
Aging Study of Boiling Water Reactor High Pressure Injection Systems

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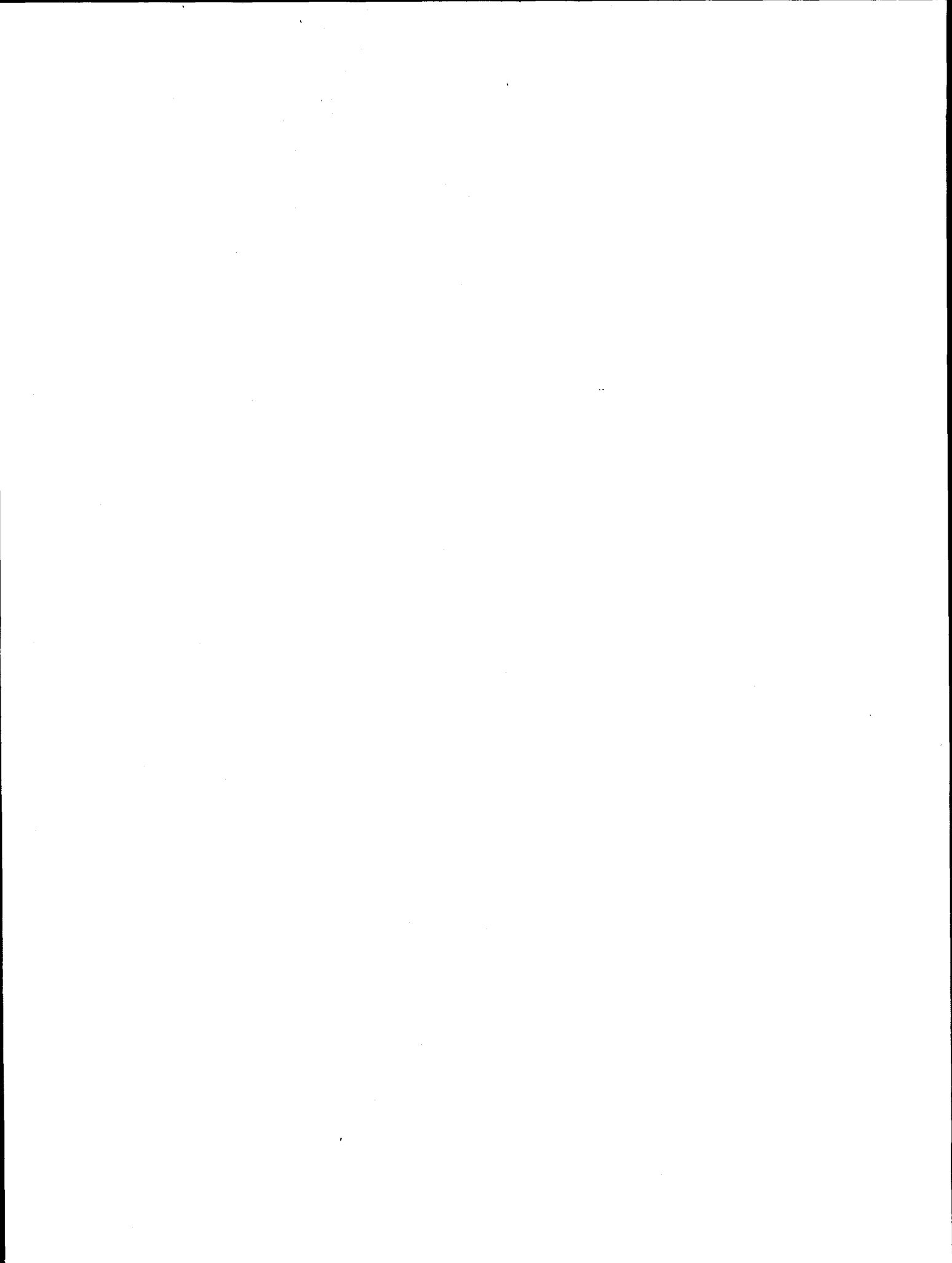
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ABSTRACT

The purpose of high pressure injection systems is to maintain an adequate coolant level in reactor pressure vessels, so that the fuel cladding temperature does not exceed 1,200°C (2,200°F), and to permit plant shutdown during a variety of design basis loss-of-coolant accidents. This report presents the results of a study on aging performed for high pressure injection systems of boiling water reactor plants in the United States. The purpose of the study was to identify and evaluate the effects of aging and the effectiveness of testing and maintenance in detecting and mitigating aging degradation. Guidelines from the United States Nuclear Regulatory Commission's Nuclear Plant Aging Research Program were used in performing the aging study. Review and analysis of the failures reported in databases such as Nuclear Power Experience, Licensee Event Reports, and the Nuclear Plant Reliability Data System, along with plant-specific maintenance records databases, are included in this report to provide the information required to identify aging stressors, failure modes, and failure causes. Several probabilistic risk assessments were reviewed to identify risk-significant components in high pressure injection systems. Testing, maintenance, specific safety issues, and codes and standards are also discussed.



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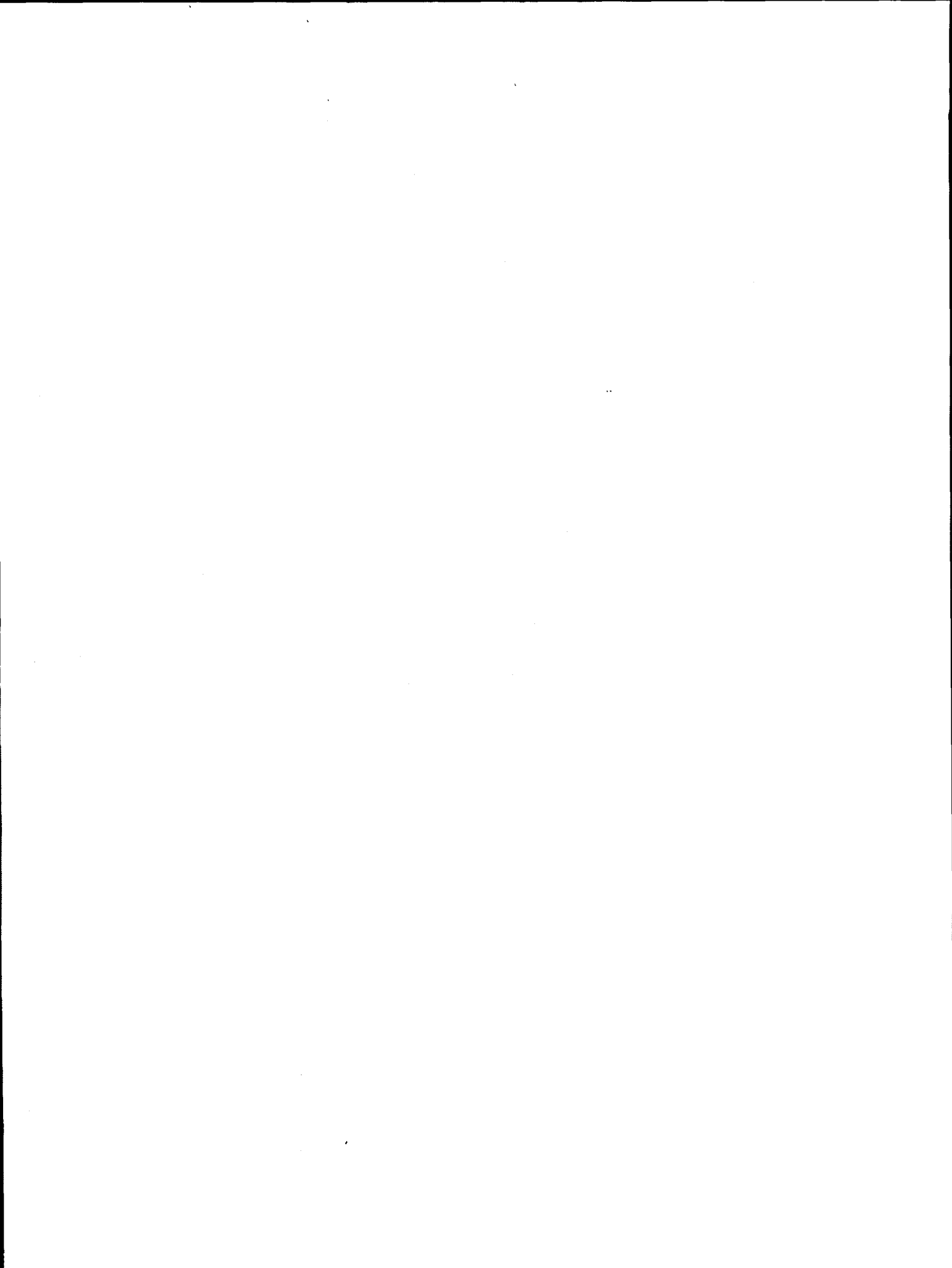
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EXECUTIVE SUMMARY

System and component failure experiences are evaluated through in-depth engineering studies sponsored by the United States Nuclear Regulatory Commission (NRC) to determine the significance of aging degradation on plant safety and system reliability. The subject selected for this study is boiling water reactor (BWR) high pressure injection (HPI) systems. The research followed NRC Nuclear Plant Aging Research (NPAR) Program guidelines described in NUREG-1144. NPAR projects employ available information from databases, vendors, open literature, utilities, and expert opinions to cover (a) an identification of failure modes, (b) an identification of failure causes related to aging and wear, (c) a review of inspection, surveillance, and monitoring methods, (d) a review of industry codes and standards, and (e) conclusions identifying potential follow-up work.

BWR plants have three variations of HPI systems: the feedwater coolant injection (FWCI) system, the high pressure coolant injection (HPCI) system, and the high pressure core spray (HPCS) system. The FWCI system is not very common, and of the three plants that employ this design, the Oyster Creek and Nine Mile Point 1 units do not take credit for FWCI as a safety system. Therefore, this system is not included in their Inservice Testing Program and is not subjected to any regular testing. Only Millstone 1 takes credit for the FWCI system and performs regular testing of the system and components. Because a small minority of plants employ the FWCI system, this system is only briefly discussed. HPCI and HPCS systems are the more recent and common variations and, therefore, are discussed in some depth.

The purposes of the HPCI and HPCS systems are (a) to permit plant shutdown during a variety of design basis loss-of-coolant accidents (LOCAs), which are smaller in magnitude than those which the low pressure injection systems are designed to handle and (b) to maintain adequate coolant level in the reactor pressure vessel, so that the fuel cladding temperature does not

exceed 1,200°C (2,200°F). The HPCI system can be used to depressurize the reactor vessel and to control the pressure by injecting relatively cool water and by using reactor steam to drive the turbine. The HPCS system accomplishes the same purpose by spraying cool water directly onto the top of the reactor core. A typical HPI system includes a pump, many valves, high pressure piping, two injection water sources, the associated instrumentation, and a steam-driven turbine (HPCI only). The major HPCI and HPCS components, except the inboard isolation valve, are located outside primary containment but inside the reactor building.

HPI systems are normally standby systems. The most common general failure modes for HPI components are leakage and failure to operate as designed. HPI systems are safety systems and, therefore, are frequently tested to ensure operability; however, testing and maintenance procedures 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 are also active during system standby conditions and may act synergistically to degrade components.

The sources of information that were used for this research are the Nuclear Power Experience (NPE) database, the Nuclear Plant Reliability Data System (NPRDS), the Licensee Event Reports (LERs) database, experts in BWR HPI systems, and maintenance and failure data from a specific nuclear plant. The databases were reviewed in detail to determine the dominant failure mechanisms, the most commonly failed components, and the stressors that contribute to aging degradation and failures. Plant-specific data were studied to verify the results of the database analyses. The failure data were then used to plot aging failure rates and to calculate aging fractions. The NPRDS database includes incipient failures that are voluntarily submitted for information only. Approximately 2% of the failure records were classified as incipient, and these were included in the database analyses.

The results of this data analysis show that valves, valve operators, instrumentation and control components, pumps, turbine, pipe, and pipe supports were identified by at least three of the databases as components with significant numbers of failures. A large majority of the failures caused the HPI system to fail to operate as designed; and these failures were typically caused by wear, water hammer, improper lubrication, setpoint drift, or out-of-calibration instrumentation. Each of these failure causes are aging mechanisms or may act in conjunction with other problems to cause aging degradation. Approximately 50% of these failures were detected during testing. A large number of failures were detected during operational abnormalities, maintenance, and routine observations. The only significant variation identified by HPCS failure records was the higher number of instrument failures and related instrument failure causes, such as setpoint drift and out-of-calibration. This is partially related to the design of some HPCS systems that include more instrumentation, such as keep-full systems for lines susceptible to voiding and the use of motor-driven rather than turbine-driven pumps.

Several safety issues have been identified during this research, which are of particular importance for HPI systems. These issues have been identified by the NRC, the Electric Power Research Institute (EPRI), and the nuclear power industry as safety issues of concern. The safety issues concerning valves include the lack of compatibility between valves and their motor operators, poor maintenance strategies, fractured check valve discs, intergranular stress corrosion cracking of valve stems and bolts, backseating of valves, and improper motor operator power cable sizing. The safety issues from Generic Issue II.E.6 and Generic Issue 87 include in situ testing, torque and limit switch settings, and design and operability of safety-related valves.

System reliability has been identified as an issue in which improvement could be appropriate. Three specific conclusions are made that could improve HPI reliability: (a) developing a comprehensive preventative maintenance program for

the system, (b) surveillance-testing of the system, which includes a cold quick-start and a visual examination of the system during testing, and (c) monitoring the opening and closing cycle characteristics of all motor-operated valves (MOVs) following maintenance and before declaration that the valve is ready for service.

Water hammer is another issue that has been identified as a significant source of aging degradation and equipment failures. These events are typically caused by improper isolation valve operation and drain pot and keep-full system problems.

Instrumentation, electrical, pump, and turbine issues have also been identified as significantly affecting system reliability and component failures. Aging degradation, corrosion, and lubricating oil contamination are the primary causes of these problems.

An important part of this aging study is a review of the testing, inspection, surveillance, and maintenance methods currently being applied to detect and mitigate aging failures and degradation. These practices are primarily described in technical specifications, inservice testing programs, and plant-specific documentation. Technical specifications and the American Society of Mechanical Engineers (ASME) Code, Section XI, require periodic testing and examination of the HPI system and mechanical and instrumentation components. These requirements include calibration, verification of operation, functional tests, vibration, flow rates, differential pressures, nondestructive examinations, and system response times. Procedures from the plant-specific data are available to cover calibration, testing, maintenance, and system operation.

Several Probabilistic Risk Assessment (PRA) documents were examined to determine the important events that occur in the HPI system to cause system unavailability, which contributes significantly to increased plant risk. The PRAs used for this task were for the Peach Bottom, Shoreham, and Grand Gulf nuclear plants. The events and component failures considered as being important were those that significantly

contributed to system unavailability and plant core damage frequency. The pump and valves are the components that contribute most to plant risk. A single failure of any one of several components such as the pump, the turbine, the flow controller, or the steam supply valve, will make the system unavailable. Besides being risk-significant components, valves and pumps are items with significant numbers of failures, as shown from the failure data analysis. The risk-significant component designations from PRAs do not take aging into account, but the possibility of aging in some components causes an increased contribution to overall plant risk.

The common thread with most of the codes and standards is that they address guidance and regulatory issues related to the HPI systems, but do not directly consider aging degradation and its effect on the systems. The Code of Federal Regulations addresses the Emergency Core Cooling System (ECCS) in nuclear power plants. These requirements are focused on the design of the systems and the requirements the design must meet such as peak cladding temperatures and testing and inspection capabilities. The NRC regulatory guides set requirements on the design, operation, and quality assurance of HPI systems. The NRC Standard Review Plan provides guidance to NRC staff for performing safety reviews of applications to construct or operate nuclear power plants. This document implements acceptance criteria and guidelines based on meeting the requirements set forth in the ASME Code, Section XI, and the Code of Federal Regulations, including the General Design Criteria. Section XI, Rules for Inservice Inspection of Nuclear Power Plant Components of the ASME Boiler and Pressure Vessel Code, provides rules for the examination, testing, and inspection of components and systems in a nuclear power plant. This section mandates a program of examinations, testing, and inspections to verify adequate safety. The primary HPI system components covered in Section XI are piping, pumps, and valves. The Institute of Electrical and Electronics Engineers (IEEE) generates standards to establish requirements for the safety-related functional performance and reliability of electrical and electronic components

and systems. Many of these standards are considered in the Standard Review Plan and are endorsed by regulatory guides, while others are not specifically endorsed but are recommended for guidance. These codes and standards could be modified to incorporate aging effects and appropriate monitoring methods for aging degradation.

The most common failure modes for HPI components are failure to operate as required and degraded operation. The most common aging failure causes include wear, corrosion, dirt, improper lubrication, improper maintenance, and fatigue. The analysis of the failure data shows that the majority of failures are detected during surveillance and testing. The high rate of failures detected during testing activities indicates a need for more effective aging monitoring programs and also indicates that current surveillance and testing programs could be improved to more effectively detect incipient failures during preventive maintenance. Most of the codes and standards relevant to the HPI systems do not directly consider aging degradation and its effects on system operability and reliability. Modification to include aging degradation considerations for these codes and standards could be considered.

Materials susceptible to stress corrosion cracking may have been used in HPI system valves (e.g., type 410 stainless steel bolting). Problems may be avoided by reviewing the system to identify susceptible materials, by inspecting the components for cracks, and by performing hardness tests on the material. Also, some bolted bonnet swing check valves have 17-4PH, alloy swing arms, and inspection may prevent disc-swing arm separations. Overstressing of the valve stem and valve seat could be prevented by eliminating routine electrical backseating of valves.

The current for MOV torques is much higher than nameplate current, which may have led to undersized cables. Reevaluating the cable sizing to ensure that it is adequate for current at full torque will help ensure motor reliability. Changes in operating and maintenance practices could reduce aging stresses on the HPI system. Implementing a time delay on HPCI high steam flow

isolation logic could reduce spurious isolations immediately after auto-initiation, and those caused by pressure transients and setpoint drift.

Modifying HPCI systems so they will switch to recirculation to the condensate storage tank after water level recovery has been verified would leave the system running and available for immediate return to full service without requiring another startup challenge. This could reduce stresses on the system and system lockouts.

Relaxing HPCI response time to 60 seconds could reduce the wear and aging degradation caused by fast starts.

Use of turbine and pump lubricating oil specified in the vendors' technical manuals will help prevent aging degradation. Routine verification will prevent the use of improper or contaminated oil.

The amount of time the HPCI systems are unavailable because of maintenance increases as the systems and components age. This increased unavailability could be accounted for in the PRA documents for each plant. HPCS unavailability could be monitored to determine long-term trends.

Valves have been identified as the most troublesome component in the HPI systems and,

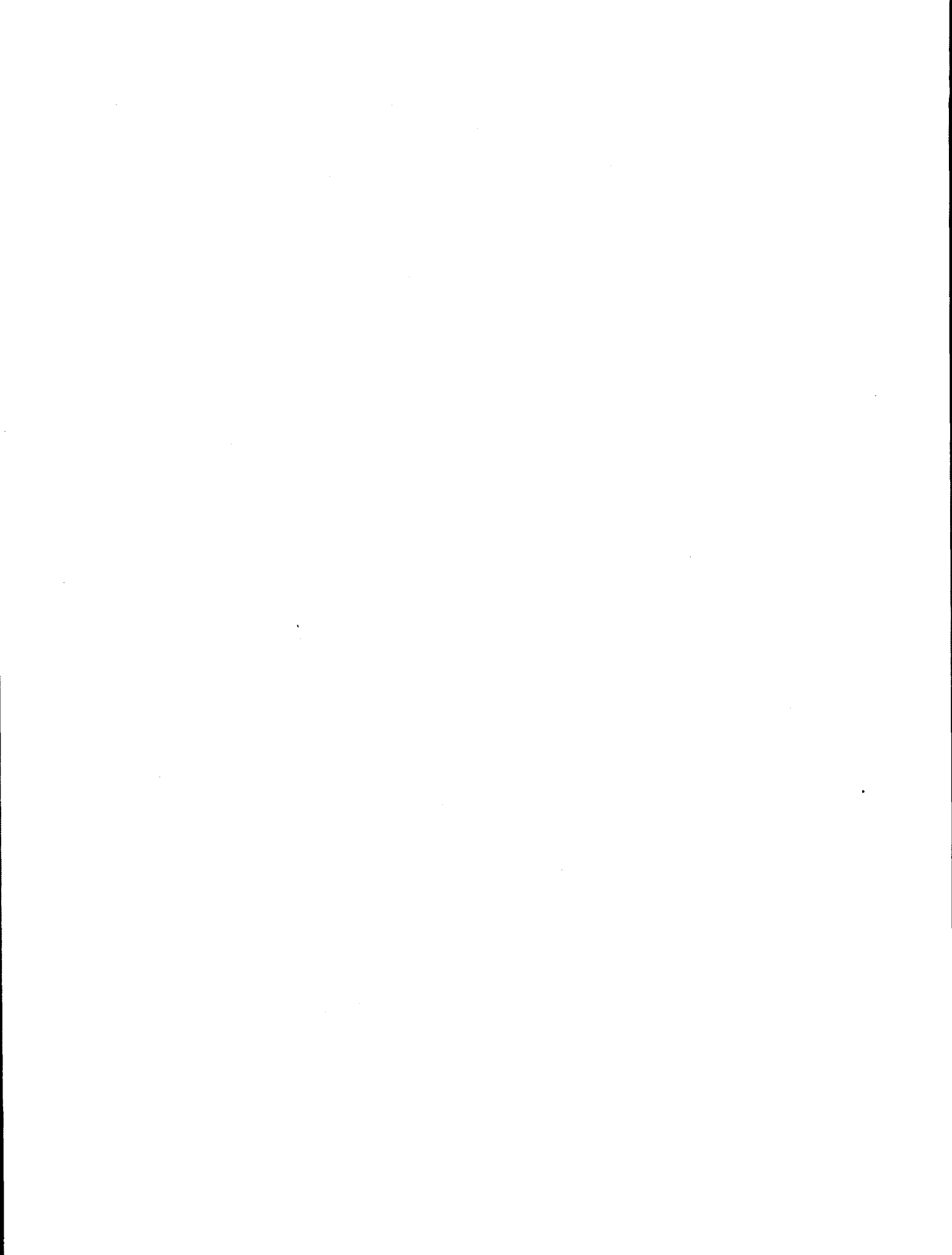
therefore, could be focused on in future research. Performance evaluation of valves is currently underway in several other NRC research programs, and the program to evaluate valve friction changes caused by aging is of particular interest. This program could be extended to include identification of the appropriate actions to be taken by the plant if the aging friction factor is found to be increasing. These actions could then be directly applied to maintenance improvements for the HPI systems.

A detailed review of inspection, testing, and maintenance practices for HPI systems for several operating nuclear plants would identify strengths and weaknesses in current plant programs for detecting and mitigating aging degradation. The results of this research could then be used to provide recommendations, where applicable, for specific inspection, testing, and maintenance activities for detecting, monitoring, and controlling aging effects in HPI systems.

Instrumentation and control component failures were near the top of the list of troublesome components in the HPI systems. Implementing advanced methods for surveillance of aging degradation occurring in electrical components, in power and data cables, and in connections has the potential for reducing failures and ensuring the availability of the systems.

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ACRONYMS

ANSI	American National Standards Institute	INEL	Idaho National Engineering Laboratory
ASME	American Society of Mechanical Engineers	LER	Licensee Event Report
BWR	boiling water reactor	LOCA	loss-of-coolant accident
CST	condensate storage tank	MOV	motor-operated valve
ECCS	Emergency Core Cooling System	NPAR	Nuclear Plant Aging Research
EPRI	Electric Power Research Institute	NPE	Nuclear Power Experience
FWCI	feedwater coolant injection	NPRDS	Nuclear Plant Reliability Data System
GE	General Electric	NRC	Nuclear Regulatory Commission
HPCI	high pressure coolant injection	PRA	probabilistic risk assessment
HPCS	high pressure core spray	PWR	pressurized water reactor
HPI	high pressure injection	RCIC	reactor core isolation cooling
IEEE	Institute of Electrical and Electronics Engineers	SBGT	standby gas treatment

Aging Study of Boiling Water Reactor High Pressure Injection Systems

1. INTRODUCTION

Some commercial nuclear power reactors in the United States have been in operation for more than 20 years. As these power plants have matured, the U.S. Nuclear Regulatory Commission (NRC) and the nuclear industry as a whole has recognized the need for a research program to study the effects of aging on nuclear power plants. The NRC Office of Nuclear Regulatory Research is sponsoring the Nuclear Plant Aging Research (NPAR) Program to meet the need for this research program.

1.1 The Nuclear Plant Aging Research Program

The NPAR Program is a hardware-oriented engineering research program intended to resolve the technical safety issues involved in the aging degradation of electrical and mechanical components, safety and support systems, and civil structures that are part of commercial nuclear power plants. NUREG-1144, Revision 2, describes NPAR and defines aging as "the cumulative degradation of a system, component, or structure that occurs with time, and, if unchecked, can lead to an impairment of continuing safe operation of a nuclear power plant as it advances in age."¹

NPAR research projects employ a two-phase approach to research. This approach is pictured in Figure 1. Phase I uses available information from databases, vendors, open literature, utilities, and expert opinions to produce a report discussing the following areas:

- An identification of failure modes
- An identification of failure causes related to aging degradation
- A review of inspection, surveillance, and monitoring methods, including a

preliminary identification of those that could be improved

- A review of industry codes and standards
- Conclusions identifying potential follow-up work for Phase II.

If the Phase I study identifies the need for additional research to verify or improve continued safe operation, a Phase II study will be implemented. A Phase II study involves some combination of the following areas:

- Tests of naturally or artificially aged equipment or components
- Laboratory or in-plant verification of inspection, surveillance, and monitoring methods
- Conclusions for inspection or monitoring methods to reduce wear from excessive testing
- Verification of methods for determining residual life of components
- Identification of improved maintenance practices
- In situ monitoring of operating components and equipment
- Verification of failure causes from the results of examining in situ, failed, and removed-from-service components and equipment
- Cost/benefit analyses.

When these research studies are completed, they form a technical basis for implementing improved inspection, surveillance, and monitoring methods; modifying industry codes and

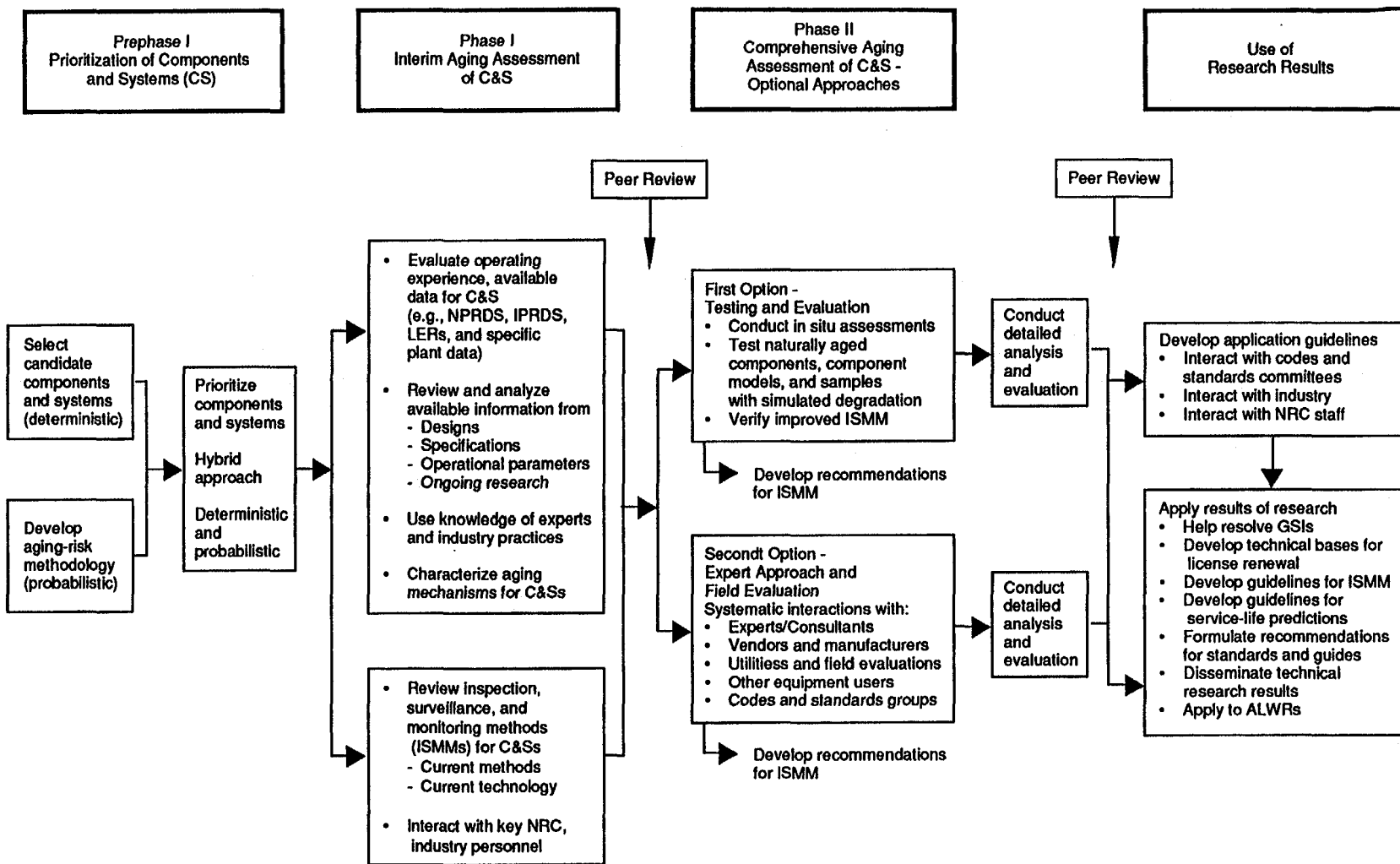


Figure 1. NPAR program strategy.

standards; developing approaches for managing aging degradation; and resolving generic and technical safety issues. Potential end uses of the Phase II research work are shown in the utilization section of Figure 1, and include such things as modifications of codes and standards, resolution of generic safety issues, and guidelines for inservice inspection programs.

1.2 Aging Study on the Boiling Water Reactor High Pressure Injection Systems

This report is the product of a detailed Phase I aging study of BWR HPI systems. This study was performed at the Idaho National Engineering Laboratory (INEL) and followed the NPAR guidelines described above. Related work performed at the INEL includes the pressurized water reactor (PWR) HPI systems report,² the reactor protection system aging study,³ and the 1E power system aging study.⁴ Related work performed at other national laboratories includes the BWR residual heat removal aging study⁵ and the PWR auxiliary feedwater systems aging study.⁶

Information sources for this study included generic databases such as Nuclear Power Experience (NPE), Nuclear Plant Reliability Data System (NPRDS), and Licensee Event Reports (LERs); experts in BWR HPI systems; and maintenance and failure data from a specific nuclear plant. The databases were reviewed in detail to determine the dominant failure mechanisms, the most commonly failed components, and the

stressors that contribute to aging degradation and failures. Data were collected from the records of an operating plant and were studied to verify the results of the database analyses. The failure data were then used to plot aging failure rates and to calculate aging fractions. The knowledge of the experts was drawn on regularly to understand and correlate the failure data.

The first task was determining the various system configurations, defining the system boundaries, and determining the interfaces with other systems for all BWRs in the United States. This work is described in Section 2. Section 3 presents a summary of aging degradation and stressors that cause or contribute to damage and failures in HPI system components. Common component failures, failure modes and causes, and stressors were determined from an in-depth review of the databases and are presented in Section 4 along with the results of the plant-specific records analysis. Several specific safety concerns that apply directly or indirectly to HPI systems are identified in Section 5. Section 6 describes the current testing, inspection, surveillance, and monitoring methods used in a typical BWR plant. Section 7 summarizes the important risk-significant component information from several Probabilistic Risk Assessment reports. Section 8 discusses a comparison between the HPCI system aging study presented in this report and the RCIC system aging study performed by Brookhaven National Laboratory. The current industry and regulatory codes and standards were reviewed and described in Section 9. Section 10 presents the conclusions from this study.

