, Volume I: Performance Evaluation and Maintenance Practices.*** NUREG/CR-4939, BNWNUREG-52031, Brookhaven National Laboratory, Upton, New York.

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