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Recommendations for the Treatment of Aging in Standard Technical Specifications

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Prepared for
Division of Engineering Technology
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U.S. Nuclear Regulatory Commission
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Abstract

As part of the U.S. Nuclear Regulatory Commission's Nuclear Plant Aging Research Program, Pacific Northwest Laboratory (PNL) evaluated the standard technical specifications for nuclear power plants to determine whether the current surveillance requirements (SRs) were effective in detecting age-related degradation. Nuclear Plant Aging Research findings for selected systems and components were reviewed to identify the stressors and operative aging mechanisms and to evaluate the methods available to detect, differentiate, and trend the resulting aging degradation. Current surveillance and testing requirements for these systems and components were reviewed for their effectiveness in detecting degraded conditions and for potential contributions to premature degradation. When the current surveillance and testing requirements appeared ineffective in detecting aging degradation or potentially could contribute to premature degradation, a possible deficiency in the SRs was identified that could result in undetected degradation. Based on this evaluation, PNL developed recommendations for inspection, surveillance, trending, and condition monitoring methods to be incorporated in the SRs to better detect age-related degradation of these selected systems and components.

Summary

Current standard technical specifications (STS) surveillance and testing procedures can be useful in detecting aging degradation in dynamic plant equipment, such as pumps, valves, breakers, and switches. However, aging effects have not always been recognized or addressed explicitly in the surveillance requirements (SRs); many significant forms of aging degradation might not be detected before equipment failure. In some cases, the methods and frequency of testing contribute to premature degradation. As part of the U.S. Nuclear Regulatory Commission's Nuclear Plant Aging Research (NPAR) Program, Pacific Northwest Laboratory has evaluated the STS for nuclear power plants for selected systems and components to determine the effectiveness of current SRs in

- detecting degraded conditions before system and component failure
- assessing potential contributions to premature degradation
- identifying, from the NPAR results, parameters or indicators useful to monitor the degraded state of system and components
- developing recommendations for inspection, surveillance, trending, and condition monitoring methods, as part of SRs, to evaluate age-related degradation.

In addition to helping maintain the safety envelope with time, the assessment provides an opportunity to reduce the regulatory burden and enhance cost effectiveness by focusing on the specific SRs needed to effectively detect and trend aging degradation.

In summary, an evaluation of the STS SRs associated with selected nuclear power plant systems and components to determine their effectiveness in the detection of age-related degradation effects has been accomplished. Current SRs can be useful but are generally ineffective in detecting age-related degradation in dynamic equipment. When the SRs were initially prepared, aging effects were not recognized as the problem they have become. Indeed, several industry initiatives that are now active are a result of unforeseen operability or aging concerns. Further, some SRs even contribute to age-related degradation. Review of NPAR results and other publications identified indicators useful to detect and monitor the age-related degradation that is active in these systems and components. Finally, recommendations to augment the SRs are made based on identifying gaps in the coverage of the age-related degradation indicators by the current SRs.

These STS aging assessments have been conducted for the Auxiliary Feedwater System (AFWS), battery chargers and inverters, check valves (CVs), the Class 1E power system, the Emergency Diesel Generator (EDG) system, motor-operated valves (MOVs), the Reactor Protection System (RPS), the Service Water System (SWS), snubbers, and the Residual Heat Removal (RHR) system.

Auxiliary Feedwater System

The AFWS, or emergency feedwater system, is a safety-related system that normally supplies high-pressure feedwater to the steam generators (SGs) during startup, hot standby, and shutdown. The AFWS is also designed to provide an adequate supply of feed (cooling) water from a seismic Category I water source to the SGs in the event of a number of anticipated transients and design-basis accidents. The most important AFWS stressors and aging mechanisms include wear, corrosion, erosion, fatigue, vibration, thermal fatigue, fretting, cavitation, lubricant fouling, pitting, fretting corrosion, and crevice corrosion.