2. BWR HPI SYSTEMS DESCRIPTIONS

The BWR HPI systems are included in the engineered safety features. The engineered safety features are systems that are provided to mitigate the consequences of serious accidents. The systems that make up the engineered safety features and provide this protection are:

- Containment systems
- Emergency core cooling system
- Standby gas treatment system.

The ECCS is made up of several systems including the HPI. The purpose of the ECCS is to provide at least two independent, automatically initiated cooling systems, thus preventing fuel cladding fragmentation for any size line-break accident. This protection must be available for long periods of time (several days) and without offsite power. In addition, the systems must be testable during plant operation. A typical ECCS is shown in Figure 2 and the included systems are:

- High pressure coolant injection or high pressure core spray
- Automatic depressurization—includes pressure relief valves on main steam lines (not shown in Figure 2)
- Core spray or low pressure core spray
- Low pressure coolant injection mode of residual heat removal.

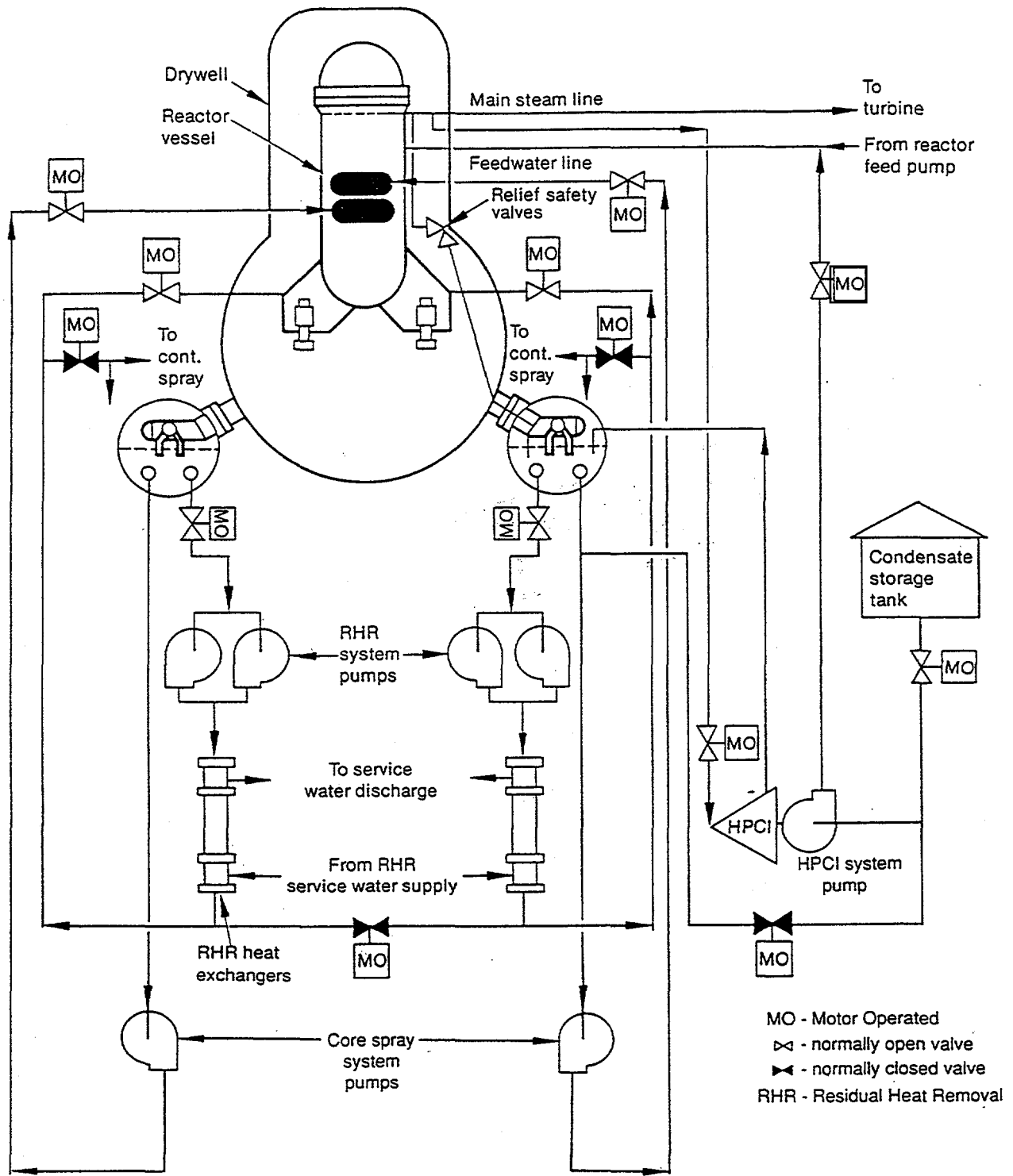
A typical performance capability for the ECCS is shown in Figure 3 for two worst-case scenarios: maximum steam line break and maximum recirculation line break. The results of a complete severance of a recirculation loop line are the most severe of any single line failure inside primary containment because it represents the largest pipe size connected to the reactor vessel at a low elevation. A low elevation break is considered the worst possible case because more coolant mass is lost and less depressurization takes place through a liquid leak than through a two-phase or steam

leak.⁷ Figure 3 shows, for each type of system, the break area that can be fully protected by that single system and the break area for which the system is not singly capable of supplying full protection, thus requiring a combination of one high pressure system and one low pressure system.

The ECCS is initiated by any of three signals indicating high drywell pressure, low-low reactor vessel water level, or low-low-low reactor vessel water level. Only the first two of these signals are automatic initiation sources for the HPI system, which is in standby mode during normal plant operation. The ECCS is powered by a variety of emergency ac power sources, which include off-site ac power, the gas turbine generator, the diesel generator, and the battery system. These power sources may vary depending on the BWR plant class. The classes are currently numbered from BWR/1 to BWR/6. The BWR/1 plants were introduced in 1955 but have since been shut down, and the BWR/2 plants were introduced in 1963. The BWR/3 and 4 plants were introduced in 1966 and 1967, and the newest classes of plants, BWR/5 and 6, were introduced in 1969 and 1972, respectively. The HPI system relies on the following power sources:

BWR class	Power source
2,3	Normal auxiliary power, gas turbine generator, standby diesel generator
3,4	dc power bus
5,6	Normal auxiliary power, dedicated standby diesel generator

Depending on the power plant generation, there are three variations of the BWR HPI system that may be used at each plant. The various systems are known as the feedwater coolant injection (FWCI) system, the high pressure coolant injection (HPCI) system, and high pressure core spray



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Figure 2. Emergency core cooling system.

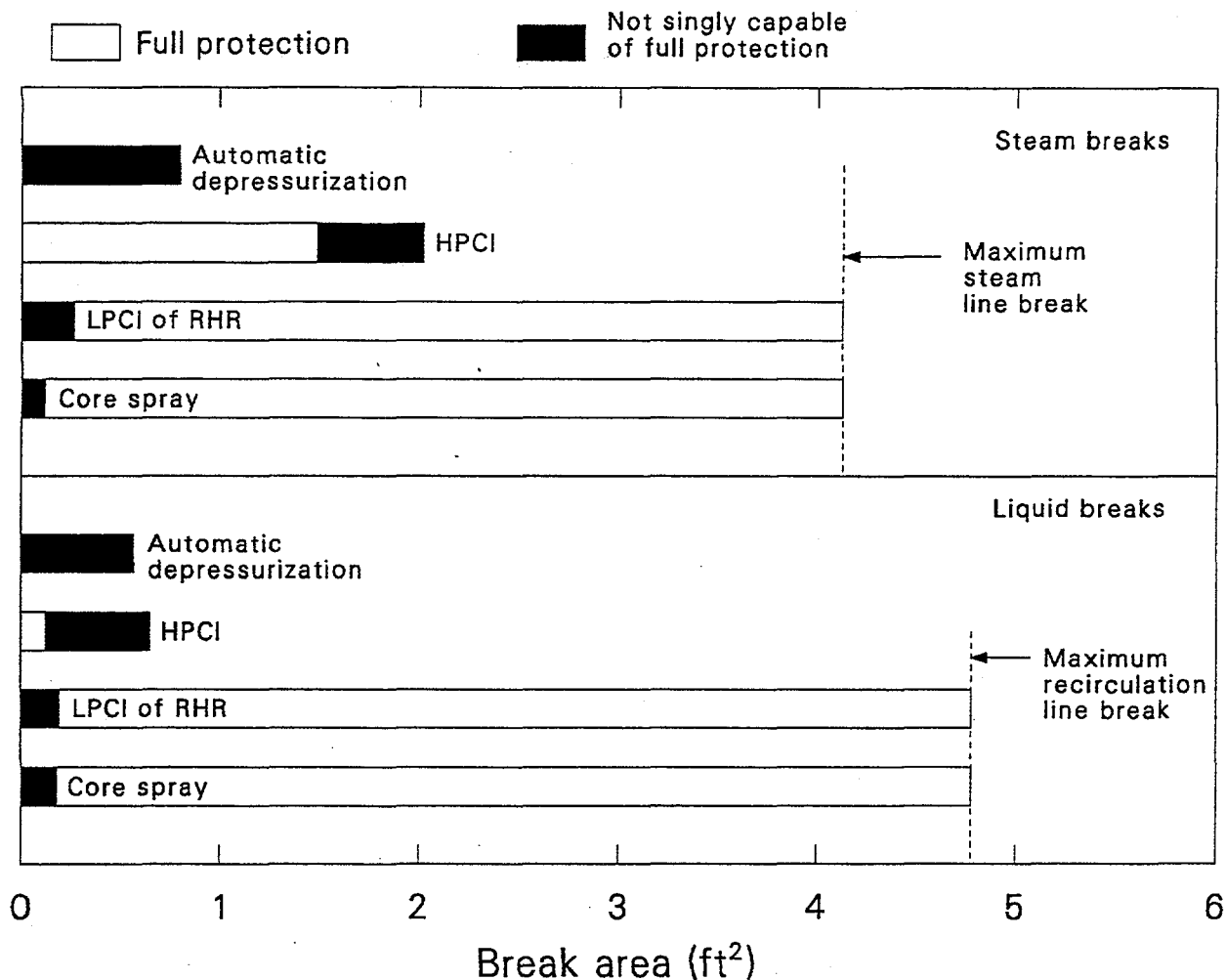


Figure 3. Emergency core cooling system performance for two worst-case scenarios.

(HPCS) system. Each currently operating BWR plant is listed in Table 1 with the class or generation of plant and HPI system type. It is clear from Table 1 that the FWCI system is not very common, and of the three plants that employ this design, the Oyster Creek and Nine Mile Point 1 units do not take credit for FWCI as a safety system. Therefore, this system is not included in their Inservice Testing Program and is not subjected to any regular testing. Only Millstone 1 takes credit for the FWCI system and performs regular testing of the system and components. Because a small minority of plants employ the FWCI system, this system is only briefly discussed. HPCI and HPCS systems are the more recent and common variations and, therefore, are discussed in some depth throughout the remainder of this report.

The plants with HPCS systems are the newest plants and, therefore, are expected to show the fewest number of failures and the least aging degradation. This should be carefully considered while reviewing the failure and time-dependent aging degradation data analysis and results.

2.1 Feedwater Coolant Injection System

The FWCI system uses components of the A and B trains of the existing feedwater and condensate systems. For a description of the aging degradation occurring in BWR feedwater piping, see Chapter 10 of NUREG/CR-4731 Volume 2.⁸ The significant degradation sites identified in the BWR feedwater system include the feedwater nozzles and main steam and feedwater piping at

Table 1. Plant listing identifying class of BWR and type of HPI system.

Plant	Class	HPI system
Oyster Creek	2	FWCI
Nine Mile Point 1	2	FWCI
Millstone 1	3	FWCI
Dresden 2 and 3	3	HPCI
Monticello	3	HPCI
Quad Cities 1 and 2	3	HPCI
Pilgrim	3	HPCI
Brown's Ferry 1, 2, and 3	4	HPCI
Vermont Yankee	4	HPCI
Duane Arnold	4	HPCI
Peach Bottom 2 and 3	4	HPCI
Cooper	4	HPCI
Hatch 1 and 2	4	HPCI
Brunswick 1 and 2	4	HPCI
FitzPatrick	4	HPCI
Fermi 2	4	HPCI
Hope Creek	4	HPCI
Susquehanna 1 and 2	4	HPCI
Shoreham	4	HPCI
Limerick 1 and 2	4	HPCI
LaSalle 1 and 2	5	HPCS
Washington Nuclear Project 2	5	HPCS
Nine Mile Point 2	5	HPCS
Grand Gulf	6	HPCS
Clinton	6	HPCS
River Bend	6	HPCS
Perry	6	HPCS
Type of plant	Total	
FWCI	3	
HPCI	26	
HPCS	8	
Total Plants	37	

discontinuities. Fatigue, corrosion, and erosion-corrosion are the degradation mechanisms that lead to cracks and leaks in the piping and at the nozzles. The FWCI system is designed to assist in reactor coolant system depressurization and to maintain the coolant level in the reactor pressure vessel during an intermediate-sized LOCA. FWCI system action will decrease the reactor coolant system pressure to at least 2.4 MPa

(350 psig) where the low pressure systems, low pressure coolant injection and core spray, can function to prevent core damage.

The FWCI system is shown in Figure 4 with the A and B trains identified. The FWCI flow path starts at the condensate storage tank (CST), continues by the FWCI condensate transfer pump, and then follows the normal feedwater

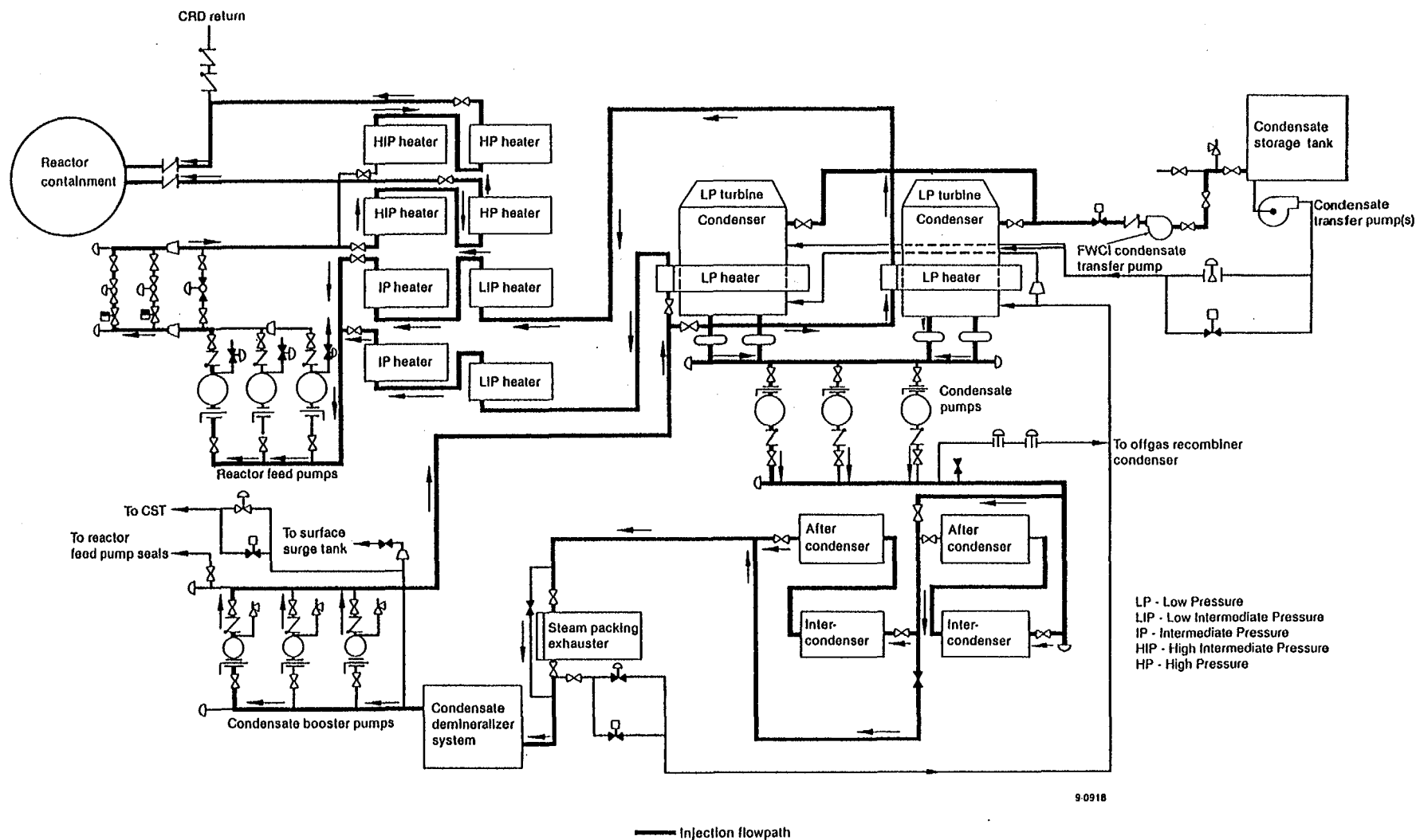


Figure 4. Feedwater coolant injection system diagram showing A and B feedwater trains used as injection paths.

injection flow path. The C train is also shown, but no labels are shown on the pumps because the C train is used only by the feedwater system and not by FWCI.

The following major components of the feedwater and condensate systems are used during an FWCI actuation:

- Condensate transfer pumps
- Condensate pumps
- Condensate booster pumps
- Reactor feed pumps
- Condensers
- Gas turbine generator or standby diesel generator
- Associated valves and piping
- Feedwater spargers.

Offsite power is the normal supply for FWCI components, but during a loss of offsite power, the buses feeding this equipment are transferred to the gas turbine generator and/or the standby diesel generator. Each condensate pump, condensate booster pump, and reactor feed pump is capable of supplying 100% of the rated design flow of 30,280 L/min (8,000 gpm) over a pressure range of 7.76 to 0.69 MPa (1,125 to 100 psig). Within 10 seconds, the standby diesel generator can be supplying the required power, and within 90 seconds, FWCI is at rated flow with all valves fully open. FWCI injects water through the normal feedwater lines and spargers into the annulus region between the core shroud and the vessel wall.

2.2 High Pressure Coolant Injection System

The purposes of the HPCI system are (a) to maintain adequate coolant level in the reactor pressure vessel and (b) to permit plant shutdown during a variety of design basis LOCAs, which

are smaller in magnitude than those which the low pressure injection systems are designed to handle. The system ensures that the fuel cladding temperature does not exceed 1,200°C (2,200°F). The HPCI system can be used for depressurizing the reactor vessel and for pressure control by injecting relatively cool water and by using reactor steam to drive the turbine. Steam will continue to be generated after shutdown by residual stored heat and fission product decay heat. Figure 5 shows a typical HPCI system including a steam-driven turbine driving a booster pump, a reduction gear, a main pump (sometimes considered a pump assembly), many valves, high pressure piping, two injection water sources, and the associated instrumentation. All of the HPCI components, except the inboard isolation valve, are located outside primary containment but inside the reactor building.

The HPCI system is designed to inject 18,900 L/min (5,000 gpm) of water into the reactor pressure vessel over a pressure range of approximately 7.7 to 1.0 MPa (1,120 to 150 psig). The two injection water sources are the CST and the pressure suppression pool. The initial injection source is the demineralized water from the CST. When the CST water has dropped to a preset level or the suppression pool water has risen to a preset level, the pump suction automatically transfers to the less desirable suppression pool water. This provides reactor-grade water to the vessel for cases in which the need for injection is quickly satisfied, and a large water source (suppression pool) for cases in which long-term injection may be required. The injection water is pumped into a feedwater line and injected into the reactor pressure vessel through the feedwater spargers, where it mixes with the hot reactor coolant in the annulus region between the shroud and the reactor vessel wall. Any water leaving the vessel through the leak path causing HPCI initiation drains back to the suppression pool by gravity where it can then be picked up by the HPCI pump, thereby forming a closed system.

The HPCI turbine is driven by steam extracted upstream from the main steam line inboard isolation valve. Normally, steam supply line valves are

normal plant onsite and offsite ac power, except for the inboard steam supply isolation valve, which is ac-powered and normally open, so valve actuation is not required for system operation.

A single failure of the pump assembly, the turbine, the flow controller, or any one of several valves will render the system inoperable. Clearly, aging degradation is a concern in the HPCI system because of the components that would make the system unavailable if a single failure occurred.

The following material describes the important HPCI system components in some detail.^{9,10} Refer to Figure 5 for each of the descriptions. Some typical materials for several major HPCI system mechanical components are listed in Table 2.^{11,12,13} Also included in Table 2 are the major electrical and instrumentation cables, terminals, and connections (see Reference 4).

2.2.1 Booster Pump and Main Pump. 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 through a 2:1 reduction gear unit. All this equipment and the associated piping and valves are mounted on a common baseplate. The booster pump is a single-stage centrifugal pump, and the main pump is a multi-stage centrifugal pump. The booster pump discharges to the suction of the main pump. Typical capacities for each pump are in the range of 15,000 to 19,000 L/min (4,000 to 5,000 gpm) over a reactor pressure range of approximately 1.0 to 7.7 MPa (150 to 1,120 psig). The booster pump has self-lubricating bearings enclosed in large oil reservoirs while the main pump is lubricated by the turbine control and lubricating oil system.

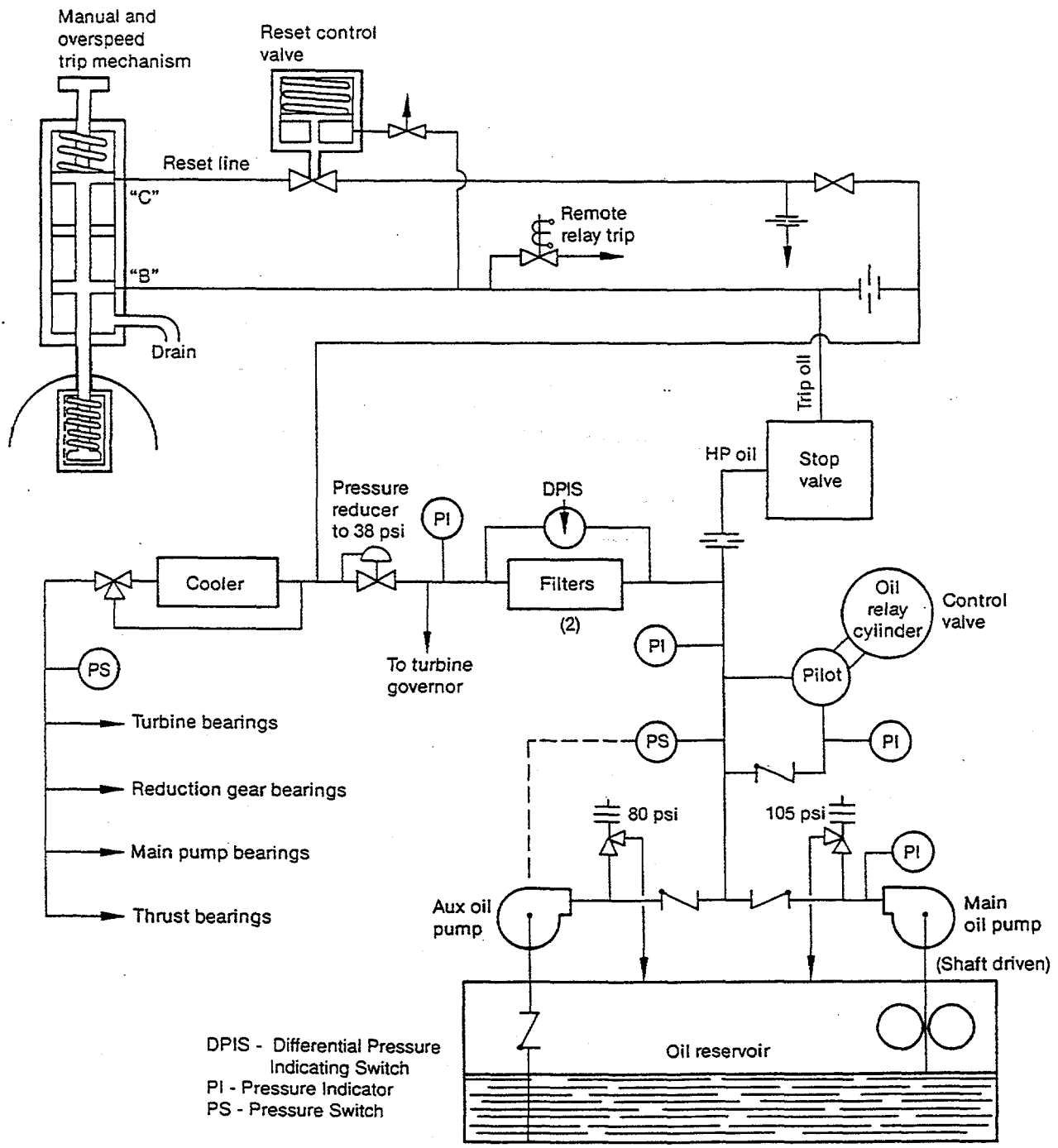
2.2.2 Turbine. The HPCI turbine is a two-stage non-condensing steam-driven turbine typically capable of delivering 3,360 kW (4,500 hp) at 4,000 rpm from an inlet steam pressure of 7.76 MPa (1,125 psi). The turbine provides the power to drive the main and booster pumps. Dry or saturated steam enters the turbine through the turbine control valve and causes the wheel to

rotate. Cast stainless steel reversing chambers, fastened to the turbine casing, reverse the steam's direction, causing the steam to re-enter the turbine blades several times, using nearly all the available energy. The turbine is designed for emergency operation to go from a cold condition to full-rated flow within 90 seconds of receiving an initiation signal. Shaft seals on each end of the turbine shaft, where it projects through the casing, prevent release of radioactive steam to the reactor building. These seals are labyrinth-type packing rings that present a torturous path to steam leakage. The condensate in the seals drains to the gland seal leak-off condenser.

2.2.3 Turbine Lubrication. Figure 6 shows a lube oil layout and the components that are supplied with lubrication from this system. During HPCI startup and shutdown, lube oil is circulated by a 30-kW (40-hp) 250-V dc auxiliary oil pump until the main oil pump, which is driven by the HPCI turbine shaft, develops adequate discharge pressure. When the main oil pump has reached operating discharge pressure during startup, a pressure switch stops the auxiliary oil pump. The auxiliary oil pump is started again during shutdown when the main oil pump can no longer supply the required operating pressure. The auxiliary oil pump may also be manually started. Both pumps draw from the same reservoir that is an integral part of the turbine baseplate. This reservoir typically has a capacity of approximately 590 L (155 gal). Oil is supplied at 0.7 MPa (100 psi) to the turbine stop valve, the control valve operators, and the turbine governor. Another portion of the oil line supplies the turbine bearings, stop valve trip oil, manual and overspeed trip mechanism, reset control valve, main pump bearings, and reduction gear bearings with 0.26-MPa (38-psi) oil. All oil except that going to the turbine control valve and the turbine stop valve passes through a filter. In addition to the filters, the oil going to the turbine bearings and the main pump passes through the lube oil cooler mounted on the turbine base. The lube oil cooler uses water from the booster pump discharge to maintain the oil temperature between 32 and 66°C (90 and 150°F).

Table 2. Typical HPCI system component materials.

Component	Material specification
Pump	
Case	Carbon/alloy steel A 216 Gr. WCB
Bearing housing	Gray iron casting A 278 Cl. 40
Impeller	Stainless steel A 296 Gr. CA15 Stainless steel A 296 Gr. CA40 Stainless steel A 276
Shaft	Stainless steel A 276 Gr. 414
Studs	Stainless steel A 193
Piping	Carbon/alloy steel A 106 Gr. B Carbon/alloy steel A 155 Gr. KC-70, Cl. I Carbon/alloy steel A 333 Gr. 6 Carbon/alloy steel A 106 Gr. C Carbon/alloy steel A 155 Gr. KC-65, Cl. II
Valves	Carbon/alloy steel A 216 Gr. WCB Carbon/alloy steel A 105
Pressure retaining bolting	Stainless steel A 193 Gr. B7 Carbon/alloy steel A 194 Gr. 2H
Turbine	
Core	Carbon/alloy steel A 216 Gr. WCB
Impeller	Carbon/alloy steel A 294 Cl. A5
Shaft	Carbon/alloy steel A 293 Cl. 5
Turbine exhaust rupture disc	Stainless steel Teflon
Gland seal leak-off condenser gasket	Neoprene
Electrical and instrumentation cable	Polyethylene Copper
Terminals and connections	Glass-filled phenolic Stainless steel Polyolefin



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Figure 6. Turbine lubrication system.

2.2.4 Turbine Governor. Turbine speed is automatically controlled by an electronic governor that positions the turbine control valve. The governor operates on signals from the system flow controller, which receives information from the flow indicator in the pump discharge line.

When an HPCI initiation signal is received, the turbine stop valve begins to open on auxiliary oil pump pressure, and the governor begins to open the turbine control valve. The rate at which the control valve opens is controlled by a ramp generator to prevent a turbine overspeed trip. When

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rated pump flow is reached, the flow is maintained by governor action in response to flow variations. A mechanical overspeed trip device trips the turbine at 125% of rated speed by closing the turbine stop valve.

2.2.5 Turbine Gland Seal Leak-Off Condenser. The gland seal leak-off condenser system is supplied as part of the turbine to collect steam, noncondensable gases, and condensate from the turbine shaft seals and the turbine exhaust casing drain. The system includes a gland seal condenser, a condenser blower, a hotwell, and a hotwell drain pump. The system is powered from the 250-V dc battery bank. Steam leakage from the turbine gland seals, turbine control and stop valve stems, and turbine exhaust drainage are collected and condensed in the gland seal condenser. The condensate flows into the hotwell until a high-condensate-level signal starts the hotwell drain pump. The condensate is pumped from the hotwell to the suction side of the booster pump if HPCI is operating, or to clean radioactive waste if HPCI is in standby. Exhaust gases from the condenser are discharged to the standby gas treatment (SBGT) system by the condenser blower. The condensate cooling water is drawn from the booster pump discharge, used for gland seal condenser cooling and lube oil cooling, and then returned to the booster pump suction.

2.2.6 Turbine Exhaust. The turbine exhaust line carries steam from the turbine exhaust to the suppression pool below the water level. This line is normally kept free of water by a system that drains condensate to the gland seal leak-off condenser. Also, a vacuum breaker between the exhaust line and the suppression pool free air prevents a vacuum, caused by condensing steam, from siphoning suppression pool water into the line. The exhaust line is protected from overpressurization by tripping the turbine on a high-exhaust-pressure signal. In addition, two mechanical rupture diaphragms in series will serve as a backup and relieve pressure to the HPCI room. The inboard diaphragm is always exposed to exhaust pressure, but the outboard diaphragm sees exhaust pressure only if the inboard one fails. The inboard diaphragm fails at a

nominal 69 kPa (10 psig), and the outboard diaphragm fails at a nominal 1.0 MPa (150 psig). The space between the diaphragms contains a small leak-off to the HPCI room and a series of pressure switches that will cut off steam to the turbine and isolate the HPCI system upon failure of the inboard diaphragm. This will prevent rupture of the outboard diaphragm and significant release of radioactive steam to the HPCI room.

2.2.7 Valves. The HPCI system includes a number of valves that are dc motor operated, air operated, and hydraulic operated as shown in Figure 5. The MOVs use 250-V dc power for the motors and control circuits. The one exception is the inboard steam isolation valve, which uses 480-V ac three-phase power to operate the valve motor and 120-V ac power for the opening and closing coils. This valve is normally open and, therefore, does not present a problem in the case of a loss of offsite power. An air-operated isolation check valve is installed in the main HPCI pump injection line (see Figure 5) to check reverse flow when feedwater pressure exceeds HPCI system pressure and to open freely when HPCI system pressure exceeds feedwater system pressure. The air operator is used only to test for free valve movement with no differential pressure. The hydraulic operators on the turbine stop valve and the turbine control valve include oil lines, positioning cylinders, and position switches. The oil to operate these valves is supplied by the turbine lubrication system (see Figure 6). These valves open and close in response to HPCI initiation signals, isolation signals, and turbine trip signals, and many of them can also be operated from the control room. Some valves have interlocks that prevent operation unless certain conditions are met. For example, the pump suction valve from the CST and the pump suction valve from the pressure suppression chamber cannot both be open at the same time; also, the minimum flow valve will be open only when flow rate in the main pump discharge line is below a preset value. Each valve consists of the actual valve and the operator that opens and closes the valve. The motor operators incorporate limit switches, torque switches, electrical contacts, and a power unit to drive the operator. When a turbine

trip occurs, the remote relay trip valve opens and drains the hydraulic oil back to the reservoir, allowing the stop valve and control valve to close. The normal valve positions during standby, operation, and testing for a typical HPCI system configuration are listed in Table 3. Some of the normal valve positions for testing and operation are listed as O/C. This indicates that they change position during testing or operation. For example, the minimum flow bypass valve is initially open and then closes when pump discharge is sufficient to inject water into the reactor pressure vessel. The pump suction valves from the suppression pool are initially closed, but then open if the CST empties to a set level.

2.2.8 Piping. Piping in the HPCI system is primarily carbon steel and follows two flow paths as shown in Figure 5. Steam flows through the turbine steam supply line, which branches from the main steam line, and then flows to the pressure suppression chamber through the turbine exhaust line. Injection water is drawn from the CST or the suppression chamber and pumped to the feedwater lines for reactor vessel injection. Alternately, the injection water may go through the minimum flow line to the suppression chamber or through the test line and back to the CST.

Typical pipe sizes include the following:

- Turbine steam supply line: 254 mm (10 in.)
- Turbine exhaust line: 406 mm (16 in.)
- Pump suction line: 406 mm (16 in.)
- Pump discharge line: 356 mm (14 in.).

2.2.9 Instrumentation and Control. Automatic operation of the HPCI system is controlled by electrical signals from level, pressure, and flow instruments. These instruments and their locations are shown in Figure 7. The electrical signals energize logic circuits to produce the control room displays that provide system status and alarms for the operators. The logic and control of the HPCI system is divided into five functional circuits: initiation, auto-isolation, turbine trip, valve control, and alarms.

2.3 High Pressure Core Spray System

The BWR/5 and BWR/6 plants (see Table 1) use a HPCS system for the same purpose as the HPCI system in the BWR/3 and BWR/4 plants—to maintain the reactor vessel water level in the event of a small break LOCA that does not rapidly depressurize the reactor pressure vessel and to limit the fuel cladding temperature. The HPCS pump is a 2,200-kW (3,000-hp) electric-driven centrifugal pump capable of delivering 5,870 L/min (1,550 gpm) at 7.9 MPa (1,147 psi) reactor pressure and 23,100 L/min (6,110 gpm) at 1.4-MPa (200-psi) reactor pressure. The HPCS system components and layout are very similar to the HPCI system described in Section 2.2. Aging degradation of several key components can also cause the HPCS system to be inoperable, just as in the HPCI system; however, the HPCS plants are the newest BWRs and, therefore, have had fewer failures and less aging degradation than HPCI plants. A typical HPCS system is shown in Figure 8,¹⁴ and typical material specifications for several major HPCS components are identified in Table 4.¹⁵ Refer to these with each of the following descriptions.

2.3.1 Spray Sparger. The HPCS system injects water into the reactor vessel through a spray sparger ring mounted inside the vessel above the fuel assemblies. Spray nozzles mounted on the sparger are directed down into the fuel bundles to remove decay heat and maintain the reactor vessel water level. Note that this varies from the HPCI and FWCI injection through the feedwater spargers into the annulus region between the core shroud and the reactor vessel wall.

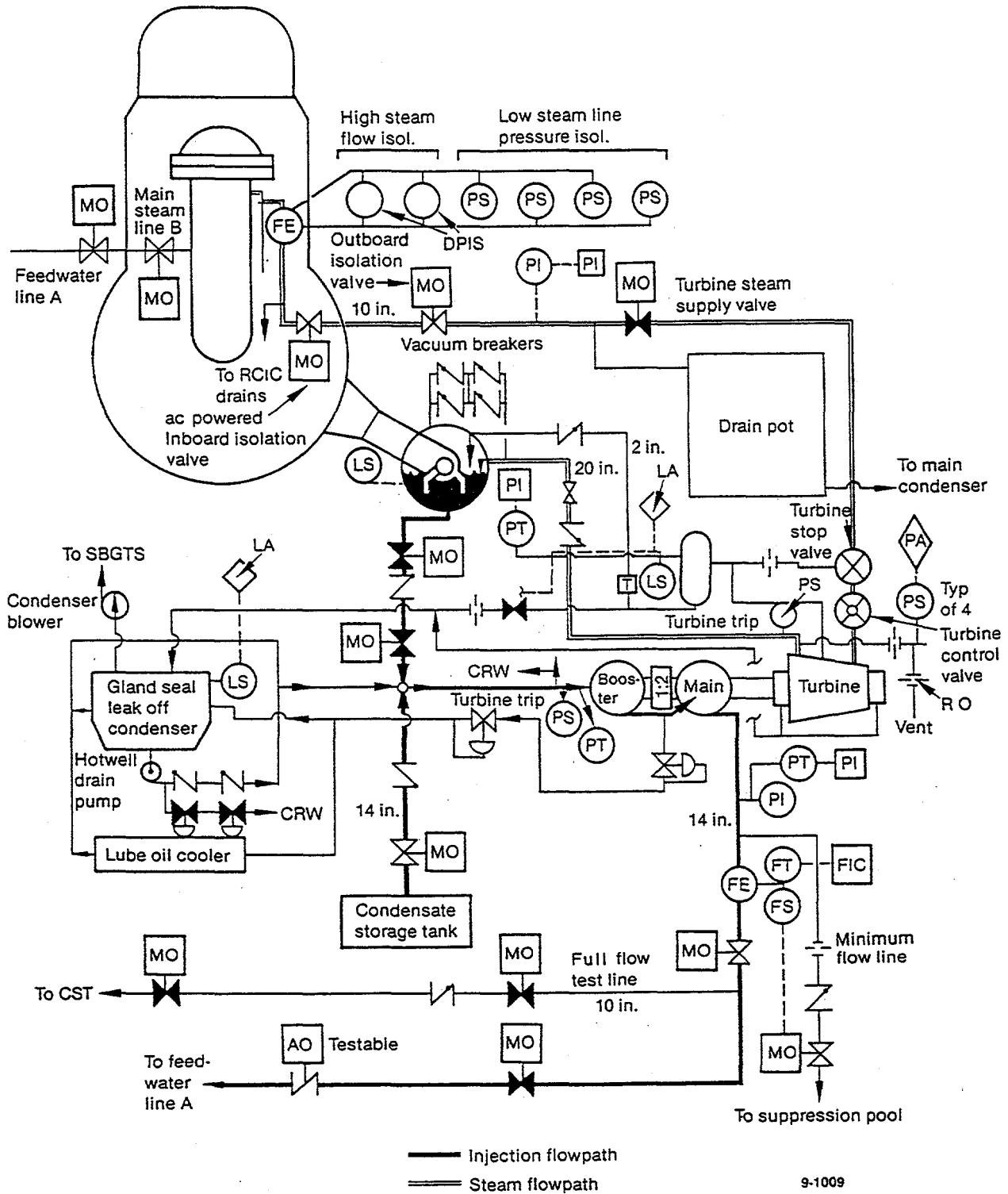
2.3.2 Jockey Pump. The HPCS system is kept full and pressurized by a jockey pump to avoid injection delays caused by filling the injection line, and to prevent water hammer damage to components or piping that could cause the system to be inoperable. The jockey pump is a single-stage, horizontal, centrifugal pump with a maximum capacity of 190 L/min (50 gpm). The jockey pump takes suction from the main pump

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Table 3. Normal valve positions for typical HPCI system configuration.

Valve nomenclature	System configuration		
	Standby	Operation	Test
Steam supply valve to turbine	C	O	O
Steam supply line isolation valve (inboard)	O	O	O
Steam supply line isolation valve (outboard)	O	O	O
Pump suction from condensate storage tank valve	O	O	O
Testable air-operated check valve	C	O	C
Pump discharge valve	C	O	C
Pump discharge valve	O	O	O
Test bypass valve to condensate storage tank	C	C	O
Redundant shutoff valve to condensate storage tanks	C	C	O
Minimum flow bypass valve to suppression pool	C	O/C	O/C
Steam line drain isolation valve	O	C	C
Steam line drain isolation valve	O	C	C
Condensate drain pot drain valve	C	C	C
Condensate drain pot drain valve	C	C	C
Pump suction from suppression pool valve	C	O/C	C
Pump suction from suppression pool valve	C	O/C	C

O—Open
 C—Closed
 O/C—Open/closed



Note: Acronyms are defined on the following page.

Figure 7. Typical high pressure coolant injection system instrumentation locations.

Acronyms for Figure 7

AO	air-operated	LS	level switch
CRW	clean radioactive waste	MO	motor-operated
CST	condensate storage tank	PA	pressure alarm
DPIS	differential pressure indicating switch	PS	pressure switch
FE	flow element	PT	pressure transmitter
FIC	flow indicating controller	RO	restricting orifice
FS	flow switch	RCIC	reactor core isolation cooling
FT	flow transmitter	SBGTS	standby gas treatment system
PI	pressure indicator	TS	temperature switch
LA	level alarm		

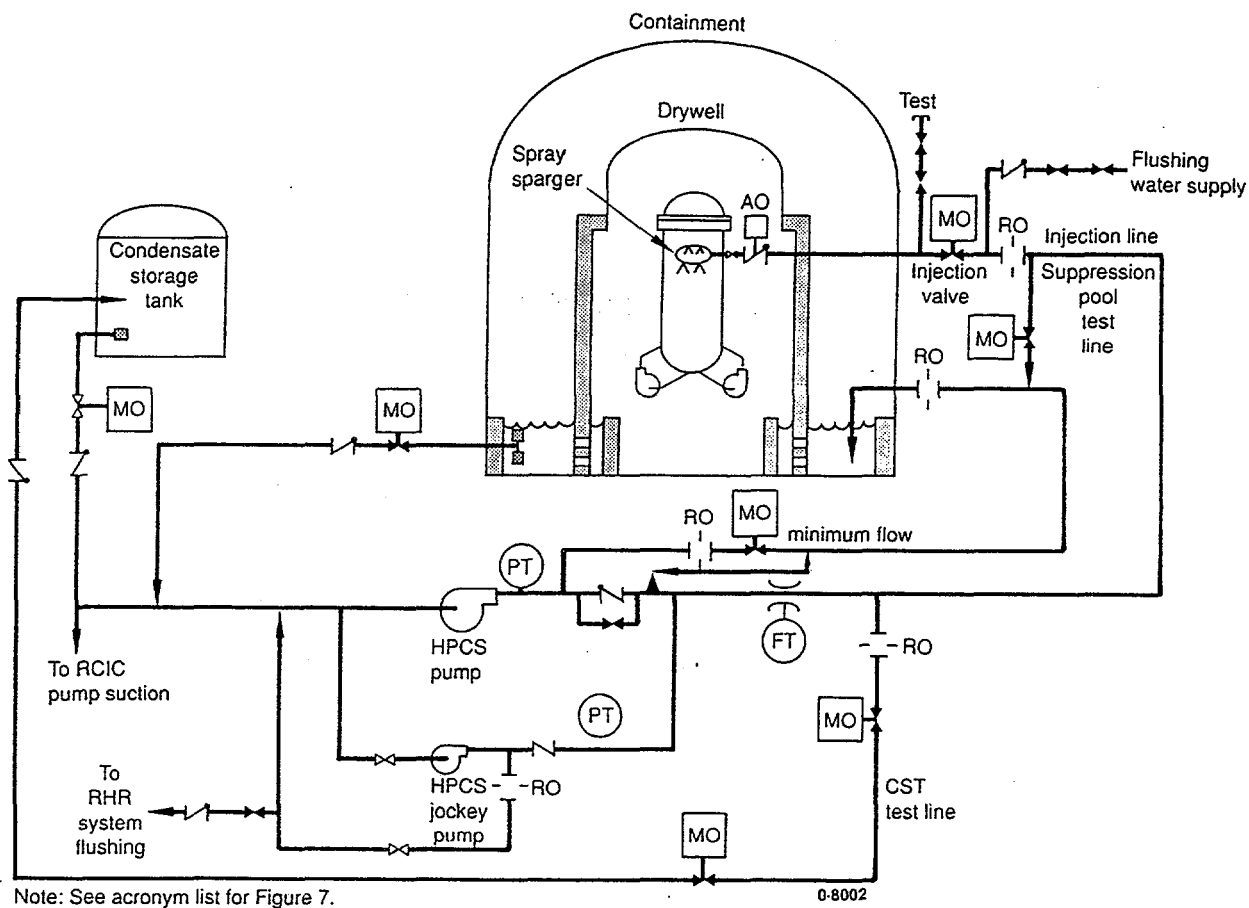


Figure 8. Typical high pressure core spray system flow diagram.

Table 4. Typical HPCS system component materials.

Component	Material specification
Pump	Carbon/alloy steel A 516 Gr. 70
Piping	Carbon/alloy steel A 106 Gr. B
Core spray sparger	Stainless steel A312 Type 304L
Core spray lines	Stainless steel A376 Type 316L
Valves	Carbon/alloy steel A 216 Gr. WCB Carbon/alloy steel A 105
Pressure retaining bolting	Stainless steel A 193 Gr. B7
Electrical and instrumentation cable	Polyethylene Copper
Terminal and connections	Glass-filled phenolic Stainless steel Polyolefin

suction header and discharges downstream of the main pump discharge check valve.

2.3.3 Power Source. The normal source of power for the HPCS system is a regular ac power bus. If regular power is lost, standby power is provided to this bus by a dedicated diesel generator. This HPCS diesel generator has been designated as the alternate ac power source for a specified duration and for recovering from a station blackout at three plants: Clinton, Perry, and Washington Nuclear Project 2.¹⁶

2.4 HPI System Component Safety Classes and Seismic Categories

HPI system components are classified according to ASME Safety Classes 1, 2, and 3 and according to Seismic Categories I, IIA, and II. These classifications describe design, fabrication, construction, and testing requirements and considerations for structures, systems, and components

to ensure safety during normal, upset, emergency, and faulted condition operation.

ASME Safety Class 1 includes pressure vessels, pumps, piping, valves, and component supports that are part of the reactor coolant pressure boundary.^{17,18} Safety Class 2 covers systems and components important to safety that are designed for emergency core cooling, post-accident containment heat removal, post-accident fission product removal, reactor shutdown, or residual heat removal.¹⁹ Class 3 includes systems and components important to safety that are not covered by Safety Classes 1 or 2.

Seismic Category I includes structures, systems, and components important to safety that are designed to remain functional if a Safe Shutdown Earthquake occurs.^{20,21} A Safe Shutdown Earthquake is an earthquake that produces maximum vibratory ground motion and is based on an evaluation of the maximum earthquake potential for the relevant section of the country. The structures, systems, and components covered are those necessary to ensure integrity of the reactor coolant pressure boundary, the capability to shut down the reactor

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and maintain a safe shutdown condition, and to prevent or mitigate the consequences of accidents that could result in offsite radiation exposures. Category IIA structures, systems, and components are designed to Category I or are those whose failure could result in loss of required function of Category I items. Category II covers structures, systems, and components that are not required to maintain structural integrity or function during or after a Safe Shutdown Earthquake.

Numerous exceptions and variations in these classifications exist and are approved by the NRC on a case-by-case basis. However, most of the

HPI systems are in ASME Safety Class 2 and Seismic Category I or IIA. The classification of the major HPI components are identified in Table 5.

2.5 High Pressure Injection System Operations

The HPI system is designed for six fully automatic initiations per year, accounting for corrosion, erosion, and fatigue.²² From 1985 to 1989, the average number of required HPI initiations for all BWRs (from licensee event reports) decreased from 1.7 to 0.8 initiations per plant. This decrease

Table 5. ASME safety class and seismic category classification of major HPI components.

Component	ASME safety class	Seismic category
HPCI turbine	2	I
Pumps		
Main and booster	2	I
Other	—	II
Piping		
Reactor coolant pressure boundary	1	I
Safety-related	2	I
Test line	2	IIA
Within isolation valves	1	I
HPCI turbine drain	2	I
Other	2	II
Piping supports/snubbers	— ^a	I
Valves		
Containment steam isolation	1	I
Steam isolation bypass	1	I
Other	2	I
Electrical modules	—	I
Gland seal leakoff condenser	—	II

a. This is the same ASME safety class as connected piping.

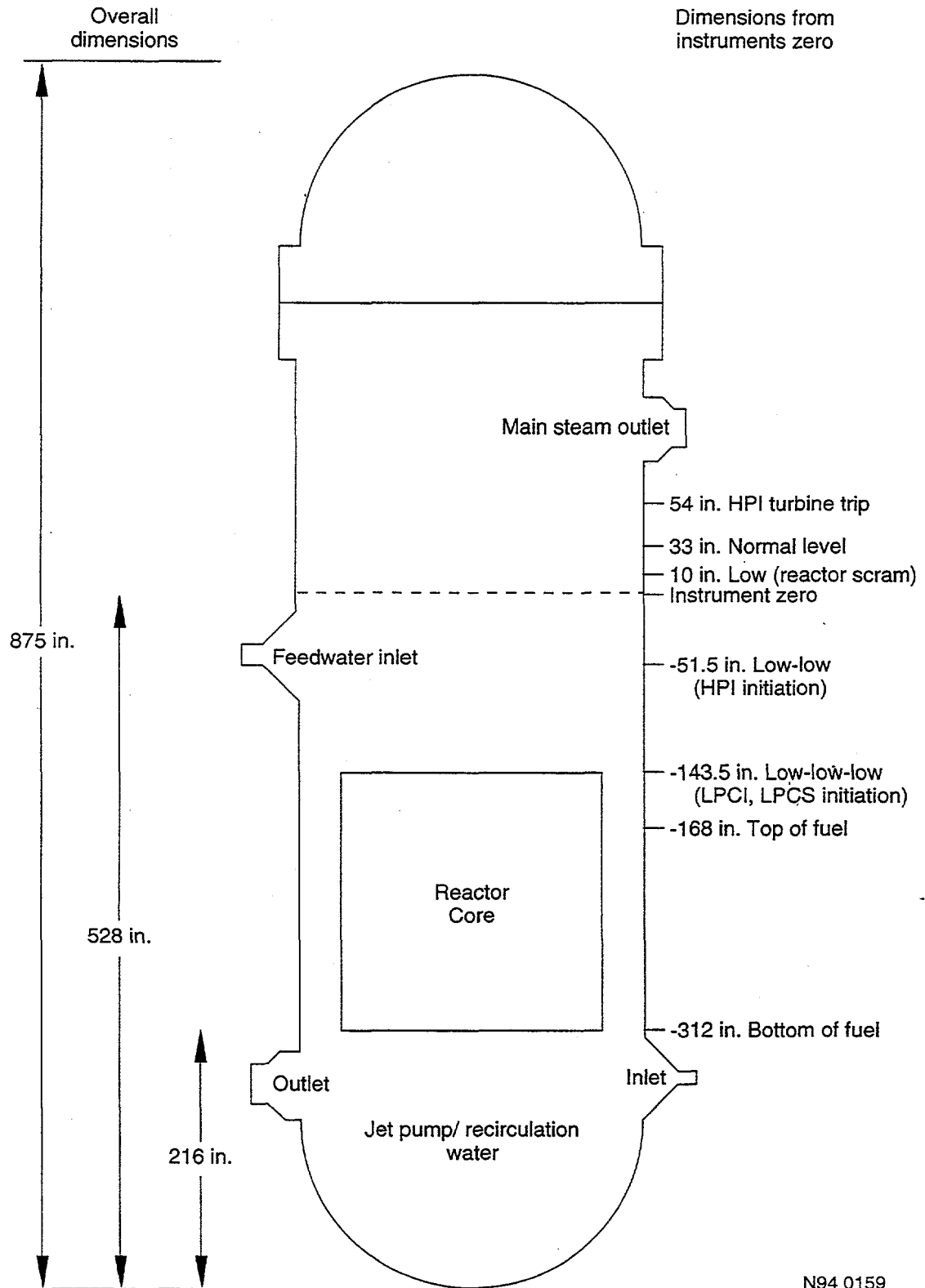
in events is primarily due to increased operating experience. The design features necessary to perform the required safety functions are a means of initiation and shutdown, auto-isolation, and turbine trip. In addition to these features, a means of manual operation is provided. The following sections describe each of these methods of automatic operation of the HPI system.

2.5.1 Initiation and Shutdown. Initiation of the system occurs if a low-low reactor vessel water level signal or a high pressure in the containment drywell signal is received. Contacts in both of these relay circuits are connected in a one-out-of-two-twice logic, which indicates that at least one of the two contacts per circuit must be closed in each circuit for initiation to occur. Typical reactor vessel water level points are shown in Figure 9. A level switch generates a low-low reactor water level signal when the water level is approximately 1.3 m (51.5 in.) below instrument zero, which is approximately 2.9 m (116.5 in.) above the top of the fuel bundles. A pressure switch generates a high drywell pressure signal at 13.8 kPa (2 psi) above the reactor building pressure outside containment. When an HPI initiation signal is received, turbine trips are reset, valves are set to the proper position, and the auxiliary oil pump and the gland seal leak-off condenser are started. As oil pressure increases, the hydraulically operated turbine stop valve and control valve open, allowing the turbine to start up. Pump discharge is directed to the minimum flow line until pressure exceeds reactor pressure. Then the injection check valve opens and high pressure injection begins. The injection will continue until an auto-isolation signal or a turbine trip shuts the system down. The system will shut down, isolate, and seal in the isolation signal if a steam line failure occurs, if high temperature is detected in the steam line space, and if failure of the turbine exhaust inboard rupture diaphragm occurs. Also, the system will shut down and isolate on low vessel steam pressure, but this signal will not be sealed in and allows automatic system restart. The turbine will trip and shut down the system on high reactor vessel water level, turbine overspeed, low pump suction pressure, and high turbine exhaust pressure.

2.5.2 Automatic Isolation. When starting up the reactor, the HPI system is isolated because of low steam line pressure. When the low pressure signal is cleared, typically 0.7 MPa (100 psig), the system configures for normal operation standby mode. If a rupture or a major leak occurs in the steam line, pressure or temperature switches energize relays to isolate the system. An automatic-isolation signal closes the steam line and suppression pool isolation valves and trips the turbine. The signal is sealed in and prevents restart of the system until the isolation circuits are manually reset. Failure of the turbine exhaust inboard rupture diaphragm is detected by pressure switches at 70 kPa (10 psig) and also results in a sealed-in isolation signal. Low vessel steam pressure, 0.7 MPa (100 psig), will generate an isolation signal, but this signal is not sealed in and will allow automatic system initiation if the vessel pressure rises.

2.5.3 Turbine Trip. Turbine trip control signals shut down the turbine and close the minimum flow bypass valve. Turbine trip is accomplished by energizing the remote relay trip to depressurize the trip oil header (see Figure 6). This trip causes the turbine stop valve to close and shut down the turbine. This relay can be energized in the following ways:

- When it is manually energized from the control room
- When the reactor vessel water level reaches the high water level HPI trip point (see Figure 9)
- When the pump suction pressure is abnormally low to prevent cavitation and lack of cooling
- When the turbine exhaust pressure is abnormally high to physically protect the exhaust piping
- When an auto-isolation signal is received, as described above
- When a turbine overspeed signal (125% of rated speed) is received to physically protect the turbine



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Figure 9. Typical reactor vessel water level points and overall dimensions.

- When a manual trip level located on the turbine is actuated.

Since the trip signal is not sealed in, the system can be restored to service if the problem can be quickly identified and corrected. If turbine trip occurs from high reactor vessel water level, it will automatically restart on a low-low water level initiation signal.

2.5.4 Manual Operation. Manual operation may be required under some conditions such as surveillance testing, a low-low reactor vessel water level condition about to occur, or, if the reactor is isolated, using the system to cool and depressurize the reactor during shutdown. If an initiation signal is received during manual operation, the system will automatically realign itself for injection. The HPI system can also be manually shut down from the control room by tripping the turbine and positioning all the valves and switches to normal standby status.

2.5.5 Testing and Maintenance. A variety of testing and maintenance operations are performed on the HPI systems to maintain reliability and safety. Testing and maintenance may require the system to be operating or shut down or some components to be disassembled. Some of the tests include turbine testing, logic system functional tests, flow rate testing, and pump and MOV operability tests. Maintenance includes replacements, repairs, regularly scheduled preventive work, and testing to verify system operability after maintenance work. Testing and testing after maintenance that take place while the plant is operating can contribute to wear and aging in system components and system unavailability; therefore, they need to be carefully considered in a program to control aging. Section 6 will discuss testing and maintenance procedures in more detail.

2.6 System Interfaces

The HPI system boundaries used during this study are those that coincide with each plant's inservice inspection boundaries identified on the piping and instrumentation drawings. The mechanical equipment boundaries were selected

to include the valve or piece of equipment that separates the HPI system from the interfacing system. The electrical power, instrumentation, and control boundaries were set immediately before the first fuse or circuit breaker from the equipment. Recent modifications to system boundaries at some plants may not be reflected because of the age of the piping and instrumentation drawings available at the INEL. Only failures that occurred inside these boundaries were included in this study. At the HPI boundary, there are several systems that interface with the HPI system, but are not part of the HPI system or the ECCS. Various plant designs may include some or all of the same systems, and some plants may include additional plant-specific interfacing systems that are not described in this report. The typical interfacing systems are described in the following paragraphs.

2.6.1 Main Steam. The main steam system provides the HPCI turbine steam through a branch line from a main steam line. This branch is on the upstream side of the inboard main steam isolation valve. If this supply steam pressure is low, the HPCI system will isolate because the pressure is not enough to operate the turbine. The first MOV in the turbine steam supply line after it branches from the main steam line is the HPI system boundary.

2.6.2 Standby Gas Treatment. The SBGT system must be functional for the HPCI system to operate. The SBGT is needed to remove the noncondensibles from the HPCI turbine gland seal leak-off condenser. A dc motor-operated blower pulls the noncondensibles out of the gland seal leak-off condenser and discharges them to the reactor building ventilation system during normal plant operation and to the SBGT system during an accident. This blower is the HPI system boundary. The SBGT system removes radioactive contaminants before releasing the noncondensibles to the environment. SBGT functions independently of HPCI but will automatically initiate on low reactor vessel water level or high drywell pressure to be available for HPCI.

2.6.3 Feedwater and Condensate. The feedwater and condensate system provides the normal

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suction source (the CST) for HPI and the injection path (the feedwater inlet line and sparger for HPCI). A volume of water is normally reserved in the CST for HPI. This volume of water is not available for other feed and condensate supply functions because the piping is arranged to prevent drawing on this volume for any purpose other than HPI suction. The CST also acts as a receptacle for pump discharge flow during pump flow testing. The air-operated check valve in the pump discharge line forms the boundary between the HPI and feedwater systems. The first MOV in the pump suction line from the CST, and the last MOV in the full flow test line to the CST are the boundaries between the feedwater and condensate system and the HPI system. Low suction pressure to the booster pump, caused by low water level in the CST, will cause the pump suction to switch to the suppression pool automatically. A break or blockage of the feedwater line or spargers would prevent HPCI from performing its injection function.

2.6.4 Suppression Pool. The suppression pool supplies an alternate water source to the HPI pump and acts as a receiving volume for the pump minimum flow and turbine exhaust lines. The pump suction line and the turbine exhaust line boundaries are the first valves outside the suppression pool.

2.6.5 Main Condenser. The main condenser receives HPI steam line drainage during normal standby status. The first valve in the line downstream from the drain pots forms the boundary between the HPI system and the main condenser.

2.6.6 Clean Radioactive Waste. Overflow from the gland seal leak-off condenser hotwell and the pump inlet drain pot is pumped to the clean radioactive waste system to prevent water from rising back into lines and causing water

hammer. The first solenoid valve downstream from the hotwell drain pump is the boundary between the HPI system and the clean radioactive waste system.

2.6.7 Reactor Core Isolation Cooling. The reactor core isolation cooling (RCIC) system is a system that is directly related to plant safety, but is not part of the ECCS. RCIC shares a common suction source, the condensate storage tank, with HPI. Portions of the full flow test lines are also common to both systems. The RCIC system is separated from the HPI system by the last valve in the RCIC test line and minimum flow line. The operation and function of RCIC is similar to HPI, but the purposes and capacities are different. RCIC is designed with a much lower capacity for isolation cooling, while HPI is designed as a high pressure ECCS; they share common level initiation and turbine trip setpoints.

2.6.8 Electrical Systems. The valve operators, instrumentation and control components, and the HPCI auxiliary oil pump all rely on the electrical systems for operating power. They depend on offsite power, the 1E power system, dedicated emergency power sources such as emergency diesel generators or gas turbine generators, and dc power buses. The boundary between the HPI system and the electrical systems is the last breaker before the HPI components.

2.6.9 Instrument and Control Air System. Control air is used to actuate the solenoid-controlled air-operated testable check valve in the pump discharge line (see Figure 5). This test feature enables manual operation, with no differential pressure, to verify proper operability under emergency conditions. The boundary between the instrument and control air system and the HPI system is the last valve in the air line supplying the air-operated testable check valve.

3. AGING DEGRADATION AND STRESSORS

Aging degradation occurs in materials subjected to certain stress conditions over time. These degradation mechanisms are very complex because most components are a combination of many different materials, and several stressors may be acting synergistically. In addition, some of these mechanisms have only recently been identified to be acting in nuclear plants and, therefore, are not completely understood. If these mechanisms are not monitored and mitigated where possible, they can limit the life of components and systems and decrease plant safety. Some typical aging degradation mechanisms are fatigue, wear, corrosion, erosion, and embrittlement; some typical stressors include water hammer, testing, maintenance, and operation. Each aging mechanism and stressor affects different materials and components to varying degrees. The following sections describe the potential aging degradation mechanisms and stressors in HPI components that may be affecting plant safety.

3.1 Piping and Pipe Supports

The piping in the HPI system includes the steam line to the turbine, the turbine exhaust line, the pump suction and injection lines, and many smaller lines. These pipe lines vary in diameter from less than 100 mm (4 in.) to greater than 400 mm (16 in.) and transfer high-pressure and high-temperature steam, two-phase water/steam mixtures, room temperature water, or oil for lubrication and hydraulic components. Piping materials may be subject to fatigue, abnormal stress, and corrosion that may lead to wall thinning, leakage, or rupture of the pipe. These failures may range from small leaks to catastrophic rupture of a pipe line, and the results may vary depending on the fluid inside the pipe, the effect on nearby components or the system, and the effect on plant safety.

The pump suction line from the suppression chamber to the first normally closed valve in HPCI and HPCS systems is a potential corrosion site. The water in this section of piping is

typically stagnant because system tests take suction from the condensate storage tank. This is a safety concern because this section of pipe is considered part of primary containment.

HPCS systems include a reactor pressure vessel penetration as part of the piping. This penetration is the line for injection through the spray sparger shown in Figure 8. This site is a specific area of concern because of the potential for high fatigue damage caused by temperature transients. Flow temperatures for this nozzle may go from approximately 57°C (135°F) to the operating temperature of the vessel, which is approximately 288°C (550°F). In addition, the penetration is a potential site for radiation embrittlement because of its proximity to the reactor fuel.

Pipe supports may be mechanical snubbers or hangers or may be hydraulic snubbers. They are used to provide structural support and to restrain and protect pipes from mechanical damage caused by water hammer or earthquakes. Snubbers may be mechanically damaged, preventing lockup; their mountings may be damaged, preventing them from performing their intended function; they may be non-functional because of leakage or improper maintenance; or they may lock up under static loads and cause deformation of piping from thermal expansion.²³ A detailed aging analysis of snubbers has been performed and is documented in NUREG/CR-4279.²⁴

Table 6 summarizes the stressors, degradation mechanisms, and failure modes for HPI system piping and pipe supports. The failure modes may correspond to any or all of the identified stressors and degradation mechanisms. Stressors that cause aging degradation such as vibration and water hammer cause failures in piping and supports.²⁵ Seal degradation has been identified as the most significant stressor causing failures in snubbers (see Reference 23). Water hammer is the result of a void in lines that are normally filled with water, steam condensation in lines containing two-phase flow, entrainment of water in steam-filled lines, and rapid valve actuation. Water hammer in HPI

Table 6. Stressors, degradation mechanisms, and failure modes for HPI system piping and snubbers.