The review of existing SRs for AFWS suggest that the focus is primarily on operability concerns and not on addressing the detection and trending of aging degradation. Major components are periodically tested at normal conditions, as opposed to demand (emergency) conditions, for function and readiness. Nearly 20 percent of AFWS failures are detected through operational abnormalities (i.e., during operation/testing). The existing SRs for the AFWS may contribute to aging degradation by testing the system pumps to frequently at low-flow conditions. This type of testing has proven to degrade pump operation.

The NPAR studies on the AFWS have developed additional recommendations to address age-related issues. These recommendations include conducting systematic root-cause analyses; visually examining pump parts and monitoring pump parameters; inspecting system valves; evaluating system piping; and checking system instruments, instrumentation channels, and controls.

Battery Chargers/Inverters

Battery chargers provide an interface between the alternating current (ac) and direct current (dc) systems, and rectify their ac input to a dc output for float-charging the associated batteries and supplying power to complementary loads. Inverters are used to both invert dc power supplies into ac power and as an uninterruptible source of ac power to plant essential instrumentation in the plant, the plant computer, and in some cases, an integrated control system. Major contributors to battery charger/inverter aging are an overtemperature environment and electrical transients (e.g., voltage spikes, high or low voltages, or momentary power interruptions). Other aging mechanisms related to battery chargers/inverters are wear and loose connections.

The review of existing SRs for battery chargers/inverters suggests that the focus is primarily on operability and not on detecting and trending aging degradation. None of the existing SRs are intended to monitor the onset of or directly indicate the age-related degradation of the battery chargers and inverters; however, niether do they contribute to aging. However, electrical transients associated with the SR-mandated start and run of the emergency diesel generators have caused inverter failures.

The NPAR studies on battery chargers/inverters have developed additional recommendations that address age-related issues. These recommendations include examining accessible connections and components both visually and by infrared thermography, monitoring cabinet temperatures and silicon-controlled rectifier junction temperatures for overheating, checking for the presence of potentially damaging electrical transients, and conducting selected online and offline tests.

Class 1E Power Systems

Class 1E is the safety classification of the electrical equipment and systems that are essential to emergency reactor shutdown, containment isolation, reactor core cooling, and containment and reactor heat removal, or are otherwise essential in preventing a significant release of radioactive material to the environment. All safety-related equipment and systems are designated as Class 1E. Nonsafety-related loads are also supplied from Class 1E power busses during normal operation. These nonsafety-related loads are shed whenever an emergency condition exists that requires actuation of the engineered safeguards equipment.

Major aging mechanisms of the Class 1E system include corrosion, high temperature, fatigue, arcing, abrasions, oxidation, cracking, and embrittlement. Inadequate maintenance can also have a negative impact. While the exact impact of the mechanisms are plant-specific, NPAR studies indicated that the components that fail most often are breakers, batteries, and transformers. One Probabilistic Risk Assessment identified ac breakers, transformers, and busses as being the most risk-significant of the Class 1E power system components.

The review of existing SRs of Class 1E Power Systems focus primarily on operability concerns and not on addressing the detection and trending of aging degradation. None of the SRs for the ac power system have the capability to detect or moitor the onset of age-related degradation. However, the SRs for the dc power system associated wth the batteries do have the capability to detect and monitor the onset of the aging degradation if the results are properly trended.

The NPAR studies of Class 1E Power Systems have developed additional recommendations that address age-related issues. The recommendations include monitoring cables and cable penetrations by visual and testing methods to identify evidence of aging. For other components, recommendations include monitoring of radiation and environmental conditions for evidence of potentially degrading conditions. The majority of the recommendations use standard techniques, but some advanced techniques of infrared thermography for batteries, circuit breakers, relays, and transformers are recommended.

Check Valves

Check valves are simple in design and function. They are used extensively within Pressurized-Water Reactor (PWR) and Boiling-Water Reactor (BWR) nuclear power plants for service in safety-related and balance-of-plant systems. The several types of CVs used, depending on the application and the system configuration, include swing-check, horizontal-lift, vertical-lift, piston-lift, ball, stop-check, tilting-disc, and duo-check CVs. The stressors and aging mechanisms that affect CVs include thermal stresses, adverse environmental conditions, radiation, vibration, contamination, vibration-induced fatigue, mechanical stress abrasions, corrosion, oxidation, cracking, and embrittlement. Inadequate maintenance can also contribute to premature degradation.