Components	Stressors	Degradation mechanisms	Failure modes
Piping	Water hammer	Fatigue	Cracks
	Pressure	Fatigue	Leaks
	Single-phase flow	Erosion, corrosion, fatigue	Ruptures
	Two-phase flow	Fatigue, corrosion, erosion	Large deformations
	Dirt/foreign material	Erosion	
	Testing	Fatigue	
	Temperature gradients and transients	Fatigue	
	Vibration	Fatigue	
Pipe supports	Seismic	Fatigue, overload	Broken
	Vibration	Fatigue, overload	Failure to lock up
	Seal degradation, leakage	Fatigue, wear	Lock up under static load
	Foreign material	Corrosion, pitting	Pulled out of mounting
	High temperature	Seal damage, blocked internals	Leakage
	High radiation	Seal degradation, leakage	Rotated out of position
	Testing and improper maintenance	Hydraulic fluid degradation	
		Leakage, broken parts, improper adjustments	
Reactor pressure vessel penetration (HPCS only)	Temperature transients	Fatigue	Ruptures
	Pressure	Fatigue	Leaks
	Water hammer	Fatigue	Cracks
	Vibration	Fatigue	
	Radiation	Embrittlement	

systems will be discussed in more detail in Section 5.

3.2 Valves and Valve Operators

Valves and valve operators are subject to a variety of stressors similar to piping. Several additional stressors are present because of the moving parts and the electrical, pneumatic, or hydraulic components. Valves and valve operators are some of the most troublesome components in HPI systems, and aging degradation contributes to much of this trouble. Valves can leak internally or

externally, fail to open, fail to close, fail to operate, or fail to indicate their current position or status.^{26,27} Some of the causes for these failures are failed torque switches; degraded torque springs; burned-out operator motors; failed pneumatic or hydraulic operators; dirty, corroded, or failed limit switches; foreign material; binding; and leakage. Table 7 summarizes the stressors, degradation mechanisms, and failure modes for HPI system valves and valve operators.

Internal and external leakage are the most prominent failure modes, but most leakage

Table 7. Stressors, degradation mechanisms, and failure modes for HPI system valves and valve operators.

Components	Stressors	Degradation mechanisms	Failure modes
Valves	Pressure	Fatigue	Failure to open, close, operate Internal leakage External leakage Bent stem Binding
	Water hammer	Fatigue	
	Operation	Fatigue, wear	
	Temperature	Fatigue	
	Radiation ^a	Lubricant hardening	
	Testing and improper maintenance	Fatigue, wear	
	Dirt/foreign material	Wear	
Valve operators	Contact arcing	Thermal aging	Failure to operate Failure to indicate current position Binding Electrical failure Motor cut out before reaching required torque Motor burnout
	Humidity/water	Shorting, grounding	
	Operation	Fatigue, wear	
	Temperature	Fatigue, lubricant hardening, wiring insulation embrittlement and decrease of moisture resistance, hydraulic and pneumatic line embrittlement	
	Radiation ^a	Lubricant hardening, wiring insulation embrittlement and decrease of moisture resistance, hydraulic and pneumatic line embrittlement	
	Testing and improper maintenance	Fatigue, wear	
	Dirt/foreign material	Poor electrical contact, corrosion	
	High stress	Torque spring degradation	

a. The radiation stressor applies only to valves and valve operators within the drywell.

failures do not prevent the system from performing its design function. Failure-to-operate is the most significant failure mode that affects the system's ability to function and, therefore, affects plant safety. A valve's failure to indicate its

current position is usually cause for declaring the system inoperable because, even though the system may actually be operable, the plant operators cannot determine the status of the valve. Degraded wiring insulation, seals, lubricant, and

hydraulic and pneumatic lines all contribute to failures of valves and valve operators.

3.3 Turbine and Related Components

The HPCI turbine and its lubrication, control, and exhaust rupture diaphragms are exposed to high temperature, pressure, and humidity environments that contribute to failures. The turbine

is subject to wear caused by the steam, water in the steam, and from improper lubrication problems. The control system is affected by the stressors that degrade electronic and electrical systems. The turbine exhaust rupture diaphragms protect the exhaust piping from overpressurization and, therefore, are exposed to the turbine exhaust environment. Table 8 summarizes the stressors, degradation mechanisms, and failure modes for the HPCI system turbine and related components.

Table 8. Stressors, degradation mechanisms, and failure modes for HPCI system turbines and related components.

Components	Stressors	Degradation mechanisms	Failure modes
Turbine	Lubrication problems	Wear	Failure to operate
	Testing and improper maintenance	Wear, fatigue	Failure to achieve required output
	Pressure and temperature	Fatigue/high stress	
	Vibration	Fatigue	
Lubrication subsystem	Dirt/foreign material	Wear	
	Temperature	Lubricant hardening, wiring insulation embrittlement and decrease of moisture resistance	Lubricant hardening Oil leakage Failure to operate Electrical failure Shorts/grounds
Control subsystem	Humidity/water, dirt, etc.	Oil contamination, corrosion, moisture intrusion, wear	
	Contact arcing	Thermal aging	Failure to operate
Rupture diaphragms	Humidity/water dirt, etc.	Corrosion, moisture intrusion, wear	Electrical failure
	Temperature	Wiring insulation embrittlement and decrease of moisture resistance	Shorting, grounding, poor electrical contact
	Pressure variations	Fatigue	Rupture
	Temperature	Diaphragm hardening and embrittlement	Leakage

The primary stressors affecting the turbine are lack of proper lubrication or contaminated lubrication and testing and improper maintenance. Improper maintenance introduces stressors because of imperfect human performance such as incorrectly installed parts or improper adjustments and calibrations. Temperature, pressure, and humidity or water are the significant stressors that degrade the turbine lubrication and control components, and temperature and pressure degrade the exhaust rupture diaphragms.

3.4 Gland Seal Leak-Off Condenser

The gland seal leak-off condenser includes gaskets and electrical and electronic components. The electrical and electronic components include a hotwell drain pump and a blower for removing condensates and noncondensibles from the condenser, and level switches for starting the drain pump when the hotwell is nearly full. Temperature, pressure, and foreign materials are the primary stressors acting on the condenser components. The consequences of gasket leakage are an inoperable system and the probable damage of other nearby electronic components. A failure of the electrical or electronic components also causes the HPCI system to be declared inoperable.

3.5 Booster Pump and Main Pump

The booster pump and main pump are usually considered as an assembly and, therefore, as one pump. They are exposed to the same environment, and the same stressors affect each pump. Those stressors include pressure, lubrication problems, and testing and improper maintenance leading to fatigue, wear, and leakage. A failure of the HPCI pump would cause the HPCI system to be inoperable. Table 9 summarizes the stressors, degradation mechanisms, and failure modes for the HPCI pump.

3.6 HPCS Spray Sparger

The most significant stressors for the HPCS spray sparger include the high-temperature corrosive environment, prolonged exposure to high-neutron fluxes, thermal transients that occur during plant heatup and cooldown, and flow-induced vibrations (see Reference 8). The sparger is located above the fuel region inside the vessel where there is a two-phase mixture of water and steam and the coolant chemistry is not well known. Table 10 summarizes the stressors, degradation mechanisms, and failure modes for the HPCS system spray sparger. Stress corrosion cracking and fatigue are the degradation mechanisms that may result in improper or blocked HPCS flow.

Table 9. Stressors, degradation mechanisms, and failure modes for the HPCI pump.

Components	Stressors	Degradation mechanisms	Failure modes
Pump (main and booster)	Pressure	Fatigue/high stress	Failure to operate
	Lubrication problems	Fatigue, wear	Failure to deliver
	Testing and improper maintenance	Fatigue, wear	required output Leakage
	Vibration	Fatigue	
	Cavitation	Erosion	
Seals	Dirt/foreign materials	Wear	Leakage
	High temperature	Thermal degradation	Failure to operate

Table 10. Stressors, degradation mechanisms, and failure modes for the HPCS system spray sparger.

Components	Stressors	Degradation mechanisms	Failure modes
HPCS spray sparger	Corrosive environment	Intergranular stress corrosion cracking	Improper HPCS flow Blocked HPCS flow
	Radiation	Irradiation-assisted stress corrosion cracking	
	Temperature	Fatigue	
	Flow-induced vibrations	Fatigue	

3.7 Instrumentation and Control Components

The primary instrumentation and control components are cables, relays, connections, switches, transmitters, and indicators. Insulation embrittlement caused by high temperature is the most frequent aging problem occurring in power and control cables. When the insulation becomes brittle, cracks develop from any movement of the cable, and these cracks allow moisture to enter the cable. The degraded insulation then causes conductor-to-conductor shorts or conductor-to-ground shorts (see Reference 4). Connection problems include improper parts and maintenance, cracking of termination lugs, stressing of existing wires when new wires are added, cable testing, corrosion, and loose connections. Switches are subject to contact wear, setpoint drift, and burnout that prevent them from functioning. Some transmitters and indicators are exposed to containment environments where radiation, humidity, and temperature are severe stressors causing aging degradation. Table 11 summarizes the stressors, degradation mechanisms, and failure

modes for HPI system cables, connections, switches, transmitters, and indicators.

3.8 Summary of Aging Degradation

The HPI systems are normally standby systems; therefore, operating stresses are not usually significant. However, testing and testing after maintenance cause many of the same stressors as operation such as wear and fatigue, and because HPI systems are safety systems, they are frequently tested to ensure operability. Technical specifications require a complete HPI system functional test at least every 18 months. Plant-specific procedures may require various system tests as often as monthly or quarterly. High-frequency testing may be a significant proportion of the six initiations per year included in the fatigue design basis. These tests may be contributing to premature failures of some components and wear and aging degradation in some components. The stressors identified in Tables 6-11 may be active during system standby conditions and may be acting synergistically to degrade components.

Table 11. Stressors, degradation mechanisms, and failure modes for HPI system cables, connections, switches, transmitters, and indicators.

Components	Stressors	Degradation mechanisms	Failure modes
Cables and connections	Temperature Radiation Humidity	Embrittlement Embrittlement Conducting path, corrosion	Open circuit Short to ground Conductor-to-conductor short
	Improper maintenance	Cracking/breaking insulation and connections	
Switches and relays	Operation	Wear, fatigue, pitting, arcing	Open circuit Burned contacts
	Vibration	Fatigue, loosening of connections, contact chatter	Arcing across contacts Binding Failure to operate
	Temperature Humidity Foreign materials, contamination	Embrittlement Corrosion Interference, increased resistance and friction	
Transmitters and indicators	Temperature Radiation Humidity	Embrittlement Embrittlement Conducting path, corrosion	Open circuit Short to ground Conductor-to-conductor short Failure to operate

4. REVIEW OF FAILURE EXPERIENCES

The HPI failure experiences discussed in this section were collected from generic databases and plant-specific records. The generic databases include the Nuclear Power Experience (NPE) database, Licensee Event Reports (LERs), and Nuclear Power Reliability Data System (NPRDS). These are the sources of failure information that are supplied by operating nuclear power plants. The plant-specific data are from BWRs with more than 16 years of operation.

The following paragraph discusses some of the strengths and weaknesses common to the databases in this study. Additional comments that apply to a specific database are contained in the individual database sections.

The generic databases contain a large quantity of information representing a large number of nuclear plants. These databases do not include identical information, but each has strengths and weaknesses for use in an aging study; in combination, they contain sufficient information to identify failure characteristics and trends. Some failures may not be reported in the databases because they will not be recognized by the plant until a challenge to the component or system occurs. For example, a check valve disc may be broken off and lying in the pipe downstream, but no problem is identified until backflow through the valve takes place. The databases do not contain a complete and detailed description of every reported failure; in addition, the reporting requirements for some of the databases have changed over time. Therefore, failure frequencies calculated from these data may not precisely match actual failure frequencies; however, because of the large quantity of data and reporting plants, the failure analyses should not be significantly affected. Another weakness inherent in the databases is the variation or interpretation of the codes used to report data and the knowledge and understanding of the person completing the report. By carefully reviewing the failure records and comparing them to plant-specific records, this problem can be minimized, and aging failures can be identified

where the information is available. However, caution must be exercised in considering aging because of the lack of information for identifying aging failures in much of the data and the lack of components over 10 years old. Also, the authors wish to state that data and findings in this report should not be used for any purpose other than that which is expressly discussed herein.

Failure records for BWR HPI systems were collected from each of the four sources identified above. A summary of the data is as follows:

Database	Records	Years covered
NPE	307	1970-1988
LERs	1,829	1980-1989
NPRDS	1,366	1974-1988
Plant-specific	86	1972-1988

The methods and results for the data analysis of each database will be discussed in detail in the following sections.

4.1 Analysis Method

The failure event descriptions collected from each database were entered into a commercial database analysis program for sorting and counting to generate the required information. The NPE database was selected for a detailed manual review of all HPI records because it reports significant safety impacting or generic events and does not include many events of less importance. Each failure record was categorized according to the failed component, failure cause, method of detection, and the effect on the HPI system. Only failure records that occurred within the HPI system boundaries (Section 2.5) were selected. The records from the LER, NPRDS, and plant-specific databases were selected from computerized data retrieval systems and converted to the

database program format that was used. These databases were not reviewed in the same detail as NPE because of the effort required and the schedule limitations.

Two of the three FWCI system plants do not consider FWCI a safety system and, therefore, do not report most failures. Due to this lack of available data, only the failure records for HPCI and HPCS systems were collected and analyzed. These two systems were analyzed independently, except for the NPE data, and the results are presented separately.

4.2 Nuclear Power Experience

The NPE database is a collection of nuclear power plant operating experience, from the public domain, published by Stoller Power, Inc. This database has been in publication since 1972 and includes descriptions of more than 50,000 events. Each event is keyword coded for rapid computerized retrieval and is referenced to the printed description. NPE evaluates current literature and extracts relevant events, particularly those events that are significant from outage-causing, safety, or generic standpoints. Therefore, they are not a complete database attempting to cover all possible events such as those that have no immediate or significant effect on system operability or reliability. Less than 5% of the BWR HPI events recorded in NPE occurred in HPCS systems, and the balance occurred in HPCI systems. Therefore, for the NPE data, the HPCI and HPCS systems were analyzed as a single group. Each failure record was examined in detail, and the relevant information was then entered directly into the database designed for this analysis.

The components that displayed significant numbers of failures in the NPE data analysis are listed in Table 12. Valves and valve operators top the list of failed components; also, switches are components that have a significant failure rate. It is interesting to note that pumps and piping are low on the list of failed components.

Many failure causes were listed for each component in the 307 records reviewed. These causes

Table 12. Summary of combined HPCI and HPCS failures from NPE.

Component	Percent
Valve	30.0
Mechanism (16.6)	
MOV operator (4.0)	
Other operator (1.6)	
MOV motor (7.8)	
Switch	16.1
Gasket	4.6
Rupture disc	4.3
Pipe	4.0
Contacts	2.9
Controller	2.7
Pump	2.7
Governor	2.1
Turbine	1.9
Other components	28.7

are summarized in Table 13. The aging mechanisms that showed up repeatedly were dirt/foreign material, corrosion, fatigue, and wear. Each of these mechanisms cause aging failures or act synergistically with other aging mechanisms to cause failures.

Table 14 summarizes the detection methods identified in NPE records that involve HPCI and HPCS failures. More than 58% of the failures identified were detected during some testing activity. Testing activities include those actions that are intended to ensure reliability of the HPI system, such as technical specification and ASME inservice inspection requirements. The rest of the failures were detected during operation or maintenance, or the detection method was unknown. Because HPI is a standby system, the high rate of failures detected during testing activities indicates that a significant portion of the failures resulted in an unavailability of a

Table 13. Summary of combined HPCI and HPCS failure causes from NPE.

Component	Failure cause	Percent
Valve	Wear	16.7
	Maintenance	16.7
	Loose parts	16.7
	Corrosion	13.3
	Oversize operator	13.3
	Dirt/foreign material	6.7
	Fatigue	6.7
	Other	9.9
MOV operator	Short/burned motor	38.6
	Electrical component failure	18.2
	Dirt/foreign material	15.9
	Binding	6.8
	Design	6.8
	Corrosion	4.6
	Lubricant solidified	4.6
	Wear	2.3
	Loose parts	2.2
	Switch	Setpoint adjustment/drift
Corrosion		19.4
Dirt/foreign material		13.9
Interference		8.3
Other		36.2
Gasket		Overpressurization
	Plant transient	22.2
	Defective	11.1
Rupture disc	Fatigue	54.5
	Water	27.3
	Leakage	18.2

Table 14. Summary of detection methods for combined HPCI and HPCS system failures from NPE.

Detection method	Percent
Testing	58.6
Alarm	7.2
Operational abnormality	2.9
Maintenance	1.0
Troubleshooting	1.0
Unknown	7.5
Other	21.8

component or the system that was unknown until it was revealed by the test. This suggests that there is much room for improvement in detecting incipient failures during preventive maintenance and a need for more effective aging monitoring programs. Testing was particularly effective in detecting aging failures (as defined in Section 3) in valves, valve operators, switches, and turbine exhaust rupture discs.

4.3 Licensee Event Reports

The Code of Federal Regulations (10 CFR 50.72 for occurrences before January 1, 1984 and

10 CFR 50.73 for occurrences after January 1, 1984) requires nuclear power plants to report significant events to the NRC through an LER. LERs filed after January 1, 1984 are only those that are safety-significant events. However, if a component fails but can be replaced or repaired within the time constraint of the limiting condition for operation, an LER is not required.

Table 15 is a summary of the relative number of failures of HPCI and HPCS components identified from the LER database. Valves and valve operators make up more than 25% of all HPCI failures, as expected, since they are the most numerous component in the system. Isolation valves are responsible for 57% of the valve failures. Valves also lead the HPCS list, with isolation valves contributing the majority of these failures. Pumps are the next most-failed HPCS component, which places them higher on the list than in the HPCI system. Pumps fail more often in HPCS because this system includes more pumps and more pump operation than HPCI (see Section 2.3).

While the LER database utilizes 68 cause codes and 30 cause/effect codes, the prominent causes for HPCI and HPCS failures from LER data are listed in Table 16. Resultant component faults and unknown faults are listed more than 80% of the time as the failure cause in the LER database. They describe a component failure that is the result of another failure or that describe an unknown cause, respectively. When these designations are used, the actual cause of the failure may not be described elsewhere in the record. They are not true failure causes but are listed in the tables to show their high rate of occurrence. Water hammer and water spray are aging degradation mechanisms that have been a concern in HPCI systems (see Reference 25). Even though water hammers cause a very small percentage of the failures and are not shown in Table 16, they may cause considerable damage to pipes, pipe supports, snubbers, and fasteners when they do occur. Section 5.4 of this report provides a more detailed discussion of water hammer events. The additional aging degradation causes that show up on the HPCS list are foreign material and

Table 15. Summary of HPCI and HPCS failures from LERs.

Component	Percent
<u>HPCI</u>	
Valves	16.6
Valve operators	9.1
Electric (5.0)	
Hydraulic (2.0)	
Pneumatic (0.9)	
Manual (0.1)	
Solenoid (0.1)	
Unknown (1.0)	
Turbine	8.7
Pumps	5.4
Miscellaneous subcomponents	3.6
Pipe supports	3.2
Pipe	3.1
Seals	2.5
Motors	2.1
Fasteners	1.4
Shaft/stem	1.4
Rupture discs	1.1
Condenser	1.1
Electrical, instrumentation, and control	1.1
Other ^a	39.6
<u>HPCS</u>	
Valves	25.3
Pumps	12.3
Pipe	5.2
Motors	4.6
Miscellaneous subcomponents	3.9
Valve operators	3.3
Hydraulic (1.3)	
Pneumatic (0.7)	
Unknown (1.3)	
Seals	2.6
Pipe supports	1.3
Other ^a	41.5

a. "Other" represents components and faults in the entire system (HPCI or HPCS).

Table 16. Summary of failure causes for HPCI and HPCS systems from LERs.

Component	Failure cause	Percent
<u>HPCI</u>		
Valves	Resultant component fault	88.8
	Unknown	7.2
	Wear/age	0.7
	Electric power loss	0.7
	Other	2.6
Valve operators, electric	Resultant component fault	79.8
	Electric power loss	7.1
	Water	3.6
	Environment	2.4
	Unknown	2.4
	Other	4.7
Turbine	Resultant component fault	93.8
	Unknown	2.8
	Improper lubrication	2.1
	Maintenance	0.7
	Water	0.6
Pumps	Resultant component fault	86.8
	Improper lubrication	4.4
	Water spray, flood, condensation	2.2
	Temporary modification	2.2
	Suction loss	2.2
	Other	2.2
<u>HPCS</u>		
Valves	Resultant component fault	82.0
	Wear/age	5.1
	Foreign object	5.1
	Ineffective previous repair	2.6
	Assembly/adjustment	2.6
	Unknown/other	2.6
Pumps	Resultant component fault	100.0
Pipe	Resultant component fault	25.0
	Corrosion/oxidation	25.0
	Weld-related flaw	25.0
	Foreign object/material	12.5
	Other	12.5

assembly/adjustment problems. Foreign material is a significant contributor to valve seat problems, and assembly/adjustment problems may be a result of improper maintenance.

Table 17 presents a list of the effects of the HPCI and HPCS failures on the overall system. Low flow, failure to operate, and inoperable are the significant effects caused by failures in both systems. The pumps are the major contributor to the low-flow condition, and they also contribute to failure to operate effects. Other components causing low-flow, failure-to-close, and failure-to-operate effects are valves, valve operators, motors, and the turbine. On the average, approximately 11.4% of the failures resulted in the HPCI or HPCS systems failing to operate.

The detection methods that most often identified failures are listed in Table 18. Most failures are detected during testing and operation in both systems. Maintenance accounts for nearly 14% of the detected failures in both the HPCI and HPCS 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. A significant portion of the valve, pump, and turbine failures in both systems are detected during testing, and about 33% of the valve, pump, and turbine failures are detected by operational abnormalities. However, maintenance detects the majority of the seal failures and some other failures such as valves, bearings, and fasteners.

4.4 Nuclear Plant Reliability Data System

The Nuclear Plant Reliability Data System (NPRDS) was developed by the Edison Electric Institute in the early 1970s under the direction of the American National Standards Institute. The NPRDS was maintained by the Southwest Research Institute through 1981. Since January 1982, the NPRDS has been maintained by the Institute of Nuclear Power Operations. The NPRDS records (approximately 93,000 as of

Table 17. Summary of failure effects on HPCI and HPCS systems from LERs.

Failure effect	Percent
HPCI	
Low flow	24.8
Failure to operate	12.3
Inoperable	10.7
External system leakage	5.6
Failure to open	5.0
Cessation of operation	4.6
Break/shear	3.6
Other	33.4
HPCS	
Low flow	33.1
Failure to operate	10.4
Inoperable	10.4
Failure to close	5.2
Other	40.9

Table 18. Summary of detection methods for HPCI and HPCS system failures from LERs.

Detection method	Percent
HPCI	
Testing/inspection	40.5
Operational abnormality	33.2
Maintenance	13.9
Review of procedure/test result	8.0
Unknown	1.4
Audio/visual alarm	1.3
Architect-engineer/vendor notification	0.7
Other	1.0
HPCS	
Operational abnormality	46.8
Testing/inspection	25.3
Maintenance	13.6
Review of procedure/test result	12.3
Unknown	1.4
NRC notification	0.6

Review of Failure Experiences

August 1989) are entered by nuclear plant personnel and are available to members and participants for retrieval of specific information or standard reports according to user-specified criteria.

NPRDS identified a total of 1,366 failure records, of which 1,259 were HPCI events and 107 were HPCS events. These failure records cover more than 300 plant years of BWR operating experience. The distribution among plants is interesting because 63% of the failures occurred in 33% of the plants. This is partially accounted for by considering that the older plants have had more time for failures. However, there are some older plants that have reported a relatively small number of failures. In addition, many of the older plants did not report to NPRDS early in their operating life, and reporting requirements and the type of information that has been reported have changed over the time NPRDS has been in existence. These variations lead to some inaccuracies in the data. However, the overall conclusions should not be significantly affected.

The above distribution of HPI system failures (63% of the failures in 33% of the plants) points out the wide plant-to-plant variation in such programs as preventive maintenance, surveillance testing, etc. This indicates that plants could learn from plants with low failure rates, and that a review of their programs that affect HPI system reliability could identify improvements to these programs.

The NPRDS database includes variations in how similar events are reported. For example, some failures are assigned to components that are not the initial failing component in an event, and sometimes a single failure may be attributed to more than one component. NPRDS includes a single set of codes for simple systems as well as complex systems with redundant trains and components. Therefore, the potential exists for the loss of subsystem/channel, the loss of redundancy, or the loss of system function to be used to describe similar failure events for a single train system such as HPCI or HPCS. As a result, data describing failures may contain some inconsistencies and possibly some inaccuracies. Another factor is that many failures are the result of

system testing or plant trips; however, under design basis events, the challenges to the system may be more severe and certain types of failures may be more prevalent.

Table 19 presents a summary of the failure data from NPRDS for HPCI and HPCS systems. Valves and valve operators are again near the top of the list of most commonly failed components. The instrumentation failures are of particular interest because they are also near the top of the failed components list, but were lower on the lists from the other databases.

The important causes identified by the NPRDS data analysis are listed in Table 20. Calibration and setpoint drift are instrumentation failure causes that are near the top of both lists. It is particularly interesting to note that wear is one of the leading causes for the HPCI and HPCS system valves and valve operators. Time-related material degradation is also an important failure cause identified by NPRDS. This category covers degradation of mechanical properties without significant material loss as from wear. Included mechanisms are cyclic fatigue cracking, radiation damage, and embrittlement. Abnormal stress describes failure causes such as vibration, water hammer, high temperature, and high pressure. Considering wear, abnormal stress, and time-related material degradation as the mechanisms that conform to NPAR-defined aging, the NPRDS data indicate that aging degradation is an important failure cause in HPI systems.

The effects on the HPCI and HPCS systems from the failures identified in Table 19 are presented in Table 21. Clearly, a large majority of the failures in both HPCI and HPCS systems have no significant effect on the system. A major reason for this is that many small leaks or instrumentation and control component failures are identified and repaired before causing a total system failure, and many of the failures that do occur are in redundant components and therefore do not cause system unavailability. However, most component failures, including redundant components, cause a clear loss of reliability that increases the risk of the HPI system being unable to perform its

Table 19. Summary of HPCI and HPCS failures from NPRDS.

Component	Percent
<u>HPCI</u>	
Valves	28.4
Instrumentation bistable/switch	17.0
Valve operators	15.8
Instrumentation, transmitter/primary/detector/element	11.8
Pipe supports	5.2
Closers/interrupters	3.7
Turbines	3.6
Instrumentation, controllers	2.9
Other	11.6
<u>HPCS</u>	
Instrumentation bistable/switch	35.5
Valves	16.8
Instrumentation, transmitter/primary/detector/element	12.2
Valve operators	10.3
Closers/interrupters	9.4
Pipe supports	6.5
Instrumentation, indicators/recorders	3.7
Other	5.6

Table 20. Summary of HPCI and HPCS failure causes from NPRDS.

Component	Failure cause	Percent
<u>HPCI</u>		
Valves	Wear	45.3
	Mechanical damage/binding	9.7
	Time-related material degradation	7.7
	Out of mechanical adjustment	6.0
	Incorrect material	5.3
	Dirty	4.4
	Other	21.6
Instrumentation bistable/switch	Setpoint drift	35.9
	Out of calibration	12.4
	Dirty	6.6
	Wear	5.0
	Mechanical damage/binding	5.0
	Other	35.1

Table 20. (continued).

Component	Failure cause	Percent
<u>HPCI (continued)</u>		
Valve operators	Wear	13.1
	Out of mechanical adjustment	10.3
	Burned out	9.2
	Mechanical damage/binding	8.2
	Connection defective/loose parts	6.7
	Previous repair	5.7
	Short/grounded	5.7
	Dirty	4.6
	Open circuit	4.6
	Abnormal stress	4.3
	Other	27.6
Instrumentation transmitter/primary/ detector/element	Out of calibration	27.6
	Setpoint drift	15.9
	Wrong part	13.6
	Circuit defective	7.0
	Dirty	5.6
	Other	30.3
<u>HPCS</u>		
Instrumentation bistable/switch	Setpoint drift	47.1
	Out of calibration	42.7
	Other	10.2
Valves	Mechanical damage/binding	20.7
	Wear	17.2
	Abnormal stress	13.8
	Out of mechanical adjustment	13.8
	Previous repair	6.9
	Dirty	6.9
	Connection defective/loose parts	6.9
	Other	13.8
Instrumentation transmitter/primary/ detector/element	Out of calibration	52.6
	Setpoint drift	36.8
	Foreign/incorrect material	10.6
Valve operators	Out of mechanical adjustment	37.5
	Mechanical damage/binding	18.8
	Wear	12.5
	Other	31.2

Table 21. Summary of failure effects on HPCI and HPCS systems from NPRDS.

Failure effect	Percent
<u>HPCI</u>	
No significant effect	39.8
Degraded system operation	24.9
Loss of subsystem/channel	19.7
Loss of system function	11.2
Loss of redundancy	4.4
<u>HPCS</u>	
No significant effect	38.3
Loss of subsystem/channel	27.1
Degraded system operation	23.4
Loss of redundancy	5.6
Loss of system function	5.6

intended function for the required period of time, thereby increasing total plant risk. Degraded system operation and the loss of a subsystem or channel are the other important effects that result from component failures. It is also noted that, on the average, 10.8% of the failures in the HPCI or HPCS systems resulted in a loss of system function.

Detection methods that identify most failures in both HPCI and HPCS systems are shown in Table 22. The sequence of methods is exactly the same for both systems, and testing leads the list. Surveillance testing detected about 50% of HPCI component failures and 66% of HPCS component failures in nearly all components such as instrumentation, valves, and valve operators. Failures detected through operational abnormalities are a significant proportion of the detection methods that could be reduced by improving some of the detection methods further down the list such as preventive maintenance and inservice inspections or by developing improved monitoring methods.

An additional piece of information available in the NPRDS database is the failure severity level, which describes the failure with one of three

Table 22. Summary of detection methods for HPCI and HPCS system failures from NPRDS.

Detection method	Percent
<u>HPCI</u>	
Surveillance testing	49.2
Routine observation	14.1
Operational abnormality	11.6
Special inspection	7.0
Audio/visual alarm	5.5
Preventive maintenance	4.7
Incidental observation	4.2
Inservice inspection	3.3
Other	0.4
<u>HPCS</u>	
Surveillance testing	66.4
Routine observation	9.4
Operational abnormality	7.5
Special inspection	5.6
Audio/visual alarm	4.7
Preventive maintenance	2.8
Incidental observation	1.8
Inservice inspection	1.8

possible categories: immediate, degraded, or incipient. The immediate category failures are those that are sudden and complete such as failure of the turbine steam supply valve to open. Degraded failures are those in which a gradual or partial loss of ability to perform a required function has occurred; one example is a condensate storage tank level switch that is damaged and does not activate at the correct setpoint to switch HPCI pump suction to the torus. Incipient failures describe components in a condition that could result in a degraded or immediate failure if corrective action is not taken. These failures are not required to be reported to NPRDS, but some utilities voluntarily share this information because of possible generic implications. An example of an incipient failure is an HPCI turbine bearing showing increased vibration caused by excessive wear but not exceeding vibration or temperature limits. NPRDS records analyzed for this study included

70% degraded failures, 28% immediate failures, and 2% incipient failures. These data indicate that most failures have no immediate system effect, and the system continues to function; however, they cause degraded system operation and reduce system reliability. Also, the 28% immediate failure rate is large enough to be of concern, regardless of the number of degraded failures reported.

4.5 Plant-Specific Data

We visited the engineering offices of one of the older BWR plants to collect a large amount of operating experience, maintenance, and testing records. This plant has an HPCI system (BWR/3 generation) and is a nuclear unit with more than 16 years of operating experience. The data collection and analysis, which was performed by a subcontractor for another NPAR project, focused on equipment failures caused by aging.²⁸ The operating, testing, failure, and maintenance documents were also examined for all the HPCI components. The examination included all documented incidents of component degradation and repair from the plant work request and maintenance history files. Also, interviews were conducted with the system engineer, the instrumentation and control engineer, and the operators

to obtain the historical performance background for the HPCI system. The maintenance request documents were determined to be the best source of failure information. Other documents such as maintenance work orders, work request permits, failure and malfunction reports, abnormal occurrence reports, unusual occurrence reports, LERs, plant design change reports, field disposition instructions, post outage reports, pump flow rate and valve timing test data, and instrumentation and controls maintenance documents were used as supporting and backup resources.

A maintenance request is written whenever significant maintenance is required on any mechanical or electrical component. Therefore, the maintenance request provides a history of all significant adjustment, repair, and renewal of components. The disadvantage of the maintenance request is the lack of detail in some of the malfunction and repair descriptions. Because some of the descriptions were brief, it was sometimes difficult to reconstruct a specific failure. When necessary, the supporting documents described above were used to understand the failure.

Table 23 summarizes the significant component failures from the 86 failure records

Table 23. Summary of HPCI failures from plant-specific data.

Component	Percent	Mean time between failures (in years)
Turbine steam supply MOV	12.4	1.7
Turbine and pump	10.1	1.6
Pipe supports	10.1	1.6
Turbine control valve	5.6	2.8
Turbine stop valve	4.5	2.8
Pump suppression pool isolation MOV	3.4	3.6
Turbine exhaust line containment isolation valve (No. 45)	3.4	4.1
Turbine exhaust line containment isolation valve (No. 74)	3.4	4.9
Relays and coils	3.4	3.5
Pump injection testable air-operated valve	2.3	4.7
Full flow test MOV	2.3	4.5
Gland seal leak-off condenser hotwell drain pump	2.3	4.7
Gland seal leak-off condenser blower	1.1	7.0
Other	35.7	—

collected for the plant's HPCI system. Table 23 also includes a calculation of mean time between failures from plant-specific data. However, the small number of failures for many of these components makes the statistical confidence in these values very low. Valves clearly dominate the list, and in fact all valves grouped together make up more than 37% of the total failures. When the turbine and pump are considered as an assembly, their position on the list closely agrees with the other databases. Pipe supports appear to be more significant in the plant-specific records than in the other databases. This is caused by many failures included in the maintenance request system that were not considered important enough to report to the other failure record systems and by reports of incipient failures discovered during major pipe support maintenance programs. Events listed in the maintenance requests provide a view of day-to-day problems with HPCI components and therefore should reflect the actual effects of aging degradation. Many of these problems are taken care of through repair or replacement before they cause a complete loss of the HPCI system. A review of the maintenance requests for events involving valves, valve operators, instrumentation and control components, pumps, turbines, piping, and pipe supports revealed some common events and failure causes as shown in Table 24. As expected, the most common valve problems are packing leaks that are stopped by packing adjustment or replacement. Body-to-bonnet gasket leak is another valve problem that requires partial valve disassembly to replace the gasket. Motor failures in valve operators are the most common problems, but the number of failures in the maintenance requests reviewed is too small to be statistically significant. The number of failures is also too few to draw any conclusions for pumps and turbines. All piping failures are leaks, and most of these leaks are stopped by replacing the damaged portion of pipe. Most pipe support failures are caused by parts that become loose or by improper maintenance or installation.

A total of 89 failures were identified for 52 components. The significant failures were distributed as shown in Table 23, while 15 component

failures were considered insignificant and 24 components had no failures. During shutdown, 15 failures occurred, and the other 74 failures took place while the plant was operating. The operating failures were further classified according to the effect on the component and system as follows:

- Functional failures: 91.9%
- Administrative decision to disable: 2.7%
- Uncertain: 5.4%.

Clearly, the only significant category is the functional failures that prevent the component from performing its intended function.

The number of failures per operating hour per year from 1974 to 1985 from the plant-specific data is shown in Figure 10. Data from 1986 through 1989 are not shown because the plant was in an extended maintenance outage during that time. The slightly increasing failure rate through the middle portion of the chart may indicate that accelerating aging took place in HPCI components.

4.6 Time-Dependent Failure Data

The 1,366 NPRDS failure records were analyzed according to component failures separated into groups by component age at the time of failure. This provides an overall view of the component age at failure and the number of failures for each age category. However, the NPRDS records on component age at failure are not a reliable source of this information because of the reporting requirements that make updating this field optional under certain circumstances. Such circumstances include replacing identical components and components that are frequently removed and reinstalled in other locations such as circuit breakers. With this knowledge and caution, the records were used in the time-dependent failure analysis because NPRDS is the only source of component age data available. Replacements were not considered for HPI system

Table 24. Results of maintenance request reviews to determine failure causes.

Component	Event or failure cause	Number of events	Percent
Valves	Packing leak	24	61.5
	Body to bonnet gasket leak	8	20.5
	Internal leak	2	5.1
	Exceeds allowable operating time	2	5.1
	Oil leak	1	2.6
	Binding	1	2.6
	Missing stud	1	2.6
Valve operators	Motor failure	3	50.0
	Moisture ground	2	33.3
	Torque switch	1	16.7
Instrumentation and control	Limit switch failure	7	17.1
	Gauge failure	6	14.6
	Turbine control	6	14.6
	Pressure switch failure	5	12.2
	Loose/broken parts	3	7.4
	Failed breaker	2	4.9
	Blown fuse	2	4.9
	Water	2	4.9
	Binding	1	2.4
	Power supply failure	1	2.4
	Transmitter failure	1	2.4
	Other/unknown	5	12.2
Pumps	Oil leak	2	50.0
	Gasket leak	1	25.0
	Unknown	1	25.0
Turbine	Steam leak	1	100.0
Pipe	Leak-replaced	10	47.6
	Leak-repaired	5	23.8
	Gasket leak	6	28.6
Pipe support	Loose parts	8	38.1
	Improper installation/maintenance	5	23.8
	Out of adjustment	4	19.0
	Bent/broken	3	14.3
	Corrosion	1	4.8

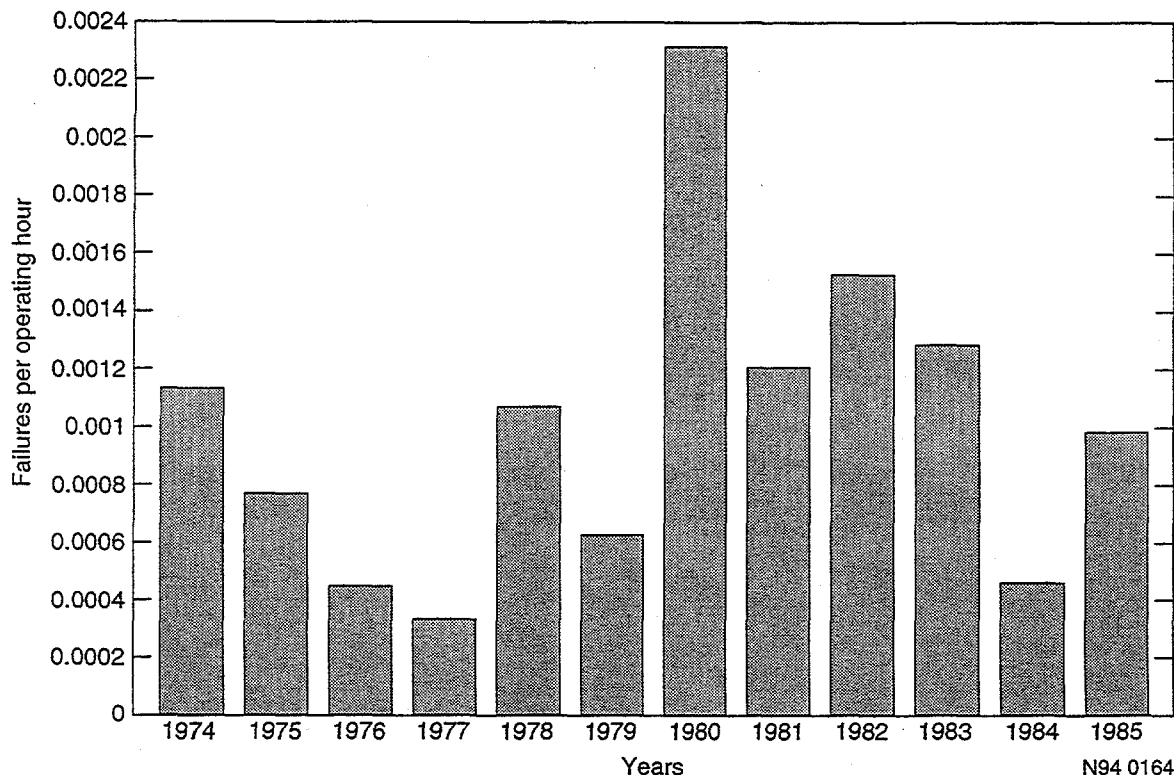


Figure 10. Plant-specific total failures per year.

components because consistent information has not been reported for many replacements. However, replacement frequency is a factor that influences failure data. No attempt was made to normalize the number of failures to the number of plants or components because this would require simultaneously considering the date of each event, the number of plants old enough to have each failure, which of these plants were reporting to NPRDS, and the number of each type of HPI component in each plant. To avoid the significant effort involved in normalizing the data as just described, the aging fraction was calculated for specific components in component age categories. The aging fraction is the ratio of aging failures to total failures for the group of component failures that occurred at the same component age. The determination of which failures are considered aging was made by using the definition applied to NPRDS data in an aging failure survey done for the NPAR program in 1988.²⁹

Figure 11 shows the total number of failures and the number of aging failures plotted against the age of the component at the time of the failure. The aging failures curve closely follows the total failures curve, indicating that the number of aging failures relative to total failures remains relatively constant over the plant life period plotted. The numbers of both aging and total failures drops very low beyond approximately 15 years because the population of components that old is very small. Figure 12 shows the aging fraction as a function of the component age at the time of failure. The graph shows a trend that increases slightly to about ages 10 to 12 years then decreases. One factor in this trend is the repair and replacement of aged components and the period of decreased aging failures that follows. In addition, this decrease could be caused by the small number of plants older than 10 years reporting too few events to be a good statistical sample. Insufficient data is the most likely cause of the

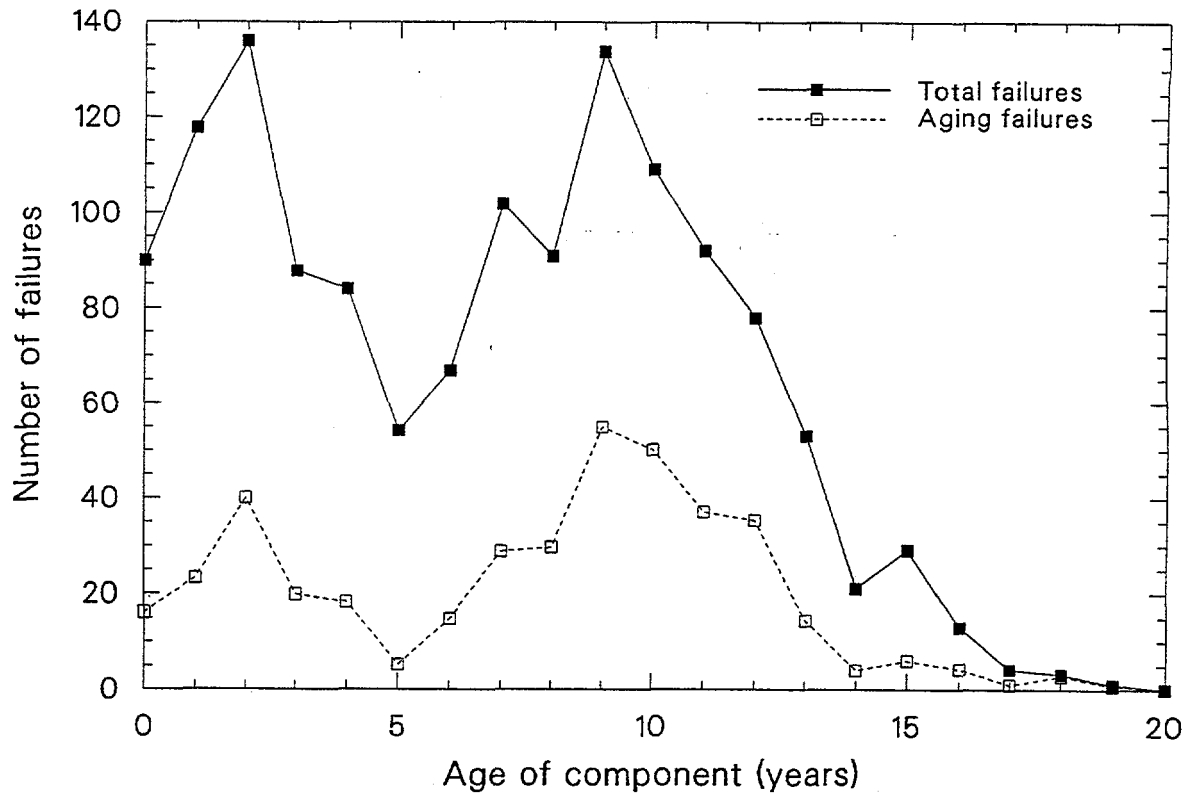


Figure 11. HPI system total and aging failures from NPRDS data.

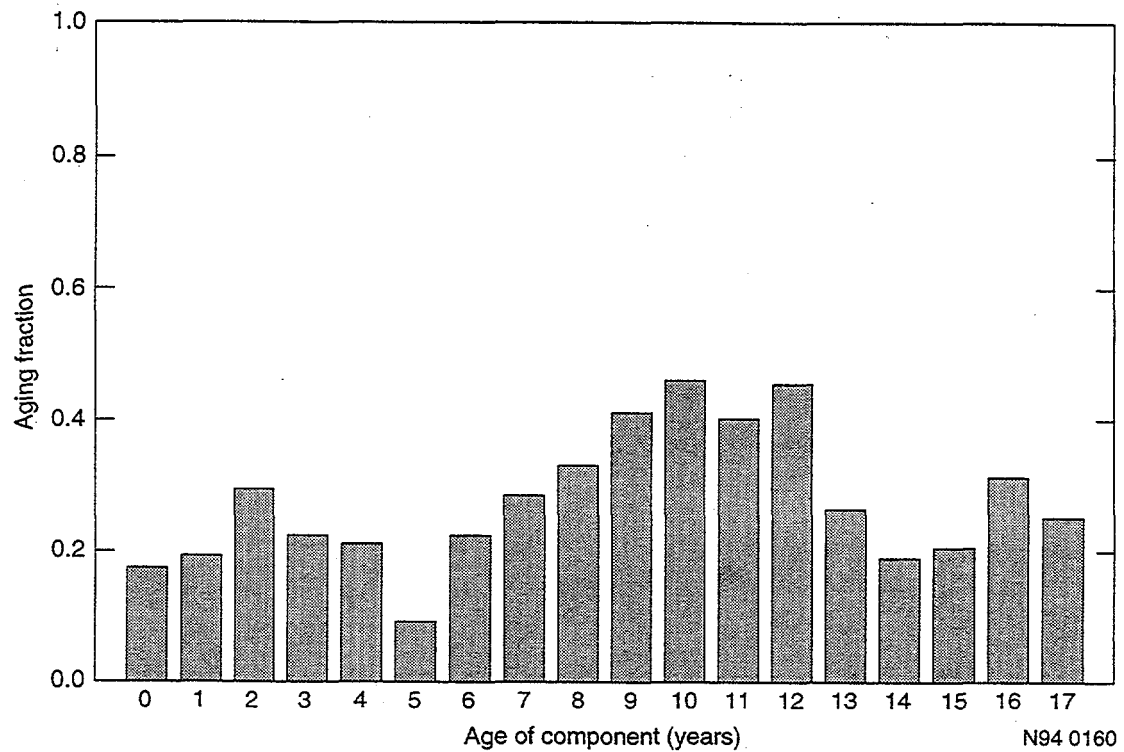


Figure 12. HPI system aging fractions from NPRDS data.

decreasing trend in the number of aging failures for components 10 years or older as shown in Figure 11.

The component aging fractions for six commonly failed components are presented in Table 25 in 5-year increments through component ages of 15 years. The components showing the most significant aging trends are valves and switches. Piping supports, HPCI turbines, and valve operators also show aging trends, particularly in the first two time increments. This indicates that aging degradation is also occurring in these components and that they are typically being repaired or replaced after approximately 11 years of service. The components operating longer than 11 years present too small of a sample for reliable aging fraction trending. Component age plotted against aging fractions are shown in Figures 13 and 14 for HPI system switches and valves, respectively. The first 10 years of component age show an increasing trend in aging fraction. The number of failures drops off significantly after age 13 for switches, and after age 12 for valves; therefore, this region does not represent a good statistical sample. The valve aging fraction, shown in Figure 14, is of particular interest because overall it is significantly higher than the aging fraction of other components, indicating that aging degradation is more prevalent in valves than other HPI components.

Figure 15 shows the number of BWR plants for each plant age from the operating license date through 1989, when the NPRDS data were collected. The number of plants peaks at age 15, but is approximately constant at other ages. The number of plants that can contribute component failures of a certain age must be considered when assessing failures of components of specific ages. For example, there is a small number of failures for most components at age 16 because few plants are 16 years old or older.

4.7 Summary of Data Analysis

When considering normalization of the failure data, it is clear that valves are the most numerous component in the system and, therefore, would be expected to be the component with the most failures. The typical number of each of the active component types included in the inservice inspection boundary is listed in Table 26. It is interesting to note that there are numerous instruments and switches in the HPI systems, and they are ranked in the top four failing components by three of the databases. The HPCI turbine was identified by three of the databases as a moderate contributor to failures, but it is a single HPCI component. However, some of the failures of pumps and instrumentation and control components may actually have been turbine, turbine governor, or other turbine operation and control failures.

Table 25. Component aging fractions in 5-year increments from NPRDS data.

Component	Aging fraction		
	0-5 years	6-10 years	11-15 years
Valves	0.43	0.60	0.61
Switches	0.06	0.11	0.26
Instruments	0.17	0.16	0.23
Pipe supports	0.23	0.54	0.17
Turbine	0.11	0.19	0.10
Valve operators	0.20	0.25	0.18

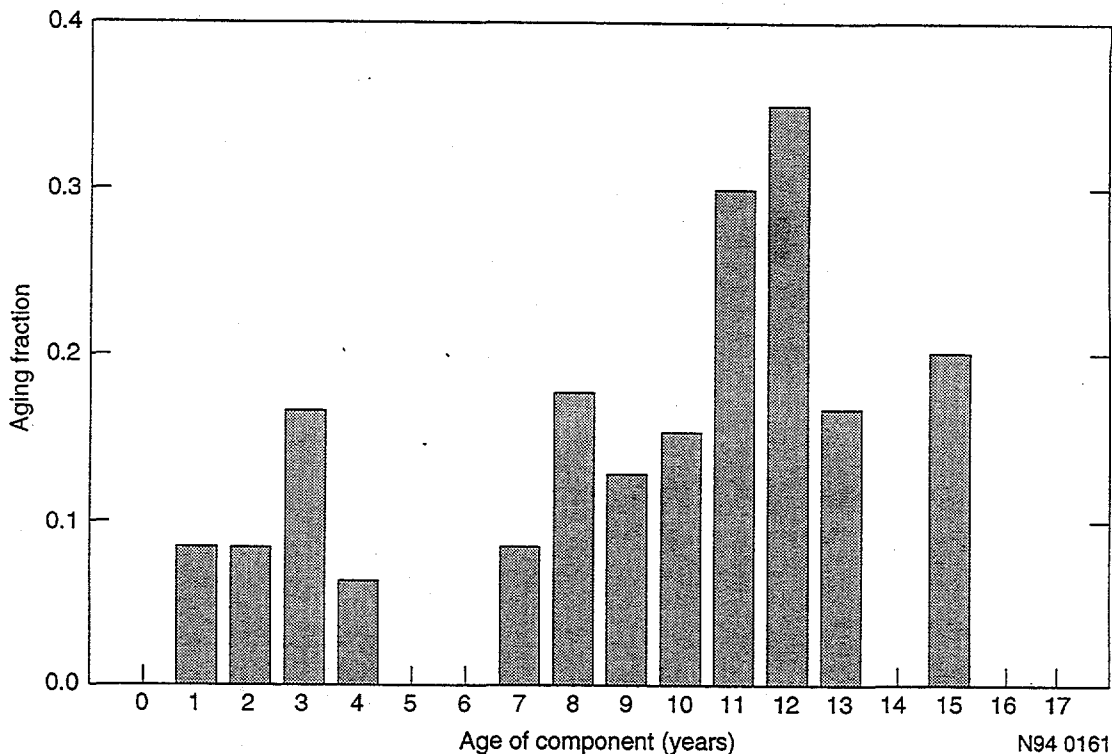


Figure 13. HPI system switch aging fractions from NPRDS aging data.

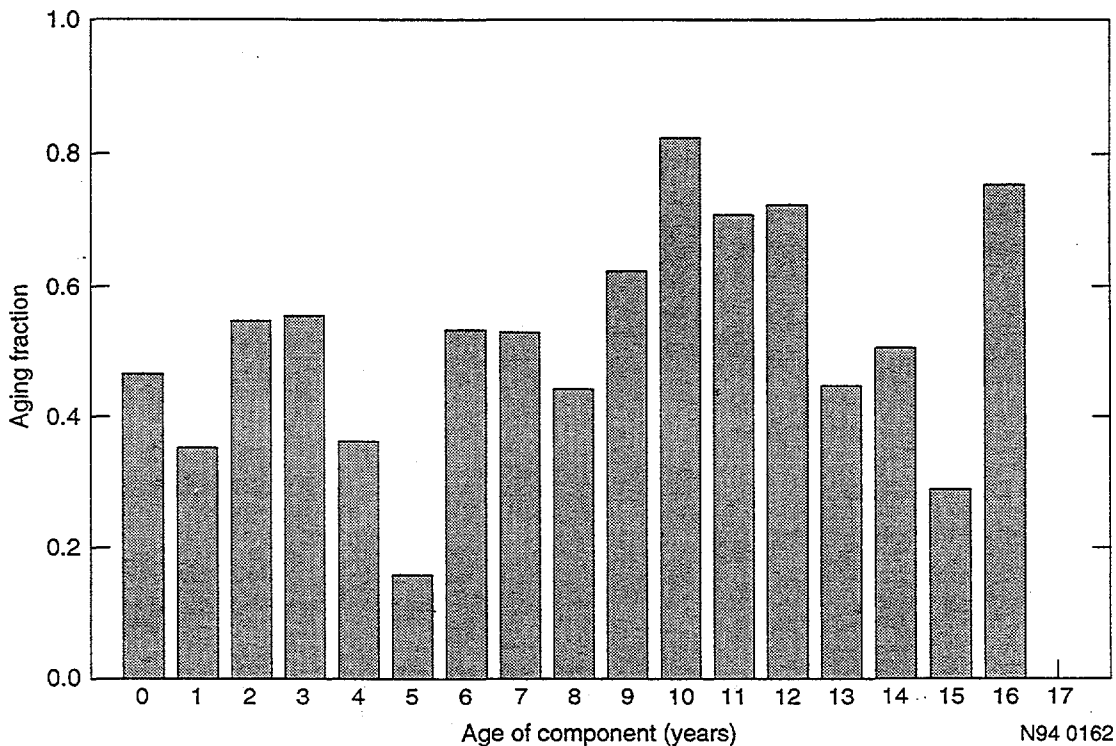


Figure 14. HPI system valve aging fractions from NPRDS aging data.

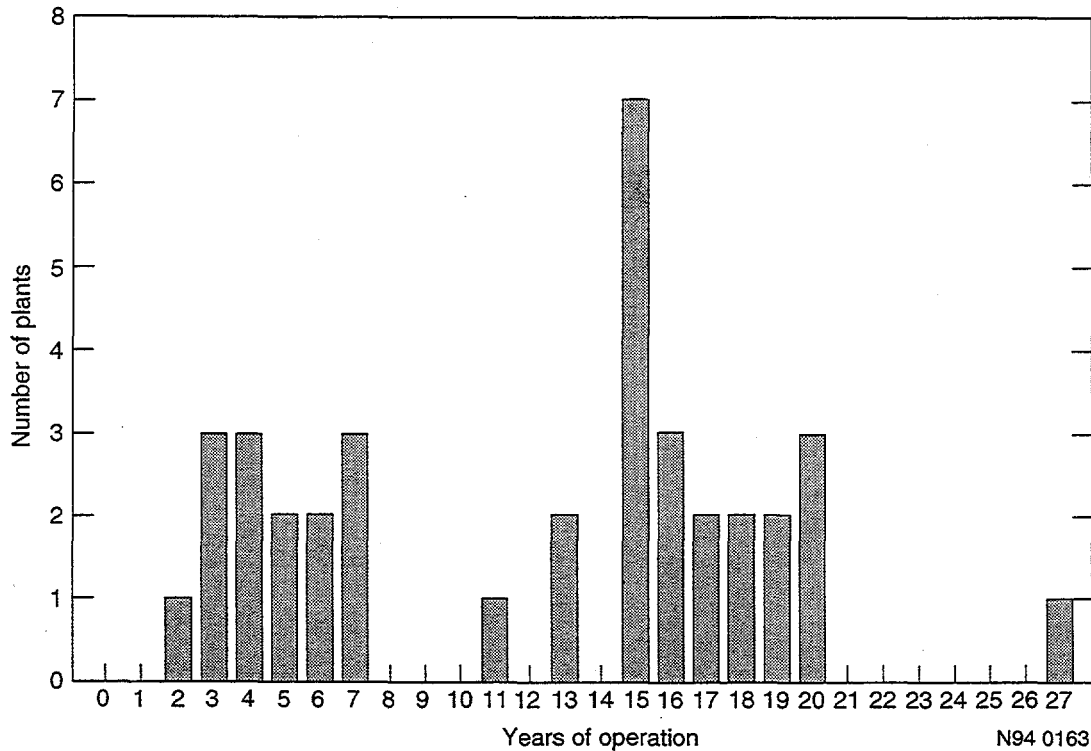


Figure 15. Age of BWR plants from operating license date through 1989.

Table 26. Typical number of each component type in HPI systems included in the inservice inspection boundary.

Component	Number
Valves	35
Instruments	21
Switches	15
Pumps	3
Rupture discs	2
Turbine (HPCI only)	1
Gland seal leak-off condenser	1

Note: There is also a significant amount of piping, pipe supports, and snubbers, but information to quantify these was not available.

There is a variation among the top components in the different databases because of varying reporting requirements between databases and varying reporting requirements over time. Table 27 shows the ranking of the seven components that were the most consistently failing components across all of the databases. Clearly, valves and valve operators are the HPI components with the most failures in three of the databases. They are only exceeded by instrumentation and control component failures in NPRDS. Wear is the leading failure cause identified for both valves and valve operators, and a significant portion of valve wear failures reported in NPRDS data are packing leaks. A major contributor to this wear is valve friction under high loads. Further research into the tribological aspects of valve friction could be performed to better characterize valve and valve operator wear.

Table 28 summarizes the dominant failure modes, aging failure causes, and detection

Table 27. Ranking of consistently failing components by database.

Component	NPE	LER	NPRDS	Plant-specific
Valves	1	1	2	1 ^a
Valve operators	3	3	3	1 ^a
Instrumentation and control	2	—	1	4
Pumps	9	2	—	2 ^a
Turbine	11	4	5	2 ^a
Pipe	6	5	—	—
Pipe supports	—	9	4	3

a. Plant-specific data do not differentiate between valve and valve operator failures or between turbine and pump failures.

Table 28. Summary of dominant failure modes, aging failure causes, and detection methods identified by database analyses.

Component	Failure mode	Failure cause	Detection
Valves	Degraded operation 27.7%	Wear 26.4%	Surveillance testing 45.0%
Valve operators	Degraded operation 29.1%	Wear 9.3%	Surveillance testing 43.7%
Instrumentation and control	Loss of function 49.6%	Corrosion 19.4% Dirt 13.9	Surveillance testing 42.1%
Pumps	Low injection flow 74.3%	Wear 33.3% Improper lubrication 31.1%	Surveillance testing 43.2%
Turbine	Degraded operation 35.6%	Improper lubrication 27.7% Improper maintenance 13.8% Wear 12.9% Dirt 6.5% Fatigue 4.6%	Surveillance testing 54.2%
Pipe	Leakage 44.2%	Corrosion 36.9% Time-related material degradation 18.2% Fatigue 14.3% Misalignment 14.3% Dirt 13.4%	Surveillance testing 45.5%
Pipe supports	Failure to operate 36.4%	Time-related material degradation 16.2%	Surveillance testing 51.5%

methods from the database analyses for the components in Table 27. Figure 16 summarizes the total failure causes for the HPI system in graphical form. Clearly, a significant number of these failure causes fit into the definition of aging given in NUREG-1144 (see Reference 1). Even though surveillance and testing are the most common methods of detecting failures in these components, they detect only about 50% of the failures that occur; therefore, it is clear that surveillance and monitoring methods can be improved to detect more failures before they cause a system failure. Also, research has shown that many HPCI failures can be eliminated by implementing improved preventive maintenance programs.³⁰

A large number of failures typically caused by wear, corrosion, dirt, improper maintenance, improper lubrication, fatigue, misalignment, setpoint drift, or out-of-calibration instrumentation caused the HPI system to be inoperable. Each of these failure causes are age-related or may act in conjunction with other problems to contribute to aging degradation.

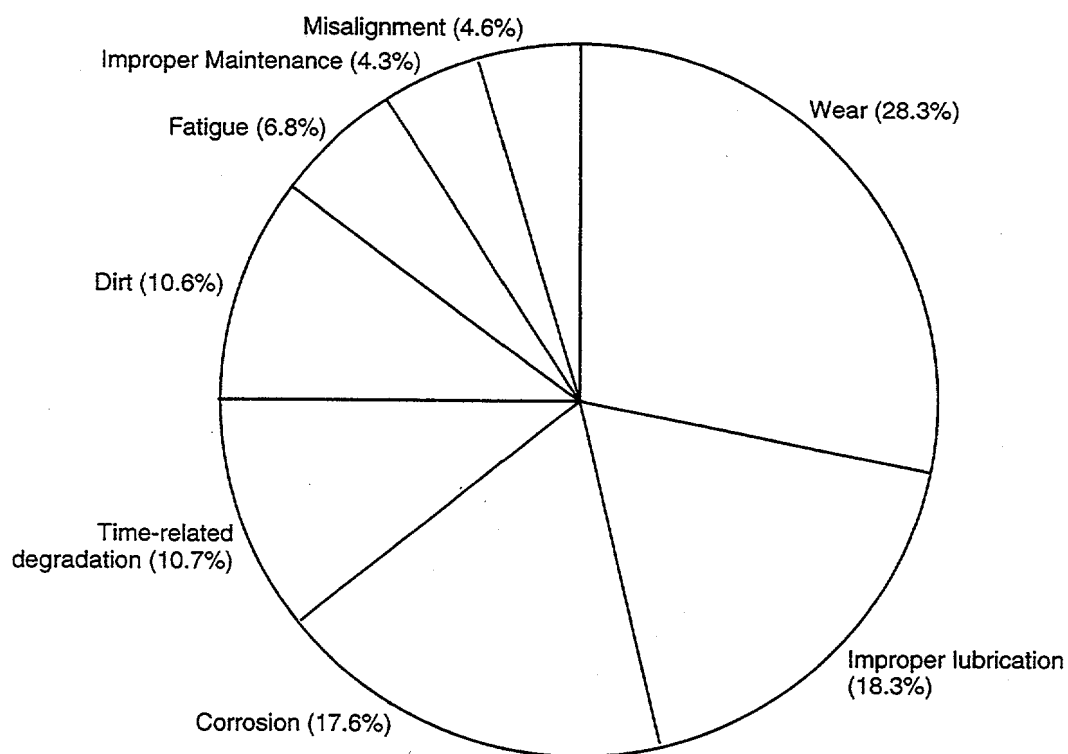
Most of these failures were detected during testing, but operational abnormalities, maintenance, and routine observations also detected some failures. An improved surveillance and monitoring program would also help to reduce the number of testing and operating failures by identifying more problems before failures occur.