The review of existing SRs for CVs suggests that the focus is primarily on component operability concerns and not on condition monitoring to detect and trend age-related degradation. The STS specify that the inspection and testing of American Society of Mechanical Engineers (ASME) Class 1, 2, and 3 components is required to be in accordance with Section XI of the ASME Boiler and Pressure Vessel

Code. Section XI requires CV testing that involves only two parameters: operation and seat leakage. This testing, which is reflected in the SRs, is not adequate to ensure CV operability.

The NPAR studies of CVs identified additional recommended actions that address CV age-related problems. These recommendations include visually examining the CVs whenever they are opened and using detection methods, such as acoustic emission monitoring combined with ultrasonic examination, external magnet monitoring, or magnetic flux signature analysis to provide a wide range of information that can be trended over time to determine aging effects on CVs and to identify potential age-related degradation.

Emergency Diesel Generator System

The EDG system provides the backup electrical power needed by a nuclear power plant in the event of a loss of offsite ac power (LOOP). A reliable EDG system is essential because of the serious consequences from failure to produce electrical power after a LOOP. The most important stressors and aging mechanisms of the EDG system include corrosion, vibration-induced fatigue and fastener loosening, oxidation, thermal stresses, shock, contamination, adverse environmental conditions, biofouling, and improper or excessive operation.

The review of existing SRs for the EDG system suggests that the focus is primarily on operability and not on detecting and trending aging degradation. Some of the more frequently performed tests have the potential to contribute to the premature aging degradation of EDG subsystems and components. This may be particularly true for SRs associated with fast starting and engine loading, engine and generator overspeed, load rejection tests, and engine overload testing.

The NPAR studies of the EDG system have developed additional recommendations that address age-related issues. Those recommendations include eliminating short engine run times and excessive idle time when possible, reducing the test load application rates, increasing the maximum EDG start time, significantly reducing the number of engine starts per month or year, and reducing the EDG testing loads. Some of these recommendations have been incorporated in the STS; incorporation of the remainder is encouraged.

Motor-Operated Valves

Motor-operated valves are used extensively in PWR and BWR nuclear power plants for service in safety-related and balance-of-plant systems. The most commonly used valve types are gate, globe, and butterfly. Stressors and aging mechanisms of MOVs include thermal stresses, adverse environmental conditions, improper or excessive voltages and currents, radiation, vibration, ohmic heating, dirt or dust contamination, vibration-induced fatigue, mechanical stress abrasions, corrosion, cracking, and embrittlement. Inadequate maintenance can also contribute to premature degradation of MOVs.

The review of existing SRs for MOVs suggests that the focus is primarily on operability concerns and not on condition monitoring. Of the 40 MOV-related SRs in the Westinghouse plant STS, two pertain to leakage, 20 to operation, and 18 to status verification. The MOV testing required by Section XI of the ASME Boiler and Pressure Vessel Code involves only two parameters: stroke time and seat leakage. This testing, which is reflected in the SRs, is useful to determine MOV condition as a result of aging degradation. However, testing is usually performed without fluid pressure or flow in associated piping. The current SR testing alone is not adequate to ensure MOV operability.

The NPAR studies of MOVs have identified additional recommended actions that address MOV age-related problems. These include visually examining risk-significant and prioritized MOVs for evidence of aging degradation and using motor current signature analysis, other MOV diagnostic analysis systems, thermography, and root-cause analysis to provide a wide range of information on aging degradation.

Reactor Protection System

The RPS is the principal information-gathering and decision-making system to ensure safe operation of the reactor. The RPS measures critical parameters that describe whether the reactor is operating within a safe performance envelope, alarms when an unsafe performance condition is being approached, and initiates a reactor trip when safe operating limits are exceeded. If an accident does occur, the RPS initiates engineered safety features to prevent further development or deterioration of potentially unsafe conditions in mitigating the severity and consequences of the accident.