The only significant difference between HPCI and HPCS failure records was the higher number of instrumentation failures in the HPCS system and the related instrument failure causes such as

setpoint drift and out-of-calibration. This is partially related to the design of some HPCS systems that include more instrumentation, such as keep-full systems for lines susceptible to voiding and the lack of a steam turbine and the related turbine components.

One issue that may be of major importance is the variation in operating hours from plant to plant because certain aging degradation mechanisms occur only when a component is operating, such as wear in a valve. Since the HPI systems are standby systems, the hours of operation are low but may vary widely; therefore, the aging degradation rate may vary widely from plant to plant.

The overall conclusion to be made from the examined failure experiences is that aging degradation is occurring in the HPI systems, and some of these failures are causing the HPI system to be inoperable while others are causing degraded system reliability or degraded operation. Another important conclusion is that only a small number of incipient failures are being detected before causing a testing failure or an operational abnormality. This indicates that surveillance and monitoring programs could be improved to increase the rate of incipient failures detected. Research and development of methods to mitigate aging degradation and reduce the failure frequency, together with the implementation of recommendations from vendors and completed research, can make these systems more reliable. Specific failures and related safety issues are presented in Section 5. These are areas of concern for which additional research for HPI improvement should be focused.



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Figure 16. Summary of HPI failure causes from NPE, NPRDS, LERs, and plant-specific data.

5. REVIEW OF SAFETY ISSUES FOR HPI SYSTEMS

The safety issues described in this section were identified, during the aging study, to be of particular importance for HPI systems. These issues have been identified by the NRC, EPRI, and the nuclear power industry as safety issues that require resolution. Research is being done to resolve them. Aging degradation is a contributor to these issues, and aging studies may contribute to the resolution of these safety issues.

5.1 HPI System Valves

The tendency of most maintenance programs is to do whatever is required to put a valve motor operator back into service rather than to determine the failure cause. For example, a torque switch adjustment is made to deliver increased valve operating force, and little effort is applied to determining the source of the increased drag force that will eventually cause failure of the valve or valve operator motor. Torque switches are involved in nearly 25% of corrective actions; however, experience suggests that they are providing an indication that a problem exists rather than showing the cause of the problem.

An NPAR study on MOVs identified the lack of compatibility between valves and their attached motor operator as the root cause of the majority of MOV failures (see Reference 26). Reference 26 identifies the typical valve failure modes as bent valve stem, cracked seat or disc, damaged valve body, or failure to operate. Some fast-actuating valve operators are oversized by design, and the resulting loads may damage the valve, particularly when torque switch settings are high and the valve is operated at a low load condition. Proposed solutions include proper sizing of the overload protection devices and the motor operator to the valve, improved procedures for setting the overload protection devices, improved preventive and corrective maintenance programs, improved training of maintenance personnel, and better communication with the valve and valve operator manufacturers.

Several bent and broken stems were discovered on the turbine steam supply and pump injection MOVs at Dresden Units 2 and 3 from 1973 to 1977.³¹ The cause of the failures was determined to be oversized motors on the valve operators. These valves are required to be rapid-operation valves, and this demands a high speed operator that may, in combination with the operator inertia, overtorque the valve when closing it and exceed the stem's compression yield point. Another contributing factor was found to be excessive cycling during surveillance testing. The recommended repair procedure was to install motors that were 60–75% of the size of standard motors and to lower gear ratios to reduce the torque. The smaller operators provided slower operation, but were capable of opening the valves with the "hammer blow" effect feature, providing the force necessary to overcome the torque applied when closing.

Another MOV operator motor problem was identified at several plants in the 1980s when failures occurred because of the short duty cycle rating of the motors.³² During operation, testing, and maintenance, the valves were sometimes cycled excessively, which caused insulation degradation and eventually failure. Three or four consecutive cycles is the maximum rate before overheating occurs, and some valves are cycled eight or more times in short periods of time. This problem was identified as a generic problem with most MOVs in the HPCI system, and the recommended repair was to replace the motors with longer duty cycle models.

As a result of the accident at Three Mile Island Unit 2 in 1979, the NRC developed an action plan to resolve the generic safety issues that were identified. One of these issues, Task II.E.6, In Situ Testing of Valves, was to evaluate requirements for valve testing to ensure performance under design conditions.³³ The action plan includes a survey of current requirements and practices for design, specification, and qualification of safety-related valves. Also, recommendations for improved methods of verifying performance requirements will be a result of this research.

Review of Safety Issues for HPI Systems

Resolution of this issue is continuing through NRC Bulletin 85-03 on failures caused by improper torque and limit switch settings,³⁴ Generic Issue 87 on evaluating the design and operability of BWR containment isolation valves,³⁵ and Generic Letter 89-10 on improved methods for testing and surveillance of safety related MOVs.³⁶

The HPCI steam supply line has two containment isolation valves in series—one inside and one outside of containment. Both are normally open in most plants. The operation of the valves is tested periodically without steam. Only the opening characteristics are tested by the valve manufacturer because of their facility limitations. Therefore, the capability of the valves to close when exposed to the forces created by the flow from a downstream break has not been demonstrated (see Reference 33). The INEL is performing a gate valve flow interruption research program to provide a technical basis for resolving Generic Issue Number 87, Failure of HPCI Steam Line Without Isolation, which includes concerns about uncertainties in gate valve operator sizing and torque switch settings (see Reference 35). The results of this work show that the values of some of the parameters in typical equations used for valve operator sizing do not conservatively estimate the total thrust required to close valves under high-energy pipe-break conditions.

Intergranular stress corrosion cracking failures of valve stems that were made out of type 410 stainless steel have occurred in four plants, including Brunswick 2 and Browns Ferry 3.³⁷ The tempering of type 410 stainless steel may leave the material with poor corrosion resistance while the cooling process results in high internal stresses. The slowly growing cracks were initiated in areas where corrosive chemicals had concentrated, such as the gland packing. These cracks were not detected by operability testing, but were discovered by disassembly or failures. Failure of this type in HPI system valves would prevent the HPI system from performing its function.

Type 410 stainless steel has also been a problem in bolts on the lifting beam in the turbine

throttle valve at the J. A. FitzPatrick plant.³⁸ The bolts were found broken, and the cause was determined to be intergranular stress corrosion cracking. The material was found to be too hard, indicating improper heat treatment, and the stress was caused by the initial torque preload. The NRC is requiring all licensees to review the design of safety-related check valves to determine which valves may contain susceptible materials and then to inspect these check valves. A review of all the valves in the HPI systems would identify where susceptible materials are used; then, the identified susceptible components could be inspected for cracks and tested for hardness.

Failures of swing arms in certain service water system check valves have been identified as problems at Comanche Peak Unit 1.³⁹ High back-leakage led to the discovery of a disc separated from a 14-4PH, alloy swing arm in a bolted bonnet swing check valve. Evaluation of the failure included fractography, chemical analysis, and metallography. The causes of the failure were determined to be fabrication defects, high residual stresses, porosity, inadequate heat treatment, and weld repairs. The failure mechanisms were fabrication defects propagated by residual stresses and normal operating conditions. Similar valves inspected for these defects showed a 19% rejection rate. Swing arm check valves in BWR HPI systems could be inspected for similar problems.

Backseating of valves to prevent leakage around the stem has led to valve failures.⁴⁰ Backseating involves using the valve's motor operator to drive the valve disc against the backseat with a force great enough to open the open torque switch. These stresses occur each time the valve is opened and may remain until the valve is closed again. This results in high-strain, low-cycle failures such as valve stem breaking, valve stem elongation, backseat damage, or stem nut cracking. Some plants routinely backseat valves, but electrically backseating valves on torque is not a generally recommended practice.

The aged gate valve testing program that was conducted by the INEL has identified improper power cable sizing as a cause of dc MOVs failing

to fully seat.⁴¹ Cable sized according to the operator nameplate data will not carry the current that must be developed during locked rotor conditions. The locked rotor current is more than five times the nameplate full load current. Improper cable sizing contributed to the failure of the HPCI turbine steam supply valve to open during post-maintenance testing at the Brunswick Unit 1 nuclear plant.⁴²

The INEL valve testing program also identified a problem with Limitorque SMA-type motor operators in NRC Information Notice 89-43.⁴³ The torque switch helical springs in two 30-year-old valve operators being tested had developed significant permanent deformation. This deformation reduced the overall length of the spring and the amount of preload on the spring to less than expected values, which caused the torque switch to open at reduced torque. Tripping the torque switch at reduced torque values may cause the operator to stop before fully closing the valve.

Lower available output torque is a significant concern for Limitorque SMA-type operators on safety-related valves. A valve operator with a deformed spring may not accomplish its intended safety function because the torque switch has not been adjusted to compensate for the deformation. The torque switch spring is in its most compressed position when the valve is closed. Therefore, normally closed valves are most likely to experience permanent torque spring deformation.

The BWR Owners Group is beginning a project to address valve body erosion caused by cavitation, which is induced by valve throttling.⁴⁴ As many as 16 valves in a plant have been identified as being susceptible to erosion. These valves include one to three test return line valves in HPI systems depending on the HPCI/HPCS system type and layout. This same mechanism may also be a concern in piping and pumps. The BWR Owners Group program, presented to NRC staff in 1989, includes the following procedures: survey utilities to identify all safety-related valves used for throttling, request data on cavitation erosion, identify methods used to eliminate

erosion, and prepare a guidance report on the program results.

During the process of complying with NRC Generic Letter 85-03 pertaining to the reliability of MOVs during design basis events, a number of deficiencies, misadjustments, and degraded conditions in MOVs were identified by nuclear plant licensees and are presented in Table 29 (see Reference 34). Many of these mechanisms have been identified as significant aging failure causes in the database analysis presented in Section 4 and in the specific concerns described in this section. In addition, Generic Letter 89-10 concluded that unless additional testing for ASME Section XI requirements is performed on safety-related MOVs and position-changeable MOVs, they will fail to operate more often than previously estimated (see Reference 36).

Three events have taken place in PWR ECCSs that were caused by back-leakage of hot water through closed valves.⁴⁵ In these events, thermal stratification of the water in the piping and fluctuations of the interface between the hot and cold streams of water led to cracking of the piping wall in the heat-affected zones of welds and in the base metal (see Reference 8). The PWR piping configuration between the reactor coolant piping and the first check valve in the ECCS is similar to the configuration in BWRs, and valve back-leakage is not an uncommon occurrence in valves.

In 1987 at Brunswick Unit 2, a reactor scram occurred on low reactor vessel coolant level caused by loss of uninterruptible power to the feedwater pump control system.⁴⁶ The HPCI system was initiated and did perform as required. However, following the scram recovery, the HPCI system was found to be inoperable because of a failed motor on the pump discharge valve. When the HPCI injection terminated on high vessel coolant level, a momentary reverse flow path existed from the feedwater line to the CST, allowing feedwater at approximately 204°C (400°F) to cause local flashing in the CST until the injection valve closed. Reverse flow caused thermal binding of the pump discharge valve, which caused the motor to burn out when the valve closed at termination of the injection. This problem can be

Table 29. Summary of common MOV failure mechanisms.

-
- * Incorrect torque switch bypass settings
 - * Incorrect torque switch settings
 - Unbalanced torque switch
 - * Spring pack gap or incorrect spring pack preload
 - Incorrect stem packing tightness
 - Excessive inertia
 - Loose or tight stem-nut locknut
 - * Incorrect limit switch settings
 - * Stem wear
 - * Bent or broken stem
 - * Worn or broken gears
 - * Grease problems (hardening, migration into spring pack, lack of grease, excessive grease, contamination, non-specified grease)
 - Motor insulation or rotor degradation
 - * Incorrect wire size or degraded wiring
 - * Disc/seal binding (includes thermal binding)
 - Water in internal parts
 - * Motor undersized (for degraded voltage conditions or other conditions)
 - Incorrect valve position indication
 - Misadjustment or failure of handwheel declutch mechanism
 - * Relay problems (incorrect, dirty, deteriorated, or miswired relays)
 - Incorrect thermal overload switch settings
 - Worn or broken bearings
 - Broken or cracked limit switch and torque switch components
 - Missing or modified torque switch limiter plate
 - * Improperly sized actuators
 - Hydraulic lockup
 - Incorrect metallic materials for gears, keys, bolts, shafts, etc.
 - Degraded voltage (within design basis)
 - Defective motor control logic
 - * Excessive seating or backseating force application
 - Incorrect reassembly or adjustment after maintenance and/or testing
 - Unauthorized modifications or adjustments
 - Torque switch or limit switch binding

* Significant aging failure mechanism or safety issue.

prevented by modifying the system to switch to recirculation mode, as described in Section 5.2, rather than shutting down when coolant level is recovered.

HPCI turbine exhaust check valve failures have been identified as a generic concern.⁴⁷ The disc in the same valve type in a similar system has fractured in several plants, and this same failure

may occur in the HPCI system also. The causes of these failures are improper system operation, improper check valve sizing, or inadequate check valve or exhaust line design. To alleviate this problem, Reference 47 recommended that system operation below the recommended turbine rated speed be minimized and that the turbine exhaust check valve internals be visually

inspected on a routine basis, such as every refueling outage.

5.2 HPI System Reliability

According to Reference 30, HPI system reliability has improved in recent years, and the current trend is for HPI failure rates (based on LERs) to be decreasing. However, many BWR plants, while meeting technical specification requirements, are not meeting the performance goals established for the HPI system by the nuclear steam supply vendor. While the number of HPI failures varies widely from plant to plant, there has been a number of cases in recent years when the HPI system would not operate on demand. Reference 30 also indicated that about 80% of the plants are doing cold, quick-start tests of the HPI system. Because not all plants are performing cold, quick-start tests, the number of reported failures may be artificially low because prewarming the system may prevent failures that would occur during a cold start. Because cold, quick-start testing has been determined to be the only test that ensures that the whole system will function correctly during an automatic-initiation signal, Reference 30 endorsed increased adoption of this type of testing. However, the required frequency for testing should be set so as to maximize system reliability and minimize system stress.

A group of LERs were analyzed, and 30 events that resulted in a failure to inject water into the reactor vessel after an automatic-initiation signal were identified (see Reference 30). The causes of these events were:

- Oil supply—dirty filter
 - High turbine exhaust pressure—water in steam inlet line
 - Steam line pressure differential—cause unknown
 - Turbine governor control system—various reasons
 - Inboard isolation valve—packing leak, unknown
 - High exhaust diaphragm pressure—inner diaphragm failed
 - Gland seal condenser—leaking gasket.
- High steam line pressure differential caused the HPCI system at Hatch Unit 1 to isolate immediately after an automatic-initiation signal was received, and manual manipulation was then necessary to start the system.⁴⁸ Another automatic HPCI system isolation occurred on high steam-line flow at FitzPatrick Nuclear Power Plant in November 1989.⁴⁹ A series of tests were performed to determine the root cause of this isolation. The results showed that turbine startup differential pressure signal sometimes exceeds the isolation setpoint when no high flow condition is occurring and no setpoint drift has occurred. The typical isolation setpoint value used to indicate a break in the steamline is 300% of the rated steam flow. The tests at the FitzPatrick plant found that the value calculated for isolation actually corresponded to approximately 200% of rated steam flow. Adjusting the setpoint to actually correspond to 300% rated flow restored HPCI system reliability. Implementing a time delay on turbine-inlet-line high-steam-flow isolation logic could reduce the frequency of this event. In addition, a time delay could reduce spurious isolations caused by pressure transients and setpoint drifts, which are a significant concern because they occur often, reducing the reliability of the system to inject on demand.⁵⁰
- Some of the other events above could also have been prevented by improved maintenance

- Mechanical overspeed—cause unknown
- Turbine inlet control valve—motor winding failure
- Injection line MOV—motor failure
- Stop valve—water in hydraulic operating oil, piston ring wear
- Controller—cause unknown
- Electric governor magnetic pickup control box—out of calibration

programs or equipment redesigns. Reliability has been found to be strongly influenced by plant operations and maintenance practices, and a correlation has been established between preventive maintenance practices and low MOV failure rates.

In a 1989 report by the NRC Office for Analysis and Evaluation of Operational Data, covering 22 BWR plants, on-demand malfunctions of the HPCI system were analyzed.⁵¹ The most frequent operational transient that demands a response from the HPCI system was determined to be a loss of main feedwater flow to the reactor core. This transient is expected to occur an average of twice per year per plant. A less frequent operational transient is post-scrum reactor depressurization. From 1976 to 1988, there were 59 failure-to-inject events with 26 failures occurring from 1979 to 1981. Of the 59 failures, 39 occurred at the four units of two nuclear plant sites. The on-demand failure frequency appears to be decreasing, and this may be because of operating experience gained from previous failures. The majority of the failures occurring at four units indicates that reliability is strongly dependent on individual plant

practices. As noted in Section 4.4 of this report, this indicates that plants should review their programs that affect HPI system reliability to determine the need to improve these programs and to learn from plants with low failure rates.

Another study was performed for the HPCI systems at the Browns Ferry plants.⁵² The goal of this study was to assess the operational history of the HPCI systems with respect to (a) system reliability and availability, (b) recurring problems affecting system performance or reliability at each unit, and (c) the Browns Ferry HPCI systems' performance as compared to HPCI systems at other BWR plants. The system reliability was found to be increasing, but several problems such as failures of the turbine governor and suppression pool/CST switches have not been adequately addressed yet. These problems are not unique to the plant but are generic problems. The long-term nature of the remaining recurring problems may require a more aggressive monitoring and maintenance program to determine the root causes involved and the required corrective actions. A list of the recurrent problems identified is presented in Table 30. Valve, turbine, and

Table 30. Recurrent problems in the Browns Ferry HPCI systems.

Problem	Events
Turbine governor problems	18
Valve problems	13
Failure of turbine exhaust inner rupture diaphragms	10
Blown inverter fuse	8
Leaking gland seal condenser gaskets	8
Level transfer switches failing	7
Set point drift	5
Water hammer	4
Auxiliary lube oil pump malfunction	4

instrumentation problems are near the top of the list, as expected, when compared to the results of the data analysis presented in Section 4. A comparison of the Browns Ferry HPCI system unavailability for each year with the mean value of 1.3% for all BWRs indicates that the Browns Ferry units are comparable to the rest of the nuclear industry.

At the Vermont Yankee plant in 1984, a transient occurred that caused a sealed-in trip of the HPCI system on high vessel water level.⁵³ During restart, an operator observed that the turbine throttle valve had not opened as expected. It was then discovered that the high water level trip signal was still sealed in, locking out the HPCI system. This problem could have been prevented by modifying the system such that when it has been verified that water level has recovered, the HPCI system would be placed in the recirculation to the CST mode. The HPCI system would then be left running and available for immediate return to full service without requiring another startup challenge. The high-water-level turbine-trip signal must still remain to prevent entrainment of liquid water with the steam, which would damage the turbine.

A list of recommendations to improve HPCI reliability is included in Reference 30. Three of those recommendations that address concerns described in this section are the following: (a) a comprehensive preventive maintenance program needs to be carried out, such as the detailed example included in Reference 30, Appendix G; (b) surveillance testing should include a cold quick-start of the HPCI system and a visual examination of the system during testing; however, no prewarming should be done; and (c) the opening and closing cycle and motor currents for all MOVs should be tested following maintenance and before declaring the valve ready for service.

5.3 HPI System Testing

The full stroke time for power-operated valves is normally measured to verify operability and to detect valve degradation. In Generic Letter 89-04,

the NRC has identified limitations with stroke time as a measure of operational readiness of a valve. The ASME Code requires establishment of a limiting value on full stroke time for each valve.⁵⁴ The purpose for the limiting value on full stroke time is to establish a threshold for taking corrective action on a degraded valve before the valve reaches the point of a highly probable failure. Comparing measured stroke times to a reference value as opposed to comparing measurements to the previous test is the recommended alternative.⁵⁵ A reference value for comparison could be developed by averaging stroke times determined from a series of stroke time tests performed when proper valve operation has been verified. Variations in measured stroke times can be significant for dc-powered MOVs and can indicate valve performance degradation. However, comparing measurements to a reference value varies from the Code requirements, so this deviation could be made a part of the in-service testing program. In addition, valve stroke testing provides valve exercise and some assurance of operational reliability (see Reference 36). Another concern expressed by the NRC is that stroke time testing may result in unnecessary accumulated wear to valve seats.⁵⁶

An NRC staff evaluation indicates that unless additional measures are taken, failure of safety-related MOVs to operate under design-basis conditions will occur much more often than previously estimated (see Reference 36). They conclude that ASME Code Section XI testing alone is not sufficient to provide assurance of MOV operability under design-basis conditions. The NRC recommends that valve testing programs include all safety-related MOVs and all MOVs in safety-related systems capable of being mispositioned. It recommends that the programs include testing, inspection, and maintenance of these MOVs to provide the necessary assurance that the valves will function when subjected to the design-basis conditions. When establishing the design-basis conditions, the NRC recommends consideration of normal operation, abnormal events, and recovery from mispositioning. In addition, it recommends that torque and limit switch settings be evaluated to ensure that they are correctly

determined and that they are set and maintained to compensate for the effects of wear and aging.

During an EPRI research project, operations and maintenance personnel at Hatch Unit 2 were asked to identify concerns regarding HPCI system testing.⁵⁷ The concerns identified were:

- Testing that causes inadvertent reactor trips
- Testing that promotes premature equipment failure (such as diesel generator, MOVs, and ECCS pump motors)
- Testing that creates problems that must be dealt with afterwards (such as pool level increase and pool temperature increase)
- Testing that increases personnel exposure
- Testing that wears out electrical contacts, which must be replaced or serviced.

Whenever testing interferes with the functioning of a component, the effect on overall plant risk is also a consideration. Probabilistic risk assessments may be useful to ensure that the plant will remain in a safe condition (see Reference 56). Many current testing programs are limited because they do not address problems from a systems point of view, but rather focus on individual components such as pumps and valves in isolation from the rest of the plant. Some recommendations proposed to reduce these concerns are described in Reference 57 and include modifications to allow out-of-service time periods and surveillance test intervals.

Testing of relay contacts is another area of concern for nuclear plants. During an inspection of the HPCI system at the Duane Arnold plant, it was discovered that certain relay contacts were not being tested.⁵⁸ This is significant because failure of these relays could result in the HPCI system being inoperable. An improved testing program was initiated to ensure that these contacts are verified to be operable as intended.

5.4 Water Hammer in HPI Systems

Out of a group of 81 water hammer events that occurred in BWR plants, 18 caused a safety system to be inoperable (see Reference 25). Two of these events were caused by water hammer in a non-safety system, resulting in flooding that caused a safety system to be inoperable. The HPCI system accounted for 20 of these events, more than any other BWR system except residual heat removal. The HPCI water hammer events were attributed to four causes:

- Steam-water entrainment (12 events), which occurred in turbine inlet lines, caused by improper isolation valve usage and drain pot malfunctions; in turbine exhaust line, caused by drain level switch malfunction; and in gland seal leak-off condenser inlet line, caused by operator error
- Steam-bubble collapse (4 events), which were caused by vacuum occurring in turbine exhaust lines
- Flow into voided line (3 events), which occurred in pump discharge lines
- Unknown (1 event), which occurred in pump discharge lines.

The consequences of these events have involved both equipment damage and system inoperability and are considered to have a high safety significance. The potential for similar events to occur in BWR plants with a HPCS system exists, but the jockey pump and the lack of a turbine greatly reduce the chances of water hammer occurring. The analysis of these events indicates that good design features and operational procedures can minimize the occurrence of water hammer. Plant design, layout, and normal operating and maintenance practices also influence the occurrence of water hammer.

Design features that are currently used in HPCI systems to prevent water and steam hammer include drain pots with testable drain pot level switches, sloped lines, limitations on opening and

closing sequences and seal-ins for manual operation of the isolation valves, and vacuum breakers in the turbine exhaust lines.

Undetected water hammer events occurred at Dresden Unit 3, which were caused by a leaking valve.⁵⁹ (Also see Reference 45.) Back-leakage of feedwater through the injection valve (see Figure 5) had been occurring for eight months when, in October 1989, the licensee concluded that some of the leakage was flashing in the piping and displacing some of the water with steam. Steam in the piping is a precursor to a water hammer event when system initiation occurs. Back-leakage through the injection valve is normally prevented by the testable check valve, but this valve leaked because of "service-induced wear." Increased leakage through both valves was detected by temperature monitors showing higher temperatures (275°F) in the line between the injection valve and the pump discharge valve. Accessible portions of the HPCI piping were inspected, and loose pipe supports and damage to concrete surfaces were found. This damage was probably a result of water hammers occurring during pump tests and valve operations. To correct the problem, the licensee has repaired the damage and installed a monitoring program to detect back-leakage.

Several recommendations have been made in existing studies that will reduce the incidence of HPCI system water hammers when they are adequately implemented.⁶⁰ These recommendations include the following: (a) replace the seal-in feature of the turbine steam supply containment isolation valves, which causes them to immediately open fully, with a gradual opening capability; (b) develop opening sequence operating procedures and provide operator training to prevent steam-water entrainment caused by improper containment isolation valve operation; (c) provide proper drain pot sizing, level verification equipment, and operating procedures to prevent steam-water entrainment caused by drain pot malfunctions; (d) require the drain pot system to be checked for operability on a regular schedule; (e) install keep-full, void detection, and venting systems together with operator training and

operating procedures to prevent discharge to voided lines; and (f) provide the turbine exhaust line with vacuum breakers.

5.5 Instrumentation and Electrical Issues

The water level instrumentation in a BWR is relied on for actuating the HPI system and for providing operators the information to be used as a basis for actions to ensure adequate core cooling. Plant operating experience shows that even with the redundancy in some systems, failures do occur. Three potential improvement categories have been identified by the NRC staff.⁶¹ The first area for improvement is the reduction of level indication errors caused by reference leg overheating. The overheating is caused by high drywell temperatures that contribute to the aging degradation of wiring, instrumentation, and electrical components. The second area is the improvement of reliability by installing analog level transmitters to replace mechanical level indication equipment. Plant experience shows that mechanical equipment is more susceptible to failure or malfunction than analog equipment. The third category includes changes to system logic in plants in which operator action may be required to mitigate the consequences of a break in one reference leg, occurring with a single failure in a protection system channel associated with another intact reference leg. The installation of additional transmitters will satisfy the single failure criterion.

A turbine trip on overspeed occurred during testing at the Cooper plant in 1985.⁶² The cause of the trip was determined to be an error in the electrical connections between the governor control and the governor-valve electric-governor-remote hydraulic actuator, causing the valve to fail while fully open. This failure is of particular importance because it would not be detected by a rated flow test to the CST at a reactor pressure of 1.0 MPa (150 psig). A procedure change was made to discover similar failures in the future that required the operator to adjust the flow controller setpoint to decrease flow by 1,900 L/min (500 gpm) and to verify pump runback and flow stability. This will functionally test the entire flow

control and governor subsystem. Similar procedure changes could be implemented at plants wherever applicable.

5.6 HPCI Turbine Issues

Using uncontaminated lubricating oil containing corrosion inhibitor for the HPCI turbine is very important because improper lubricating oil can cause aging degradation.⁶³ An event in which a turbine failed to reach rated speed was reported at the Cooper plant, and the cause was a failed electric-governor-remote actuator in the turbine governor. The actuator failed because of water and rust buildup in the actuator housing. The water was introduced through the lube oil system. It was found that incorrect oil, without corrosion inhibitor, was being used in the lube oil system at the time of the incident. Water-contaminated lubricating oil caused an HPCI automatic-initiation failure at Hatch Unit 2 because hydraulic pressure was insufficient to open the turbine stop valve.⁶⁴ A routine sampling of the turbine oil system was initiated to prevent recurrence of the contaminated oil problem. Lubricating oil selection, as the Cooper event points out, must be as specified in the vendor's turbine technical manual to prevent aging degradation. The Hatch event emphasizes the importance of a good maintenance program to ensure proper operation. Although these events are relatively old, they are included in this report to emphasize the importance of paying attention to these items to prevent aging.

Rust and scale buildup were also determined to be the cause of bent turbine control valve lift rods at the Cooper plant.⁶⁵ The corrosion product buildup in the steam chest of the control valve caused the lift rods to seize up and bend. General Electric (GE) recommends regular examination of the control valve for rust and binding and replacement of any damaged parts. In addition, GE recommends the installation of a linkage modification that will reduce the bending moment on the lift rods during valve operation.

During inspections at Peach Bottom Units 2 and 3, broken cap screws and missing clamping plates that secure the turbine reversing chambers were

discovered.⁶⁶ The American Society for Testing and Materials A574 socket head cap screws were determined to have failed from fatigue fractures. The Terry Steam Turbine Company, through GE, recommended elimination of the clamping plates and use of different cap screws. Information from the Terry Steam Turbine Company indicates that similar turbines were supplied for HPCI systems at 19 other BWR plants.

5.7 HPI Pump Issues

In 1989 at Dresden Unit 2, leakage through an HPCI injection valve was found to be flashing and displacing water in the injection line with steam (see Reference 45). A significant concern in this event is the potential for steam binding to cause failure of the HPCI pump because the pump discharge valve is normally open. Similar events have occurred in PWRs that have resulted in steam binding of auxiliary feedwater pumps. Because of these events, the NRC staff required that certain licensees monitor the pump discharge temperature to ensure that it remains below saturation temperature and to identify steam binding if it does occur. This requirement may be applicable to BWR HPI pumps.

Lubricating oil contamination with water has occurred in HPCI pumps similar to the turbine events described previously.⁶⁷ At Quad Cities Unit 1, during monthly HPCI pump operability surveillance, the pump oil was found contaminated with water. The water contamination was identified by the color of the lubricating oil. The HPCI system was declared inoperable although it was still capable of performing its intended function. The water contamination was caused by a leak in the pump's oil cooler system that allowed water to seep into the lubricating oil. The leakage was repaired by replacing the worn out pump oil cooler O-rings and gaskets.

Events at the Brunswick and Peach Bottom plants have identified a concern about minimum flow line valves and HPI pumps.⁶⁸ The importance of minimum flow line systems may not be fully recognized or reflected in their design and operation. Pump and turbine damage can occur in as little as 30 seconds of operating against

shutoff head. Shutoff head is the pressure in the pump outlet line that the pump can no longer operate against. Operation against shutoff head can occur if a minimum flow valve is unexpectedly closed and the pump cannot overcome reactor coolant system pressure. Recommendations from Reference 68 to prevent this problem include modifying procedures to prevent deactivating minimum flow valves when system operability is required, and modifying the operation logic to ensure that the valve is open before the pump starts and to allow closure when the pumps are not running.

5.8 Maintenance Rework

Errors like the improper reassembly of components are the most common causes of required correction of previous maintenance.⁶⁹ A review of 84 rework cases reported in Licensee Event Reports from 1986 to 1988 showed the following results:

- Improper component assembly or miswiring: 38%
- Improper diagnosis of failure root cause: 25%
- Improvisations by maintenance personnel: 8%
- Procedural, administrative, or vendor problems: 29%.

Most of these maintenance errors were identified and corrected through normal channels such as testing, inspection, and post-maintenance checkout. Most rework events involve only one component, and the safety significance of these errors appears to be low. However, improvisations by maintenance personnel may be of significant concern because they could lead to more serious consequences that are not identified or tested through normal channels.