Reactor protection system stressors and aging mechanisms for sensors include temperature, moisture, and humidity, which lead to calibration drift, out-of-calibration conditions, and circuit failures. Reactor protection system stressors and aging mechanisms for process logic devices include temperature, foreign material, and contact surface degradation. Inadequate or improper maintenance of the RPS can also contribute to premature degradation.

The current SRs specify calibration and test requirements for RPS modules. These requirements are useful to determine RPS module condition. If testing indicates marginal performance, corrective action can be taken to prevent failure during operation. However, testing cannot predict a module failure or the effects of aging. More important, a significant portion of the RPS failures are not detected by the current SRs. Almost half of the RPS failures are being detected by nonroutine methods, such as operational abnormality, special inspection, audiovisual alarm, incidental observation, and corrective maintenance.

The NPAR studies of the RPS have developed additional recommendations that address age-related issues. These recommendations include examining representative samples of risk-significant and prioritized RPS modules using infrared thermography, redundant instrumentation monitoring, and multiple signal analyses techniques.

Service Water System

Service water systems perform vital safety functions in nuclear reactors. They provide the final link between the reactor and the ultimate heat sink, and also provide cooling to safety-related equipment, such as EDG and emergency core cooling systems.

Depending on the design, all or part of the SWS may be exposed to raw or relatively aggressive, treated water. Therefore, SWS components are subject to a range of age-related degradation mechanisms, including biofouling, microbiologically influenced corrosion, corrosion, erosion, chemical attack, cavitation, and wear.

The existing SRs for SWSs focus primarily on operability concerns, such as verifying that SWS valves are positioned correctly, and not on addressing the detection and trending of aging degradation. Also, incomplete or ineffective root-cause analysis on failed SWS equipment has hampered efforts to detect and resolve age-related degradation.

The NPAR studies of the SWS have developed additional recommendations that address age-related SWS issues. These recommendations include conducting effective root-cause analyses on failed SWS equipment and examining, testing, and trending test results for SWS components, such as heat exchangers, pumps, piping, valves, and intake structures.

Snubbers

Mechanical and hydraulic snubbers on safety-related piping systems and components reduce pipe and component stress and restrain excessive movement under transient, faulted, and emergency conditions. The primary aging concern for hydraulic snubbers is degradation of elastomeric seals. The two most significant aging stressors associated with such degradation are heat and radiation. Component vibration is a significant cause of degradation in mechanical snubbers. Many nuclear plants have reported degradation of mechanical snubber performance due to solidification of lubricants in high-temperature environments. Moisture, which can cause internal corrosion, and dynamic load transients are other causes of mechanical snubber failure.

There are no snubber-related SRs in the Westinghouse plant STS. The effects of aging and the determination of "operability" can be accomplished by an in-depth snubber test and maintenance program, which is required per GL 84-13, "Technical Specification for Snubbers." Snubbers are also subject to the requirements of the Code of Federal Regulations, which specifies inspection and testing criteria. These criteria are contained in Section XI and Operations and Maintenance Standard, Part 4. The service-life monitoring recommendations for mechanical and hydraulic snubbers that resulted from the NPAR snubber aging studies were submitted for possible incorporation in the next revision of the ASME OM Code, Subsection ISTD. It is concluded that snubbers are adequately addressed by present regulatory requirements, and that no STS recommendations are needed.

Residual Heat Removal System

The RHR system performs several safety functions during the various modes of PWR and BWR nuclear power plant operation. Its primary function is to remove heat from the reactor core during normal shutdown, loss-of-coolant-accident (LOCA), and post-LOCA conditions. It may also assist in containment heat removal, containment spray operations, emergency reactor vessel level makeup, augmented fuel pool cooling, and refueling water level control and transfer operations. The RHR system, also known among the different plant types as the low-pressure coolant injection system, the decay heat removal system, or the shutdown cooling system, plays a vital role in the safe operation of the plant during all modes of normal, accident, and post-accident operation.

The existing SRs for the RHR system focus primarily on operability concerns and not on addressing the detection and trending of aging degradation. For example, one SR requires that RHR pumps be demonstrated to start on an actuation signal; another requires that RHR automatic valves be demonstrated to align to their correct positions on an actuation signal; yet others require the measurement of plant conditions within the RHR system, such as water levels, developed differential pressure, and flows.

NPAR studies of the RHR system have developed additional recommendations that address age-related issues. These recommended SRs address the need for trending operational parameters that would detect age degradation and allow timely corrective action.

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Acronyms

ac	alternating current
AEOD	Analysis and Evaluation of Operational Data
AFW	auxiliary feedwater
AFWS	auxiliary feedwater system
ATWS	anticipated transient without scram
ASME	American Society of Mechanical Engineers
BWR	Boiling-Water Reactor
CFR	U.S. Code of Federal Regulations
CST	condensate storage tank
CV	check valve
dc	direct current
EDG	emergency diesel generator
ESW	essential service water
FSAR	final safety analysis report
FW	feedwater
GDC	general design criteria
GL	Generic Letter
INEL	Idaho National Engineering Laboratory
LER	Licencee Event Report
LOCA	loss-of-coolant accident
LOOP	loss of offsite power
MDP	motor-driven pump
MOV	motor-operated valve
NPAR	Nuclear Plant Aging Research
NRC	U.S. Nuclear Regulatory Commission
PNL	Pacific Northwest Laboratory
PWR	Pressurized-Water Reactor
RHR	residual heat removal
RPS	reactor protection system
SG	steam generator
SR	surveillance requirement
STS	standard technical specifications
SWS	service water system
TDP	turbine-driven pump
UHS	ultimate heat sink
VAC	volts alternating current
VDC	volts direct current

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1.0 Introduction

As part of the U.S. Nuclear Regulatory Commission's (NRC's) Nuclear Plant Aging Research (NPAR) Program, Pacific Northwest Laboratory[(a)] has evaluated the standard technical specifications (STS) for selected systems and components to determine the effectiveness of current surveillance requirements (SRs) in detecting age-related degradation. The SRs ensure the operability and availability of safety-related systems and components by verifying and demonstrating that they are capable of performing their required functions. The following sections provide an overview of the STS, the purpose and scope of the STS aging evaluation, and the organization of the report as it addresses the findings for the nuclear power plant systems and components that have been evaluated to date.

1.1 Standard Technical Specifications

The *U.S. Code of Federal Regulations* (CFR) is a codification of the general and permanent rules published by the departments and agencies of the federal government. Codes and regulations of the NRC are contained in Title 10, "Energy" (10 CFR). The nuclear industry is subject to the requirements of 10 CFR.

The requirement for a nuclear power plant to have a final safety analysis report (FSAR), and the minimum information that it must include, is established in 10 CFR 50.34 (b). The FSAR describes the facility and presents its design basis, the limits on facility operation, and a safety analysis of the structures, systems, and components and of the facility as a whole. Items, such as the reactor core, the reactor coolant system, and the instrument and control system, are presented in their safety or nonsafety-related functions in relation to the safe operation of the nuclear power plant.

The requirement for a nuclear power plant to have technical specifications, and the minimum information that it must include, is established in 10 CFR 50.36. Technical specifications are an addendum to the operating license for a nuclear power plant. The operating license authorizes the licensee to possess, use, and operate the plant in accordance with the procedures and limitations set forth in the license and establishes minimum operating criteria for the plant. Failure to comply with these criteria may result in the reduction of the allowable operating power level or a complete shutdown of the plant. The bases for the criteria are the analyses and evaluations included in the FSAR. Plant operation within the established criteria ensures that the assumptions in the safety analyses are true for all operating conditions.