5.9 System Initiations

The number of HPI initiations per year varies from plant to plant depending on several factors

such as the age and design of the plant and the effectiveness of the testing and maintenance programs. One plant experienced 22 system initiations (an exceptionally high number) in the first year of operation, and all of these were inadvertent initiations. The safety concern related to HPI system initiations is the potential for exceeding the number of initiations included in the system design. HPI systems have been designed assuming six initiations per year for a lifetime of 40 years. Design analysis accounts for corrosion, erosion, and fatigue (see Reference 22). In the analysis, it was determined that during injection, the thermal cycles are insignificant and the pressure cycles are the primary stressor causing fatigue damage. The total fatigue usage factor is predicted to be the highest in the HPCS feedwater line connection or the HPCS injection nozzle. However, this total fatigue usage factor is predicted to be less than 0.2 at the end of 40 years. Table 31 shows the average number of HPI system initiations for required and inadvertent demands. As can be seen, the total number of initiations per plant year from 1985 to 1989 is well below the design allowable of six initiations per year. During this time period, 104 of the system initiations occurred simultaneously with a reactor trip. Twenty of these initiations were inadvertent, and the leading causes of the inadvertent initiations were instrumentation and control component failures, faulty mechanical equipment, and improper maintenance actions. Clearly, this supports the research results in Section 4.7, which shows instrumentation and control components as being among the top four failing component categories in each of the databases.

The total number of initiations should continue to be monitored and compared to the design basis for determining the remaining fatigue life of the components, such as the injection nozzles, for current safety analysis, and for future aging degradation considerations. The monitored initiations should include required starts, inadvertent starts, cold-start testing, and prewarmed testing starts. However, because of the relatively low usage factor, this fatigue damage is not expected to be a life-limiting factor for plants.

Table 31. BWR HPI system initiations from 1985 to 1989 LER data.

	1985	1986	1987	1988	1989
Operating plants	33	37	37	37	38
All initiations per plant	1.7	1.6	1.3	1.0	0.8
Required initiations per plant	0.8	0.4	0.8	0.4	0.2
Inadvertent initiations per plant	0.8	1.2	0.5	0.6	0.6

6. TESTING, INSPECTION, SURVEILLANCE, AND MAINTENANCE

An important part of this aging study is a review of the testing, inspection, surveillance, and maintenance methods currently being applied to detect and mitigate aging failures and degradation. These practices are primarily described in technical specifications and plant-specific documentation.

6.1 Technical Specification Requirements

The purpose of technical specifications is to address the requirements of 10 CFR 50 (see Section 9.1) covering definitions, safety limits, limiting safety system settings, limiting conditions for operation, surveillance requirements, design features, and administrative controls (see Reference 18). A summary of the important technical specification testing requirements for verifying operability of the HPCI system is presented in Table 32. A description of the requirements to be met when the system is inoperable is presented in the following paragraphs.^{70,71}

The HPCI actuation instrumentation includes the level and pressure instruments that provide the electrical signals that cause automatic system operation as described in Section 2.2.9. This instrumentation shall be operable with the required setpoints identified in the technical specifications actuation instrumentation setpoints table. With an actuation instrumentation channel setpoint that is less conservative than required, the channel must be declared inoperable. Inoperable channels must be restored to operable status within the required time, or the HPCI system must be declared inoperable.

The HPCI system is required to be operable with one injection pump and a flow path capable of taking suction from the suppression chamber and injecting the water into the reactor vessel. The HPCI system is not required to be operable when the reactor steam dome pressure is less than or equal to 0.7 MPa (100 psig). When the HPCI system is inoperable, a limiting condition for operation is declared, and the system must be

restored to operable status within 14 days, or the plant must be in at least hot shutdown within the next 12 hours and the reactor steam dome pressure must be reduced to less than 1.0 MPa (150 psig) within the following 24 hours.

Another requirement is that the HPCI system response time must be less than or equal to 30 seconds. The response time is the time interval from the initiation signal on low-low reactor vessel water level until the system is capable of injecting water into the vessel. A recent GE and EPRI research program has shown that the safety analyses used to determine ECCS requirements may be overly conservative and that these requirements can be reduced while maintaining a substantial core safety margin (see Reference 7). A recommendation is made in that report to consider relaxing the response time requirements for the HPCI system to less than or equal to 60 seconds. The benefits of this modification would be a reduced turbine speed-up rate, reduced testing, and fewer outages as a result of less restrictive technical specification requirements. Reducing the turbine speed-up rate will reduce wear and, therefore, aging degradation of the HPCI components.

The only significant difference between the technical specifications for HPCI plants and those for HPCS plants is the system response time. The required HPCS response time is less than or equal to 27 seconds. This time must also include diesel generator starting and sequence loading delays.

For the individual plant that was selected for this aging study, the HPCI system technical specification testing section included some specific testing requirements. These include pump and MOV operability tests monthly, flow rate testing at 7.0 MPa (1,000 psig) every 3 months, and flow rate testing at 1.0 MPa (150 psig) every operating cycle.

None of the technical specification requirements are specifically focused on detecting or monitoring aging degradation. Technical

Table 32. Summary of technical specification testing requirements for verifying operability of HPI systems.

Equipment	Frequency	Requirement
Actuation instrumentation	Monthly	Surveillance testing and calibration Discharge line keep-full alarm Reactor vessel water level High drywell pressure CST level low Suppression pool water level high Reactor vessel water level high Pump discharge pressure high (HPCS only) HPCS system flow rate low Division 3 bus power monitor (HPCS only)
	Every 18 months	Logic system functional test
HPI system	Monthly	Verify correct position for injection pump flow controller Verify that system piping from pump discharge valve to system isolation valve is filled with water Verify that each flow path valve is in correct position and not locked in position
	Every 18 months	Complete system functional test Verify development of 5,600-gpm flow against test line pressure corresponding to reactor pressure of >215 psig Verify suction is automatically transferred from CST to suppression pool on low CST level or high suppression pool level signals Perform channel calibration of discharge line keep-full alarm

specification requirements generally ensure only the operability of a system and consider only the degradation that is currently affecting operability. Except for some instrumentation, technical specifications control systems and not components. However, through required technical specification activities, many component aging degradation mechanisms and incipient failures are identified before they cause the system to be inoperable.

6.2 ASME Code Section XI Requirements

ASME Boiler and Pressure Vessel Code Section XI specifies testing requirements for components in safety-related systems, which includes HPI systems (see Reference 54). Section XI defines the inservice testing requirements for nuclear plants, unless a relief has been granted by the NRC. The applicable inservice testing for HPI

systems primarily includes pumps, valves, and welds. Pumps are tested quarterly for vibration, differential pressure, and flow rates. Valves are tested quarterly for stroke time, typically without differential pressure. The stroke time measurements are usually made with a stopwatch. Measurement of electrical characteristics is not required for pumps or valves; however, many plants are using electrical diagnostic equipment on MOVs to resolve NRC Bulletin 85-03 and Generic Letter 89-10 (see References 34 and 36). Because this equipment has not been in use long, and testing is not yet being repeated or verified consistently, monitoring of aging degradation has not been verified. Some of the methods developed in response to NRC Bulletin 85-03 and Generic Letter 89-10 may meet this need.

Section XI requires a portion of the welds to be inspected volumetrically every 10 years. This is normally done with ultrasonic inspection techniques, but the techniques specified in Section XI proved to be inadequate for detecting the thermal fatigue cracks and base metal cracks found in two plants. The use of special techniques with higher instrument gain was necessary to detect the cracks.⁷² Improved techniques for volumetric inspection and base metal inspection for high stress regions are being developed and used. Work at EPRI⁷³ and the Program for the Inspection of Steel Components⁷⁴ was done to evaluate the capabilities and limitations of current and advanced ultrasonic flaw detection techniques.

6.3 Inservice Testing

The NRC requires that inservice testing be performed on valves and pumps that are important to safety. Therefore, each plant inservice testing program includes many components that are to be tested for operational readiness. Inservice testing programs are designed to meet the requirements of the Code of Federal Regulations, ASME Code Section XI, and the technical specifications (see Section 9). The program includes information on component-specific parameters such as size, type, and identification and testing details such as frequency and method. Any requests for relief from testing requirements are also included and must

be justified. In addition, the inservice testing program lists the safety position and maximum stroke time for the power-actuated valves. Because of the variety of plant types, components, and system configurations, inservice testing programs vary widely from plant to plant.

Testing requirements for the HPI pumps are included in the inservice testing program, but turbines are not specifically identified. However, the HPCI turbine and pump are considered as a unit for most testing practices. Turbine parameters such as lubrication, oil and casing temperatures, governor and control valve operability, and vibration levels are covered in plant-specific testing procedures.

Typical pump parameters measured during inservice testing include inlet pressure, differential pressure, flow, bearing temperatures, lubricant levels, pump speed, and maximum vibration displacement and velocity in three orthogonal directions. HPCS jockey pumps are not considered safety related; however, some plants test them to inservice testing requirements to ensure safety and reliability, as well as system protection. Valves are typically stroke-tested, position-verified, and leak-tested. HPCI turbines are typically tested for input/output performance levels, bearing temperatures, vibration, control system operation, and lubricating oil condition.

6.4 Maintenance

Maintenance activities, other than those that are done as part of the technical specifications or regulatory requirements, vary widely from plant to plant. These programs vary as to the degree of personnel training, documentation, and formal record keeping. The preventive and corrective maintenance programs vary widely from plant to plant. Also, the surveillance and monitoring programs at most plants could be improved to identify incipient failures and, particularly, aging degradation problems before they cause a system unavailability. Preventive maintenance programs could be improved to reduce the problems that sometimes follow maintenance activities. A list of factors included in a plant testing and maintenance program that generated a low LER rate for

HPCI inoperability includes the following (see Reference 30):

1. An aggressive and well-defined preventive maintenance program that includes testing immediately following maintenance
2. Well-trained and experienced maintenance personnel
3. A quality system that requires records on all maintenance of safety-related systems and components and verification of installation and changes in status following calibration
4. Contamination-free HPI room to improve ease and accuracy of maintenance and inspection procedures
5. Monthly cold, quick-start surveillance testing with visual inspection in the HPI room to monitor operating conditions
6. Inspection of the equipment room on every shift to check for leaks
7. Measurement of MOV current while cycling the valve following maintenance work on the valve or the operator.

Reference 30 notes an improving trend in BWR HPI system reliability over the last few years. The report notes that many factors are important in that improving trend. The authors note that this would include the improved preventive maintenance programs that have been initiated at many plants. However, Reference 30 states that continued improvement is needed and that implementing the practices stated above and other activities identified in that report may eliminate many HPI problems.

The programs currently used for preventive and corrective maintenance for HPI systems are only partially effective for detecting, monitoring, and controlling aging degradation. These maintenance programs may be made more effective by incorporating the most recent methods that address aging degradation issues and elements of

other programs that have been shown to result in low unavailabilities and low failure rates.

6.5 Plant-Specific Methods and Requirements

During the plant-specific data collection efforts, a number of procedures related to the HPCI system and HPCI components were collected. The procedures were then separated into four categories: calibration, testing, maintenance, and operation. The testing category included 25 procedures, while only two calibration, two maintenance, and three system operating procedures were identified. All of the procedures tended to be focused on meeting technical specification, ASME Code, and inservice testing program requirements and to use manufacturers recommendations for maintenance. All of the maintenance activities are recorded and tracked through the plant's maintenance request program and are available for some trending information and component histories. Testing and maintenance programs could be improved by including new and updated procedures, specifically for activities such as monitoring aging degradation, preventive maintenance, and calibration that incorporates the results of the most recent research and operating experiences available. These may include such items as wear monitoring, improved inspection techniques, and recommendations for troubleshooting, repairing, and trending the characteristics of valve operators.

6.5.1 Calibration. Calibration procedures cover the turbine governor control system and the instruments that monitor the flow rate of the injection pump during flow-rate testing. Calibration instructions are provided for use each time the equipment is repaired or replaced, or when a potential problem is indicated. The acceptance criteria for each procedure includes verification that the work was performed without unexplained discrepancies.

The procedure for turbine governor control system calibration covers checkout of the electric governor magnetic pickup control box, the ramp

generator and signal convertor module, and the electric-governor-remote hydraulic actuator, independently and in conjunction with each other. The procedure includes voltage and resistance measurements, calibration of the response to a sine wave input, adjustment of the ramp time, calibration of the tachometer system, and simulated operational checkouts.

The pump flow rate instrumentation calibration procedure describes current measurements, electrical contact cleaning, setpoint verification, and simulated operational and functionality checks.

6.5.2 Testing. The testing procedures cover instrumentation, system functionality, and pump and valve operability tests that are primarily designed to meet ASME Code and technical specification requirements. Each test includes performance without unexplained discrepancies as acceptance criteria and double verification that the system is returned to the normal standby mode.

The instrumentation procedures contain the necessary information for performing functional and calibration tests on the important instrumentation components. Each procedure sets up a signal simulating the input that actuates that component and measures and checks the response to the signal. The responses include the correct signals sent to displays and alarms, the correct valve alignment, and the proper system actions all occurring in the allowable times. The instrumentation testing procedures include:

- Steam line high flow isolation
- Steam line high temperature
- Steam line low pressure
- Suppression chamber water level
- CST water level
- Pump discharge monitors.

Other instrumentation that inputs information to the HPCI systems but is not directly included as HPCI system components is covered by testing procedures for other plant systems.

The HPCI functional tests demonstrate the system's ability to operate as required when demanded. These tests simulate a signal that requires system action, and then measures the output or action response and the time required for this response. These measurements either verify system functionality or identify functional failures, such as valve stroke time that is out of acceptable range, which require corrective action. These measurements may also be used for trending aging degradation, but changes are not typically closely monitored over time. The system action signals that are tested include simulated automatic actuation and flow-rate testing, over-speed trip testing, initiation and high water trip logic testing, and high water level trip reset testing. The logic tests check the logic system, initiating pressure switches, level switches, valves, and pumps. This combination of component tests ensures that the system will automatically actuate and function properly when demanded.

The pump and valve testing procedures describe the monthly and quarterly operability testing required by the plant inservice testing program, operability testing, leakage measurements, and periodic exercise tests that are to be performed. These procedures also include instructions for post-maintenance testing to verify operability of the component. The pump tests include the HPCI turbine and cover cold startup and time to full flow injection capability, including turbine startup and valve operation times. The full flow test line makes testing full flow capabilities a simple and straightforward process (see Figure 7). A full flow test also exercises the injection check valves and MOVs. The measured pump test parameters are speed, flow rate, discharge and suction pressures, vibration displacement and velocity, lubricant level, and lubrication oil cooler temperature. Valve operability tests are performed by timing the stroke time for full stroke operation with a stopwatch. Valve leakage tests measure the ability of a valve to seal against applied air pressure. If the pressure

loss is below a minimum rate, the valve leakage is within acceptable limits. Check valve procedures require either a simple exercising process or exercising with the operating force measured depending on the valve's function. The vacuum breaker check valves are exercised by flow testing and by verifying that they fully open. The keep-full and pump suction check valves are exercised, and the operating force is measured with a dynamometer. The required force determines if the valve operates acceptably or requires maintenance. The turbine stop valve is a hydraulically operated valve that requires periodic adjustment of the opening mechanism balance chamber pressure. The procedure for this valve recommends that it be checked and adjusted once per operating cycle.

6.5.3 Maintenance. The two maintenance procedures identified during the plant-specific data collection pertain to MOV operator overhaul and electrical checkout and adjustment. The plant maintenance activities are normally controlled through the maintenance request system described in Section 4.5, including corrective and preventive maintenance. A maintenance request form may specify the use of either or both of the MOV operator maintenance procedures to perform electrical checkout and adjustment and overhaul for certain types of Limitorque motor operators.

During electrical checkout and adjustment of the motor operator, the actions performed include motor insulation testing, limit switch and torque switch checkout and adjustment, MOV operability tests, and position limit stop adjustments. Motor insulation testing is used only to measure the insulation resistance for the windings of dc motors. The motor leads are removed at the motor control center to avoid faulty readings caused by meggering (measurement of insulation resistance) back through the control circuit to ground. Other measured or adjusted parameters include stroke time, motor running current, stem travel distances, and as-found and as-left torque switch and limit switch settings. The torque switch adjustment section warns against changing the torque switch settings arbitrarily or exceeding the maximum settings. Before making torque switch

adjustments, the procedure requires checking the packing gland and valve stem for binding and proper lubrication. After the checks and adjustments described above are made, diagnostic signature testing analysis testing (Motor-Operated Valve Analysis and Test System or similar) is performed, particularly for safety-related valves.

Overhauling a Limitorque motor operator is described in detail in the second maintenance procedure. The overhaul includes disassembly, inspection, replacement of worn or broken parts, and reassembly of an operator that has been removed from a valve. The items to be examined include lubrication, O-rings, gaskets, covers, set-screws, gears, limit and torque switches, contacts, terminal boards, seals, rotors, and cleanliness. The as-found and as-left conditions of each item are recorded during the overhaul process, and appropriate warnings are included for difficult or sensitive steps wherever appropriate. Upon completion of any work associated with the springpack, torque switch, or gearbox of a safety related MOV, diagnostic signature analysis testing is performed.

6.5.4 System Operation. Three of the HPCI system procedures provided detailed explanations for operating or understanding the HPCI system or some related components. The three procedures covered the following:

- System operations
- Reactor vessel level and internal pressure instrumentation
- Room area coolers.

The system operations procedure included instructions related to standby status, response to automatic initiation, shutdown from manual or automatic operation, manual operation, test mode operation, emergency operation, and abnormal operation. This procedure explains all the operating characteristics, initiation and shutdown signals, and isolation conditions.

The reactor vessel level and pressure instrumentation procedure includes the generation of and response to various initiation signals and the

limitations imposed if an instrumentation failure occurs. Each instrument is described according to its location, identification, function, operating range, normal level, and temperature limitations.

Operation of the HPCI room area cooling and ventilation system is described in detail. The HPCI room is in the reactor building where the turbine and associated components are located, and this room's environment must be regulated to maintain the components within their temperature operating limits. The procedure describes the components, operation, capacity, and limitations of the redundant room area cooling systems.

6.6 Summary of Testing, Inspection, Surveillance, and Maintenance Effectiveness

Testing of HPI systems has been very effective at detecting failures of components because the test cannot be completed until all components are functioning. However, surveillance and monitoring methods could be improved to detect incipient failures before they cause a system failure during testing or operation. Table 33 lists the common aging degradation mechanisms and commonly used methods that will detect this degradation.

Maintenance and testing are identified as the detection methods for many mechanisms. This does not imply that the testing and preventive maintenance programs require inspection for these mechanisms, but indicates that these mechanisms are sometimes identified during testing and maintenance activities. There are several aging degradation mechanisms that are not being detected and that are not currently covered by any methods intended to detect them. The methods currently used are intended to determine if functionality or some parameter that affects functionality has degraded to some predetermined limit and to initiate corrective action when the limit has been reached. The methods are not designed to identify less severe degradation, that is to identify incipient failures. The current methods could be improved or supplemented by other improved testing, inspection, surveillance, and maintenance methods to provide for identifying degradation that could lead to failure before the failure actually occurred. Improved surveillance and monitoring methods will help anticipate and reduce failures, but will not eliminate them. Even with the best possible surveillance and monitoring programs, aging degradation will not be perfectly predictable. Thus, testing, inspection, and monitoring programs will continue to be required for indicating actual component and system conditions.

Table 33. Aging degradation mechanisms and the methods used to detect them.

Component	Aging mechanisms	Detection method
Valves	Fatigue	None
	Wear	Maintenance
	Thermal degradation	Thermography
	Embrittlement	None
	Degraded lubricant	Maintenance, lubricant analysis
Valve operators	Thermal degradation	Thermography
	Fatigue	None
	Wear	Maintenance
	Degraded wiring	Maintenance, testing
	Shorting/grounding	Visual inspection
	Poor electrical contact	Visual inspection
	Corrosion	Maintenance
	Degraded lubricant	Maintenance, lubricant analysis
	Degraded hydraulic and pneumatic lines	Maintenance, testing
Instrumentation and control	Embrittlement	None
	Corrosion	Testing
	Wear	None
	Fatigue	None
	Pitting	Testing
	Arcing	Testing
	Loose connections	Testing
Pump	Fatigue	Vibration signature analysis
	Wear	ASME Section XI inservice testing, testing
	Erosion	ASME Section XI inservice testing, testing
Turbine	Wear	Maintenance
	Fatigue	Vibration signature analysis
	Degraded lubricant	Maintenance, lubricant analysis
	Thermal aging	Thermography
	Degraded wiring	Maintenance, testing
	Control system shorting/grounding	Visual inspection, testing
	Poor electrical contact in control system	Testing
Piping	Fatigue	ASME Section XI inservice testing; volumetric and surface examinations
Pipe supports	Water hammer	Testing
	Testing	Visual inspection
	Maintenance	Testing
	Vibration	None
	Dirt	Maintenance
	Temperature	Maintenance
	Radiation	None

7. COMPONENT FAILURES AFFECTING PLANT RISK

Several probabilistic risk assessment (PRA) documents were examined to determine which events and failures in the HPI system have the most influence in causing system unavailability, which significantly increases plant risk. The PRAs used for this task were for the Peach Bottom, Shoreham, and Grand Gulf nuclear plants.^{75,76,77} The important component failure descriptions for the HPCI system of Peach Bottom Unit 2 were also used; these were taken from an NPAR project

aimed at detecting and quantifying time-dependent trends in failure data.⁷⁸ The basic events and component failures considered significant were those taken from event sequences that cause a plant core damage frequency of 1.0E-8/year or greater. The significant events and component failures for the three plants are presented in Table 34, along with their mean unavailability. Unavailability is the fraction of time during which the component or system is

Table 34. Events and component failures that influence core damage frequency.

	Mean unavailability
Peach Bottom Unit 2 (HPCI)	
Turbine-driven pump fails to run	5.0E-2
Turbine-driven pump fails to start	3.0E-2
Turbine-driven pump out for maintenance	1.0E-2
MOV fails to open	3.0E-3
MOV out for maintenance	2.0E-4
Flow controller fails	1.3E-4
Check valve fails to open	1.0E-4
Manual suction valve from CST plugged	4.0E-5
Shoreham Nuclear Power Station (HPCI)	
Entire system down for maintenance	1.0E-2
Turbine-driven pump loss of function	4.5E-3
Turbine loss of function	4.5E-3
MOV failure to open	4.0E-3
Temperature element loss of function	2.6E-3
Manual switch operational or maintenance fault	2.5E-3
Human error operational or maintenance fault	2.0E-3
Pressure sensor loss of function	1.2E-3
Motor-driven pump loss of function	1.2E-3
Relay loss of function	1.1E-3
Grand Gulf Unit 1 (HPCS)	
MOV for pump injection containment isolation fails to open	3.0E-3
MOV for pump minimum flow fails to open	3.0E-3
MOV for suppression pool pump suction fails to open	3.0E-3
MOV for CST pump suction fails to close	3.0E-3
Pump fails to start	3.0E-3

Component Failures Affecting Plant Risk

not available to perform its intended function. This includes time during which the component or system is failed and time for which testing, maintenance, or repair work is being performed.

The PRAs for the Peach Bottom and Grand Gulf nuclear plants list important components ranked by their risk reduction importance measures. The risk reduction measure for a component is the difference between the risk calculated with the component's failure probability set at a best-estimate value minus the risk calculated with the component's failure probability set at zero. The risk reduction measure is an approximate

measure of the significance of the component to the total core melt frequency. A ranking of components by risk reduction level identifies those components that are most important for plant reliability. By comparing this information to component unavailability and failure data, one can identify the most consistently failing components that have the highest risk reduction levels. Figures 4, 5, 7, and 8 show the HPI system layouts that include the components considered here. Table 27 lists consistently failing components; Table 34 lists component unavailabilities; and Table 35 identifies the most risk-significant HPI

Table 35. Risk-significant HPI components.

	Risk reduction level
Peach Bottom Unit 2 (HPCI)	
Turbine-driven pump	3.1E-07
Turbine steam supply MOV	1.8E-08
Injection MOV	1.7E-08
Gland seal leak-off condenser and lube oil cooler water supply MOV	1.0E-09
Pump suction from suppression pool MOV	1.0E-09
Pump discharge MOV	1.0E-09
Pump suction from CST MOV	1.0E-09
Pump discharge flow turbine controller	6.3E-10
Air-operated testable check valve	5.0E-10
Turbine exhaust check valve	5.0E-10
Pump suction check valve	5.0E-10
Grand Gulf Unit 1 (HPCS)	
Minimum flow MOV	1.3E-08
Pump suction from suppression pool MOV	1.3E-08
Injection MOV	1.3E-08
Pump suction from CST MOV	9.9E-09
HPCS pump	9.9E-09
HPCS start logic unit	5.3E-09
Air-operated testable check valve	3.3E-10
Pump suction from suppression pool check valve	3.3E-10
Injection check valve	3.3E-10
Pump suction from CST check valve	3.3E-10
Pump suction from CST hand-operated valve	1.3E-10
Injection hand-operated valve	1.3E-10

components for Peach Bottom and Grand Gulf. The most risk-significant component in the HPCI system is the turbine-driven pump. Table 27 identifies the pump and turbine as numbers four and five on the list of consistently failing components. MOVs are the next most risk-significant components in the HPCI system and the most risk-significant components in the HPCS system. Valves and valve operators are the top two most consistently failing components.

Risk is affected by aging and the types and magnitudes of the stressors considered. Even though PRAs do not take aging into account when determining risk-significant components, the possibility does exist of aging in some components, which affects overall plant risk. However, this is not expected to be a significant factor for standby systems such as HPI because the aging degradation is occurring at a relatively slow rate. One NPAR study identified very few failures from the LER and NPRDS databases that were significant to plant risk (see Reference 78). No statistically significant evidence of increasing failure rates was identified in the three HPCI system events considered (HPCI check valve fails to open, HPCI MOV fails to open, and HPCI turbine-driven pump fails to start).

The one concern that may be significant for HPI systems is that as the system and components

age, the downtime for maintenance activities is expected to increase. The older the system or components, the more time the system is expected to be unavailable while maintenance is being performed and, therefore, unavailable to inject water if demanded. Downtime data were collected from the NPRDS database by selecting the number of failures and the hours of system unavailability caused by each failure for both the HPCI and HPCS systems. These data are summarized in Figures 17 through 20. The number of failures and the hours of downtime for corrective maintenance per failure in HPCI systems increase as the systems age. HPCS systems show a decrease in the number of failures and an increase in hours of downtime per failure as the systems age. The number of failures in HPCS systems decreases probably because of the operating and maintenance experience being learned with these relatively new systems. HPCS systems could be monitored to determine whether the decreasing trend continues or HPCS systems show increasing trends similar to those of HPCI systems when a comparable amount of experience has been collected. The increase in HPCI system unavailability with aging is not accounted for in most PRAs. Advanced methods are being developed, under the NRC NPAR program, to evaluate the effects of aging degradation on component and system unavailability and on overall plant risk.

Component Failures Affecting Plant Risk

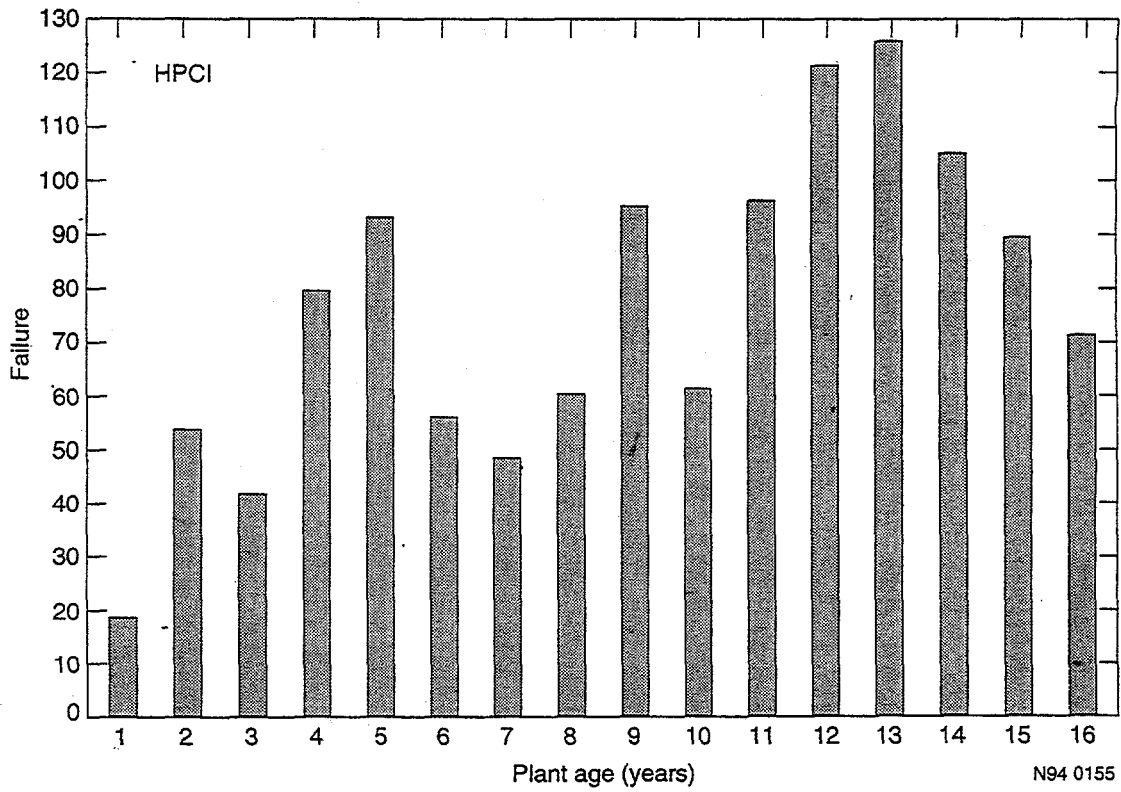


Figure 17. HPCI system failures causing system unavailability.

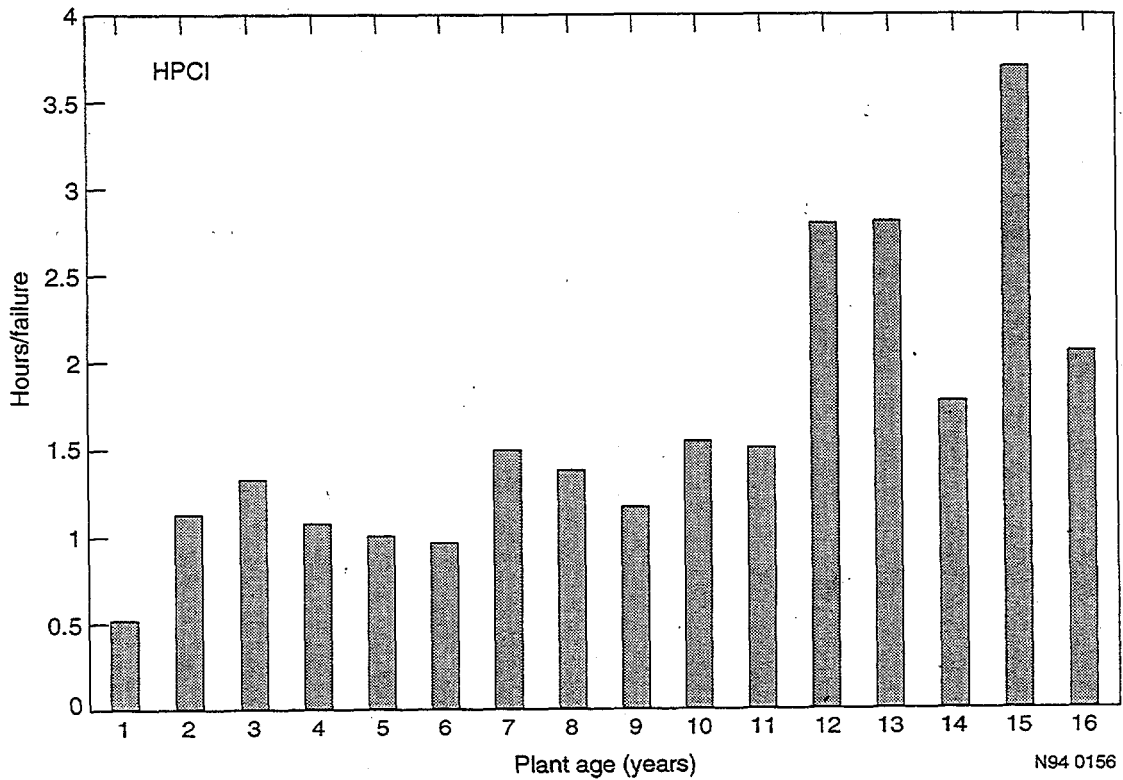


Figure 18. Hours of HPCI system unavailability for corrective maintenance per failure.