Technical specifications specify the equipment or condition that is required for safe operation of the plant and the actions that must be taken if the equipment or condition is not met or cannot be met. The technical specifications include what tests, calibrations, and examinations are required to ensure that applicable equipment and systems will perform their required function. For example, technical

(a) Pacific Northwest Laboratory (PNL) is operated by Battelle Memorial Institute for the U.S. Department of Energy under Contract DE-AC06-76RLO 1830.

specifications require that the safety injection system be in service for MODES 1 through 4 (reactor coolant system temperature greater than 200°F) and state actions to be taken if some or all of the safety injection system is unable to perform its intended design function.

Technical specifications address the following topics:

safety limit: Limits on important process variables that are necessary to reasonably protect the integrity of the physical barriers that guard against the uncontrolled release of radioactivity. When a safety limit is exceeded, the reactor is required to be shut down.

limiting safety system setting: Settings for automatic protective devices related to those variables having significant safety functions. When a limiting safety system setting is specified for a variable on which a safety limit has been placed, the setting shall be chosen to ensure that automatic protective action will correct the abnormal situation before a safety limit is exceeded. When a limiting safety system setting is exceeded, the reactor may be required to be shut down.

limiting condition for operation: The lowest functional capabilities or performance levels of equipment required for safe operation of the plant. When a limiting condition for operation is exceeded, remedial actions are required within a specified period of time.

surveillance requirement: Requirements relating to testing, calibrating, or examining systems or components to ensure that quality is maintained and, hence, that limiting conditions for operation will be met, that limiting safety system settings will not be exceeded, and that plant operation will be within safety limits.

design features: Features of the plant, such as materials of construction and structural arrangement, which, if altered or modified, would significantly affect safety. Design features are not covered by the above technical specification categories.

administrative controls: The provisions relating to organization and management, procedures, recordkeeping, review and audit, and reporting necessary to ensure that the plant is operated safely.

Technical specifications also normally include the following:

definitions: Definitions are given for the terms used in technical specifications. Because of the nuclear industry-specific nature of many words, the meaning of a particular word often requires a definition. Defined terms in technical specifications are shown in uppercase throughout the document, such as MODE or OPERABLE.

bases: The Bases section contains the rationale behind each SR. This section is not officially part of technical specifications, but is normally included in separate sections.

applicability: The Applicability section establishes when a limiting condition for operation and SR compliance is required and what actions to take if compliance is not met.

Technical specifications were written for each nuclear power plant during its construction. Though all resulting documents met the established requirements, a plethora of formats and styles emerged. This multiplicity led to a situation that was cumbersome, confusing, and unnecessarily complicated. Standard technical specifications were developed by the NRC to restore clarity and uniformity to these important documents. Standard technical specifications incorporate all technical specification requirements in a consistent and explicit manner. Though the nuclear industry is not required to rewrite technical specifications into standard technical specifications, a slow transition has begun. The STS evaluated and referenced in this report are the STS for Westinghouse plants and General Electric BWR-4 plants, issued by the NRC in September 1992 as NUREG-1431 (NRC 1992b) and NUREG-1433 (NRC 1992a), respectively.

1.2 Standard Technical Specifications Aging Assessment

Current STS surveillance and testing procedures can be useful in detecting aging degradation in dynamic plant equipment, such as pumps, valves, breakers, and switches. However, aging effects have not always been recognized or addressed explicitly in the SRs. Many significant forms of aging degradation might not be detected before equipment failure. In some cases, test methods and frequency of testing contribute to premature degradation (e.g., requirements for frequent fast starts of diesel generators and loads imposed on auxiliary feedwater pumps while testing in a low-flow pumping mode).

Based on these issues and considerations, the purpose of the STS aging evaluation is to

- determine the effectiveness of the SRs in detecting degraded conditions before system and component failure
- assess potential SR contributions to premature degradation
- identify, from the NPAR results, parameters or indicators useful to monitor the degraded state of systems and components
- develop recommendations for inspection, surveillance, trending, and condition monitoring methods, as part of SRs, to evaluate age-related degradation.