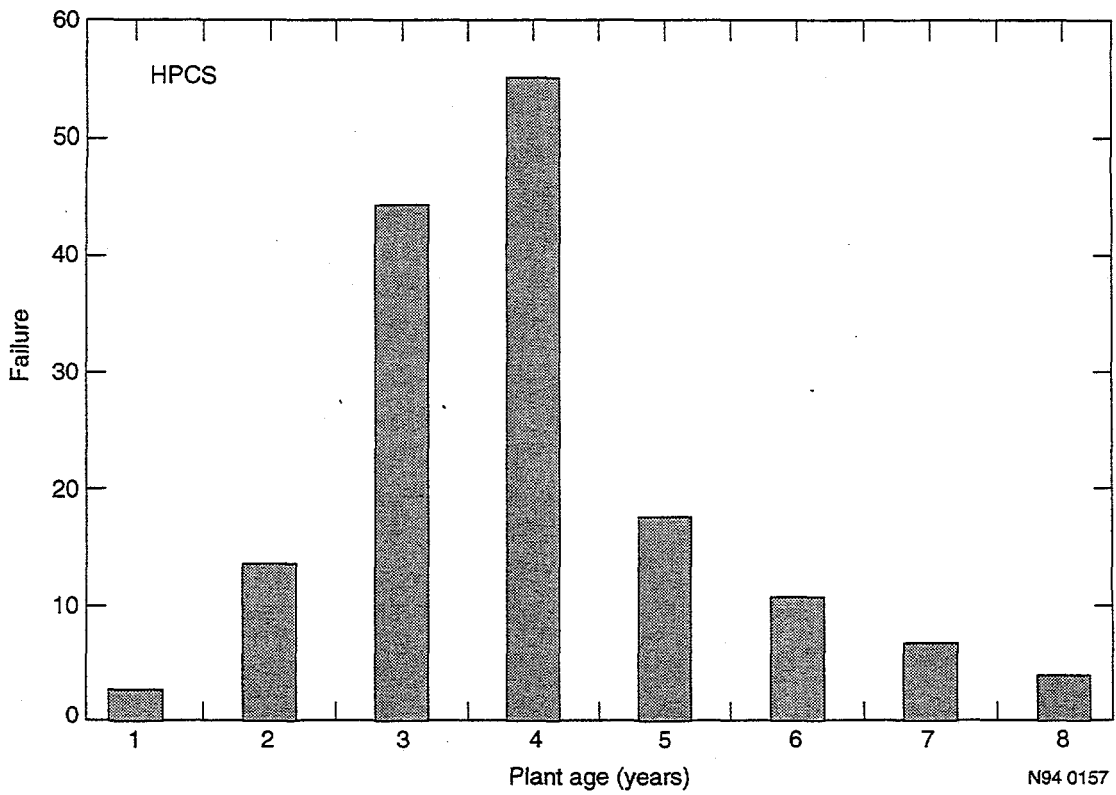


Figure 19. HPCS system failures causing system unavailability.

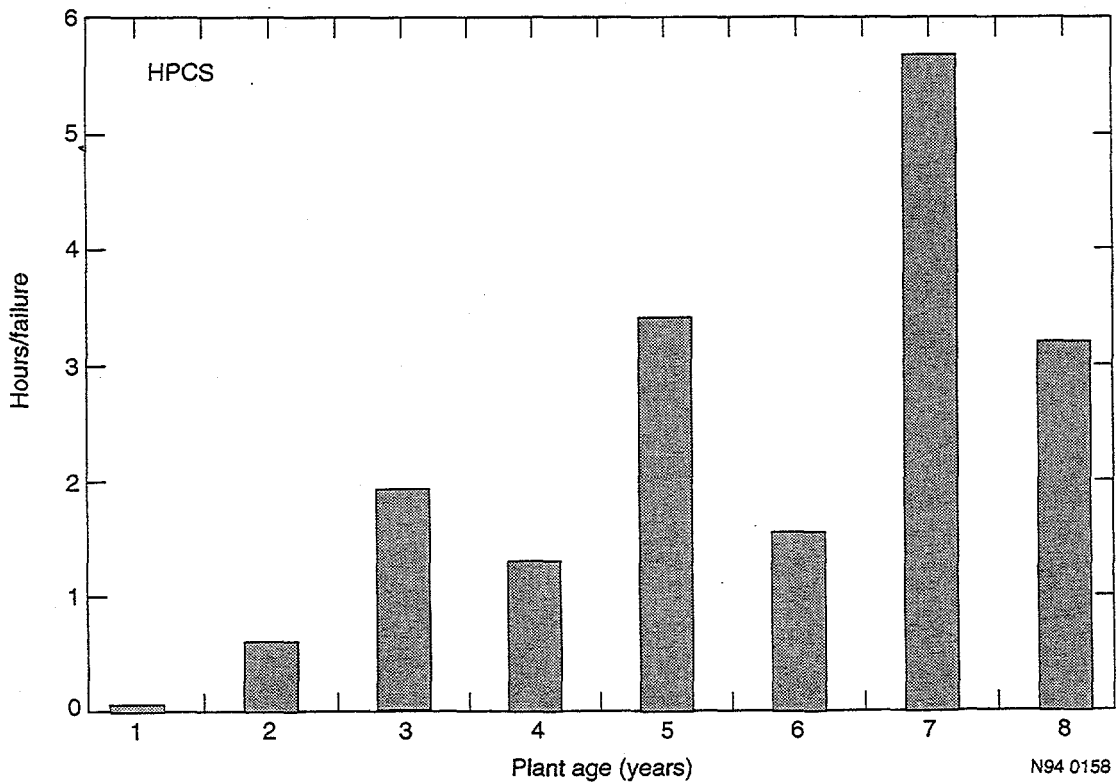


Figure 20. Hours of HPCS system unavailability for corrective maintenance per failure.

8. COMPARISON TO AGING REPORT ON THE REACTOR CORE ISOLATION COOLING SYSTEM

Brookhaven National Laboratory published an aging report on the RCIC system as part of the NPAR program.⁷⁹ There are similarities in design and function between the HPCI system examined in this report and the RCIC system examined in the Brookhaven report. In addition, the NPRDS and LER databases were used in both studies to analyze aging failures. These similarities allow the aging study results from the two systems to be compared where possible to determine any corresponding aging characteristics for the two systems.

The NPRDS and LER databases were analyzed for the system components having aging failures. The NPRDS database analyses show that the three top-ranked components in both the HPCI and the RCIC systems are the same: valves, switches/bistables, and valve operators. The next two components for the HPCI system are instrumentation (transmitter/primary/detector/element) and pipe supports. For the RCIC system, the next two components are circuit breakers and transmitters. Comparison of the analyses for the LER database shows similar results for the top five components with aging failures. For example, both the HPCI and the RCIC systems have valves, valve operators, and turbines in the top five, but rank them at different positions. The other top-ranked components in the HPCI system are pumps and miscellaneous subcomponents. For the RCIC system, they are switches/bistables and governors.

Information on component failures was also gathered by analyzing plant-specific maintenance records. Section 4.5 of this report presents plant-specific data from a BWR with more than 16 years operating experience. The RCIC study used maintenance records from a BWR with less than 10 years operating experience. Even though there are differences in age, and different systems were analyzed, the two studies found similar results. By a large margin, both studies found that the components with the most failures are valves and valve operators. For the HPCI system, the

other leading components are the turbine/pump, pipe supports, and instrumentation and control. For the RCIC study, the other top-ranked components are instrumentation and control and the turbine/pump. Therefore, the two systems show aging failures occurring in the same types of components and with similar component rankings with respect to number of component failures.

The NPRDS database contains information on failure detection, the component failure cause, and the effect of the failure on the system; the two studies evaluated these data for the HPCI and RCIC systems. Regarding failure detection, the top three failure detection methods for the two systems are the same: surveillance testing, routine observations, and operational abnormalities.

When evaluating failure causes, both studies performed the analysis by component, because of the different failure causes applicable to valves and instrumentation, for example. Two components that both studies ranked as failure causes were valves and valve operators. Wear, mechanical damage/binding, aging, and out of mechanical adjustment were the top four failure causes for valves in both studies. For valve operators, Section 4.4 of this report lists the four top-ranked failure causes in the HPCI system as wear, out of mechanical adjustment, burned out, and mechanical damage/binding. These causes, however, were closely grouped: the top four were separated by less than 5%. The RCIC study found the same top four valve operator failure causes, but the order was slightly different.

The effect on the system is recorded in the NPRDS database as no effect, loss of subsystem/channel, loss of redundancy, degraded system operation, or loss of system function. For the HPCI system, this study found the following ranking of system effects (from the most common to the least common): no effect, degraded system operation, loss of subsystem/channel, loss of system function, and loss of redundancy. The RCIC study found the ranking similar, with only the

order of the degraded system operation and loss of subsystem/channel reversed.

Component-age-at-failure trends were analyzed in both reports, also using NPRDS data. Similar results for the two systems were found when component age at failure was plotted versus number of failures. The HPCI system had peak component failures at 2 years and again at 9 years; peak component failures for the RCIC system occurred at 3 years and 12 years.

Section 7 of this report discusses the results of a PRA that was completed to identify the risk-significant components for the HPCI system. The RCIC study also completed a PRA. Direct comparison between the results of the two PRA studies is difficult because of the different methods used in them. However, some similarities between the two systems were found. The results documented in Section 7 of this report show that the main turbine-driven pump, MOVs, and check valves are the most risk-significant components. In the RCIC study, components or activities are grouped together to determine their group contribution to system unavailability. The most important groups are system instrumentation failures, maintenance unavailability, pump failures, and system MOV and pressure control valve failures. These results show that pumps and MOVs

are important to both systems in maintaining plant reliability.

Section 4.6 of this report notes that the aging fractions for some components increased with time, based on NPRDS data. This indicates that accelerated aging was occurring for these components: valves, switches, and instruments. The RCIC report did not analyze aging fractions in the same way. It analyzed aging fractions at the system level, and it used the LER database to perform the analysis. As a result, a direct comparison between the two reports is not meaningful. However, the RCIC analysis shows that aging failures were an increasing fraction of the LERs reported with time. Therefore, both reports show, though in different ways, that accelerated aging is a concern for each system.

In summary, the HPCI and RCIC systems show many similar aging characteristics. Aging failures in both systems were found in valves, valve operators, turbines, and switches/bistables. Using NPRDS data, the studies found that the failure detection methods, failure causes, and system effects are very similar. Although different methods were used, the PRA studies found that pumps and MOVs are important to both systems in maintaining plant reliability. Finally, both reports show in different ways that accelerated aging is a concern for each system.

9. CODES AND STANDARDS

The one thing in common with most of the codes and standards is that they address guidance and regulatory issues related to HPI systems, but do not directly consider aging degradation and its effect on the systems. Each of the important documents is described in the following paragraphs. All of these codes and standards could be considered for modification to include aging degradation considerations.

9.1 Code of Federal Regulations

The Code of Federal Regulations 10 CFR 50.46, 10 CFR 50.55a, and 10 CFR 50, Appendices A and B, address the ECCS in nuclear power plants (see Reference 18). Code 10 CFR 50.46 identifies the acceptance criteria for nuclear power plant emergency core cooling systems. Code 10 CFR 50.55a specifies the codes and standards that must be adhered to for inservice inspections. Appendix A includes general design criteria that cover requirements for design, fabrication, erection, and testing of systems and components important to safety. Subjects such as quality records, protection against natural phenomena, environmental and missile design bases, and system failure modes are addressed. Appendix B establishes quality assurance requirements for the design, construction, and operation of systems and components important to safety. These regulations are focused on requirements the design must meet, such as peak cladding temperatures, and testing and inspection capabilities. These regulations are implemented and explained in detail in the appropriate regulatory guides, the Standard Review Plan, ASME Code Section XI, and other associated codes and standards.

9.2 NRC Regulatory Guides

Several NRC regulatory guides set requirements on the design, operation, and quality assurance of HPI systems.⁸⁰⁻⁸⁴ Some regulatory guides are covered in Section 9.5 because they are directly related to specific IEEE standards.

Regulatory Guide 1.1 (formerly Safety Guide 1) requires that ECCS be designed so that adequate net positive suction head is provided to system pumps, assuming maximum expected temperatures of the pumped fluids and no increased containment pressure over the pressure that is present prior to the system initiation.

A list of typical safety-related activities that should be covered by written procedures is presented in Regulatory Guide 1.33. This list is intended to be a guide of typical examples and not an inclusive listing of all needed procedures. The procedures listed include administrative, operating, abnormal and emergency conditions, and maintenance activities. However, specific procedures for surveillance and testing activities designed to detect aging degradation are not included.

Regulatory Guide 1.47 requires an HPI system status indication in the control room when the HPI system is deliberately inoperable or bypassed.

The trash racks and debris screens required to protect the ECCS suction pipes in the injection water sources are described in Regulatory Guide 1.82.

Regulatory Guide 1.89 requires that certain electrical equipment important to safety be designed to remain functional under postulated accident conditions and that design control measures such as testing be used to check the design adequacy. This guide specifically addresses synergistic degradation effects and aging effects such as thermal aging of high-temperature equipment. While all environmental factors that affect life are to be considered, the regulatory guide does not specifically address factors such as corrosion, dirt, wear, fatigue, and embrittlement of electrical components. The guide also states that periodic surveillance and testing programs are acceptable to account for uncertainties regarding aging degradation that may affect equipment functionality.

Regulatory Guide 1.148 provides requirements that serve as the basis for construction,

operability assurance, inservice testing, and relationships to other standards for valves.

9.3 NRC Standard Review Plan

The NRC Standard Review Plan provides guidance to NRC staff for performing safety reviews of applications to construct or operate nuclear power plants (see Reference 21). It also serves to make information on regulatory matters readily available and to improve communication and understanding of the review process with the nuclear power industry. This document also implements acceptance criteria and guidelines based on meeting the requirements set forth in ASME Code Section XI and the Code of Federal Regulations 10 CFR 50 (see References 18 and 54), including the General Design Criteria.

The Standard Review Plan requires compliance with regulations that require equipment to be designed with the capability to be tested periodically. This includes leakage testing to verify the isolation capabilities of containment penetrations and valves and testing to verify operational readiness of safety-related pumps and valves. A testing program is required to be in agreement with ASME Code Section XI and must also include safety-related components that are not covered by Section XI. This program must also establish reference values for measured test parameters and then specify a periodic testing schedule, allowable limits on the measured parameters, and corrective actions to be followed when the limits are exceeded. Electrical and electronic equipment is required to comply with a number of the standards published by the Institute of Electrical and Electronics Engineers covering areas such as harsh environments. The overall testing program must demonstrate that pumps and valves operate on normal and emergency power, and that water pressure and flow are delivered as designed when an initiation signal is received.

9.4 ASME Code Section XI

Section XI, Rules for Inservice Inspection of Nuclear Power Plant Components, of the ASME Boiler and Pressure Vessel Code (see

Reference 54) provides rules for the examination, testing, and inspection of components and systems in a nuclear power plant. Section XI is intended to begin when the construction code requirements have been satisfied. The section mandates a program of examinations, testing, and inspections to verify adequate safety. The primary HPI system components covered in Section XI are piping, pumps, and valves. Examination requirements, techniques, acceptance standards, and frequencies are described in some detail for each component grouping. In 1988, Subsections IWP and IWV (covering pumps and valves) were removed from ASME Code Section XI and, with some modifications, became ASME Operating and Maintenance Standards OM-6 and OM-10, respectively. These standards are described in Section 9.7.

These subsections of ASME Section XI would be appropriate places to include additional techniques and monitoring methods for detection and quantification of aging degradation. Detailed testing results could be maintained for tracking aging degradation and maintenance through the testing and maintenance records and reports requirements.

9.5 IEEE Standards

The Institute of Electrical and Electronics Engineers (IEEE) generates standards to establish requirements for the safety-related functional performance and reliability of electrical and electronic components and systems. Many of these standards are considered in the Standard Review Plan and are endorsed by regulatory guides, while others are not specifically endorsed but are recommended for guidance.

Some of the IEEE standards important to HPI systems and their implementing or supplementing Regulatory Guides include:

IEEE Standard 279

Criteria for Protection Systems for Nuclear Power Generating Stations

Codes and Standards

Regulatory Guide 1.22

Periodic Testing of Protection System Actuation Functions

Regulatory Guide 1.47

Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

Regulatory Guide 1.53

Application of the Single Failure Criterion to Nuclear Power Plant Protection

Regulatory Guide 1.62

Manual Initiation of Protective Actions

Regulatory Guide 1.75

Physical Independence of Electric Systems

Regulatory Guide 1.105

Instrument Setpoints

Regulatory Guide 1.118

Periodic Testing of Electric Power and Protection Systems

IEEE Standard 323

General Guide for Qualifying Class I Electrical Equipment for Nuclear Power Generating Stations

Regulatory Guide 1.89

Qualification of Class 1E Equipment for Nuclear Power plants

IEEE Standard 338

Criteria for Periodic Testing of Nuclear Power Generating Station Protection Systems

Regulatory Guide 1.118

Periodic Testing of Electric Power and Protection Systems

IEEE Standard 382

Guide for Type Test of Class I Electric Valve Operators for Nuclear Power Generating Stations

Regulatory Guide 1.73

Qualification Tests of Electric Valve Operators Installed Inside the Containment of Nuclear Power Plants

IEEE Standard 383

Standard for Type Test of Class 1E Electric Cables, Field Splices, and Connections for Nuclear Power Generating Stations

Regulatory Guide 1.131

Qualification Tests of Electric Cables, Field Splices, and Connections for Light-Water-Cooled Nuclear Power Plants.

In addition, several IEEE Standards are recommended in the Standard Review Plan for guidance purposes, although the NRC has not endorsed them by issuing a regulatory guide. Some of these recommended standards are:

IEEE Standard 381

Criteria for Type Tests of Class 1E Modules Used in Nuclear Power Generating Stations

IEEE Standard 649

Qualifying Class 1E Motor Control Centers for Nuclear Power Generating Stations

IEEE Standard 650

Qualification of Class 1E Static Battery Chargers and Invertors for Nuclear Power Generating Stations.

9.6 Equipment Qualification Standards

The NRC requires that nuclear power plant equipment important to safety must be capable of performing its intended function throughout its installed life. The majority of the emphasis on equipment qualification has been focused on

electrical equipment, but recent efforts on mechanical equipment have been increased. The standards that pertain to these requirements are listed below.⁸⁵

IEEE Standard 323

IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations (sets the requirements to ensure that safety-related electrical equipment is capable of performing its intended function)

IEEE Standard 627

Standard for Design Qualification of Safety Systems Equipment Used in Nuclear Power Generating Stations

Regulatory Guide 1.73

Qualification Tests of Electric Valve Operators Installed Inside the Containment of Nuclear Power Plants

Regulatory Guide 1.89

Qualification of Class 1E Equipment for Light-Water-Cooled Nuclear Power Plants (endorses IEEE Standard 323)

Regulatory Guide 1.100

Seismic Qualification of Electric Equipment for Nuclear Power Plants

NUREG-0588 Rev. 1

Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment (supplements IEEE Standard 323 with guidance on how to establish environmental service conditions, how to select appropriate methods for qualifying equipment in different areas of the plant, and on other areas such as aging, margins, and documentation)

10 CFR 50.49

Covers regulations regarding environmental qualification of 1E and some non-1E electric equipment

NRC IE Circular 78-08

Environmental Qualification of Safety-Related Electrical Equipment at Nuclear Power Plants (requests licensees to review safety-related electrical equipment qualification)

NRC IE Bulletin 79-01B

Environmental Qualification of Class 1E Equipment (requests a detailed review of environmental qualification of Class 1E electrical equipment to ensure that the equipment will function under postulated accident conditions and design basis environments)

ANSI B16.41-1983

Functional Qualification Requirements for Power-Operated Active Valve Assemblies For Nuclear Power Plants

ANSI N278.1-1975

Self-Operated and Power-Operated Safety-Related Valves Functional Specification Standard (provides a generic list of functional requirements for consideration in the preparation of a valve functional specification).

9.7 ASME Operating and Maintenance Standards

ASME issues standards for operation and maintenance of nuclear power plants that meet the testing requirements of 10 CFR 50.55. The operating and maintenance standards provide inservice testing requirements for assessing the operational readiness of systems and components that perform a specific function in shutting down a reactor or in mitigating the consequences of an accident and are provided with an emergency power source. In addition, they describe the records to be maintained on the results of the inservice testing

Codes and Standards

performed on these systems and components. The standards that are relevant for HPI systems are listed below.

OM2-1982

Requirements for Performance Testing of Nuclear Power Plant Closed Cooling Water Systems

OM3-1982

Requirements for Preoperational and Initial Startup Vibration Testing of Nuclear Power Plant Piping Systems

OM4-1982

Examination and Performance Testing of Nuclear Power Plant Dynamic Restraints (Snubbers)

OM6-1988

Inservice Testing of Pumps in Light-Water-Reactor Power Plants (replaces ASME

Boiler and Pressure Vessel Code, Section XI, Subsection IWP)

OM10-1988

Inservice Testing of Valves in Light-Water-Reactor Power Plants (replaces ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWV).

9.8 Summary of Modifications that will Improve Consideration of Aging Degradation

Table 36 describes modifications to some of the codes and standards that would improve aging degradation considerations. These modifications would specifically identify the aging degradation concerns relevant to the components and requirements covered.

Table 36. Code and standard modifications that would improve aging degradation considerations.

Code/standard	Modification
Technical Specifications	Consider relaxing HPI system response time from 30 to 60 seconds
ASME Code Section XI	Include testing and maintenance record requirements for tracking aging degradation
Regulatory Guide 1.33	Extend list of safety-related activities that should be covered by written procedures to include aging concerns and specific inspections for detecting aging degradation
Regulatory Guide 1.89	Identify environmental factors that are known to contribute to aging degradation
IEEE Standards	Include consideration of aging degradation, including techniques to detect and reduce this degradation
Equipment Qualification Standards	Include consideration of aging degradation and techniques to detect and reduce this degradation
ASME Operating and Maintenance Standards	Include consideration of aging degradation and techniques to detect and reduce this degradation Include valve diagnostic testing and data trending

10. CONCLUSIONS

The results presented in this section are the product of the Phase I study for understanding and managing aging in BWR HPI systems. The BWR HPI systems are normally in standby mode, but are critically important to plant safety when they are demanded to inject water into the reactor pressure vessel. An inoperable HPI system, when it is required, can present a significant challenge to plant safety. This study has identified aging degradation that is currently occurring and causing component failures and system inoperabilities. The following conclusions have been developed and supported by failure data from several databases and from plant-specific records. They will provide a technical basis for possible future research and work to mitigate aging degradation and improve the reliability of BWR HPI systems. A summary of significant aging considerations is presented in Table 37.

The most common failure modes for HPI components are degraded operation, loss of function, low injection flow, leakage, and failure to operate. This includes such failure modes as valves failing to open completely, the turbine failing to operate, and relays failing to function.

The most common aging failure causes in HPI systems include wear, corrosion, dirt, improper lubrication, improper maintenance, fatigue, and the synergistic effects of other mechanisms. These are the most important factors in HPI component failures and system unavailability, and the aging rate appears to be slightly increasing with time.

The most commonly failed components are valves, valve operators, instrumentation and control components, pumps, turbines, piping, and pipe supports. The aging and other mechanisms causing these failures include wear, water hammer, improper lubrication, setpoint drift, and out-of-calibration instrumentation. Approximately 50% of these failures are detected during surveillance testing, and others are detected by operational abnormalities, maintenance, and routine observations. However, about 11.4% of the

failures in the LER database and 10.8% of the failures in the NPRDS database cause a complete loss of system function. Components that most often cause a loss of system function are valve operators, valves, circuit breakers, mechanical controllers, bistable switches, and the turbine. Many small leaks and instrumentation and control problems are identified and repaired before a major failure occurs.

MOVs and HPCI turbine-driven pumps are the most risk-significant components and are among the components that most commonly fail. HPI systems generate a small portion of the total plant risk; several other systems exceed HPI system plant risk, including ac and dc power, standby liquid control, service water, reactor protection, and RCIC.

The analysis of the failure data shows that the majority of failures are detected during testing. If surveillance and monitoring programs are highly effective, very few failures will occur during testing. However, the high failure rate during testing activities indicates that current surveillance and monitoring programs are not detecting aging degradation prior to failure.

The codes and standards relevant to the HPI systems have one thing in common: they address guidance and regulatory issues; however, most do not directly consider aging degradation and its effects on system operability and reliability. The modifications described in Section 9 and summarized in Table 36 could be incorporated to include aging degradation considerations.

10.1 Improvement of System Reliability

The incidences of water hammer events could be reduced by modifying isolation valves to include gradual opening capability and by proper training on opening sequence procedures. In addition, steam entrainment could be prevented by modifying drain pots or by verifying that they have large enough capacity to operate at correct

Table 37. Summary of aging degradation for BWR HPI systems.

Component	Stressors	Degradation mechanisms	Failure modes	Detection methods
Valves	Operation, testing, dirt, improper maintenance	Wear, fatigue	Degraded operation, failure to operate, binding	Surveillance testing, advanced diagnostics, maintenance, visual inspection
Valve operators	Contact arcing, moisture, operation, temperature, testing, dirt, high stress	Wear, shorting, grounding, thermal degradation, degraded insulation	Degraded operation, degraded torque spring	Surveillance testing, advanced diagnostics, maintenance, visual inspection
Instrumentation and control	Humidity, dirt, temperature, radiation, improper maintenance, operation, vibration	Corrosion, increased resistance/friction, embrittlement	Loss of function	Surveillance testing
Pumps	Lubrication problems, testing	Wear, fatigue	Low injection flow, failure to operate	Surveillance testing, ASME Section XI inservice testing
Turbine (HPCI only)	Lubrication problems, testing, improper maintenance, vibration, pressure, temperature, dirt	Wear, fatigue	Degraded operation, failure to operate	Surveillance testing, maintenance, visual inspection
Pipe	Single-phase flow, two-phase flow, dirt, water hammer, pressure, testing, temperature gradients, vibration	Corrosion, fatigue, erosion, erosion-corrosion	Leakage, cracks, large deformations	Surveillance testing, ASME Section XI inservice testing, volumetric and surface examination
Pipe supports	Water hammer, testing, improper maintenance, vibration, dirt	Fatigue, overload, wear	Failure to lock up, lock up under static load, leakage, broken, pulled out of mounting temperature, radiation	Surveillance testing, visual inspection

levels; also, developing procedures for correct operating sequences would help. Discharge to voided lines could be prevented by installing vacuum breakers; by installing keep-full, void-detection; and venting systems, and by developing proper operating procedures.

The study by GE and EPRI (see Reference 7) shows that ECCS response time can be relaxed while ensuring a substantial core safety margin. That report recommends consideration be given to relaxing the HPCI response time to 60 seconds. This could reduce wear and aging degradation caused by fast starts and improve system reliability. Each plant can consider its need for improvements that could be provided by this change.

Also, cold quick-start tests, without prewarming of the HPI system, has been determined to be the only test that ensures that the HPI system will function as designed when demanded. Critically analyzing the required frequency of cold, quick-start tests will ensure maximum system reliability and minimum component stress.

Implementing a time delay on the isolation logic for high-steam flow in the turbine inlet line will reduce spurious isolations immediately after automatic-initiation and those caused by pressure transients and setpoint drift.

Modification of HPCI systems so they will switch to recirculation to the CST, after water level recovery has been verified, will leave the system running and available for immediate return to full service without requiring another startup challenge. This could reduce stresses on the system and reduce system lockouts.

Modification of 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 can prevent damage to the pump from deadhead operation.

Review of motor-operated valve power cable size will ensure that they are capable of conducting the locked rotor current, which is much higher than the nameplate full load current. Any power

cables not capable of carrying the locked rotor current can then be replaced.

Steady performance deterioration can be more reliably detected by comparing the MOV stroke time to a set reference value and not the previous test value; this will require an approved variation from the ASME Section XI requirements. Including all safety-related and position-changeable MOVs in the in-service testing program will ensure that they function under design-basis conditions.

Routine electrical backseating of valves over-stresses the valve stem and valve seats. This may lead to failures such as valve stem breaking or elongation, backseat damage, or stem nut cracking.

Inspection of the valves in the HPI system can reveal aging degradation. Special attention should be paid to materials susceptible to stress corrosion cracking, such as type 410 stainless steel bolting. Also, inspection of bolted bonnet swing check valves with 14-4PH alloy swing arms can reveal fabrication defects and high residual stresses that may indicate incipient disc-swing arm separation.

Improvements to testing and surveillance programs similar to those described in Section 6 could be implemented wherever applicable to make the HPI systems more reliable. Also, Reference 30 states that improvements to preventative maintenance programs can eliminate many HPI failures. Plants can review their programs that affect HPI system reliability, such as preventative maintenance, to determine the need to improve these programs and to learn from plants with low failure rates. Since valves and valve operators are the components with the most failures, these programs could include a root cause analysis of valve and valve operator failure, additional ASME Section XI testing as recommended in Generic Letter 89-10, and trending of valve operating characteristics.

Turbine and pump lubricating oil must be as specified in the vendors technical manuals to prevent aging degradation. This can be verified

Conclusions

routinely to prevent corrosion caused by the use of improper or contaminated oil.

The amount of time the HPCI systems are unavailable because of maintenance being performed increases as the systems and components age. This increased unavailability can be accounted for in the PRA for each plant. HPCS system unavailability can be monitored to determine long-term trends.

The modifications to codes and standards described in Sections 6 and 9 can be implemented to ensure the consideration of aging degradation in the design, testing, and maintenance of HPI systems and components. See Table 36 for more specific suggestions.

10.2 Phase II Work

This section describes the suggestions for Phase II research for the BWR HPI system. Several approaches could be taken to resolve Phase II issues. These include the group performing the research (NRC or industry) and the level at which the research is conducted (system or component). The NRC could choose the approach or combination of approaches that it determines will best provide the information needed on BWR HPI system aging.

Valves have been identified as the most troublesome component in the HPI systems and, therefore, are the focus of suggested Phase II research. Performance evaluation of valves is

currently underway in several other NRC research programs, and the high energy and flow interruption gate valve testing program is of particular interest. An additional program can be performed to evaluate the tribological characteristics of increased friction that results in additional force to operate a valve. Also, methods of reducing operating friction in valves can be studied to identify possible areas for improvement. The results of this research could then be directly applied to improving maintenance programs and HPI system reliability.

We conclude that performing a detailed review of inspection, testing, and maintenance practices for the HPI systems for several plants would benefit those systems. This program will identify strengths and weaknesses in current plant programs for detecting and mitigating aging degradation. The results of this research will then be used to provide recommendations where applicable for specific inspection, testing, and maintenance activities for detecting, monitoring, and controlling aging effects in HPI systems.

Instrumentation and control component failures were near the top of the list of troublesome components; therefore, we conclude that identifying advanced methods for monitoring and surveillance would improve detection of aging degradation occurring in these components in the HPI systems. Before failures occur, which would cause the system to be unavailable, these methods would detect aging degradation of the electrical components, the necessary power and data cables, and connections.

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The purpose of high pressure injection systems is to maintain an adequate coolant level in reactor pressure vessels, so that the fuel cladding temperature does not exceed 1,200°C (2,200°F), and to permit plant shutdown during a variety of design basis loss-of-coolant accidents. This report presents the results of a study on aging performed for high pressure injection systems of boiling water reactor plants in the United States. The purpose of the study was to identify and evaluate the effects of aging and the effectiveness of testing and maintenance in detecting and mitigating aging degradation. Guidelines from the United States Nuclear Regulatory Commission's Nuclear Plant Aging Research Program were used in performing the aging study. Review and analysis of the failures reported in databases such as Nuclear Power Experience, Licensee Event Reports, and the Nuclear Plant Reliability Data System, along with plant-specific maintenance records databases, are included in this report to provide the information required to identify aging stressors, failure modes, and failure causes. Several probabilistic risk assessments were reviewed to identify risk-significant components in high pressure injection systems. Testing, maintenance, specific safety issues, and codes and standards are also discussed.

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