In addition to helping maintain the safety envelope with time, the STS aging assessment provides an opportunity to reduce the regulatory burden and enhance cost effectiveness by focusing on the specific SRs needed to effectively detect and trend age-related degradation.

1.3 Report Organization

This report was originally conceived with the intent to study all reactor systems and components that may impact the STS. Time and funding constraints required that only a sample of reactor systems and components be studied. The relative amount of NPAR research and concurrence of the NRC was the basis for selecting which systems and components would be evaluated.

For each system or component for which the STS are evaluated, the following will be provided: a description of the system or component; a discussion of the applicable stressors, aging mechanisms, and aging effects; methods for detecting degradation; an evaluation of the effectiveness of the SRs relative to detecting aging degradation; and recommendations for improving the SRs relative to aging effects.

Section 2.0 presents the STS aging assessments conducted for the Auxiliary Feedwater System, Section 3.0 for battery chargers and inverters, Section 4.0 for the Class 1E power system, Section 5.0 for check valves, Section 6.0 for the Emergency Diesel Generator, Section 7.0 for motor-operated valves, Section 8.0 for the Reactor Protection System, Section 9.0 for service water systems, Section 10.0 for snubbers, and Section 11.0 for Residual Heat Removal Systems. The references for the individual aging assessments are compiled in Section 12.0. Appendices are included with the individual sections.

2.0 Auxiliary Feedwater System

The Auxiliary Feedwater System (AFWS), or emergency feedwater system, is a safety-related system that normally supplies high-pressure feedwater to the steam generators (SGs) during startup, hot standby, and shutdown. The AFWS is also designed to provide an adequate supply of feed (cooling) water from a seismic Category I water source to the SGs. This is so that the SGs can act as heat sinks for decay heat removal from the reactor core and the primary system in the event of a number of anticipated transients and design-basis accidents, including loss of main feedwater, feedwater line break, small break loss-of-coolant accident, steam generator tube rupture, loss of offsite power, or a main steam line break. The AFWS may be required in other circumstances, such as the evacuation of the main control room, cooldown after a small break loss-of-coolant accident, or maintaining a water head in the SGs following a loss-of-coolant accident.

The AFWS operates over a long enough duration either to hold the plant at hot standby for several hours or to cool down the primary system [at a rate not to exceed limits specified in the standard technical specifications (STS)] to temperature and pressure levels at which the low-pressure decay heat removal system can operate. The AFWS must perform these functions whether or not offsite electrical power is available. Consequently, in addition to electrical motor-driven pumps, the system contains a steam turbine or a diesel-driven pump. The AFWS is actuated by its own control system. Electrical power is provided by the essential alternating current (ac) distribution subsystem. Actuation may be initiated by a loss of ac power, a loss of main feedwater pumps, a safety injection signal, low-low level in the SGs, an anticipated transient without scram (ATWS) mitigation system actuation signal, or a manual signal. There is adequate capacity in the seismic Category I water source to maintain the reactor at hot standby, then to cool the reactor coolant system to a temperature at which the decay heat removal system may be placed into operation.

Nuclear Plant Aging Research (NPAR) studies of the AFWS were conducted by Oak Ridge National Laboratory [Casada 1988, 1989, 1990, and 1992; Cox 1995 (DRAFT);[a] Kueck 1993]. These studies provided the technical basis for the STS aging evaluation for the AFWS. Additional information was obtained from publications by Adams (1992), Adams and Makay (1986), Blahnik et al. (1992), Kitch et al. (1988), Meale and Satterwhite (1987, 1988), and Shah and MacDonald (1989).

2.1 Auxiliary Feedwater System Description and Boundaries

There is no "typical" AFWS, because of variations in plant design, regulatory requirements, and designer preferences. However, for a four-loop Westinghouse plant, the AFWS usually consists of two motor-driven feedwater pumps (MDPs) and one steam turbine-driven feedwater pump (TDP); however, the number and types of pumps can vary at individual plants (there are various combinations of motor-, turbine-, and diesel-driven pumps within the AFWS pump population). Motor-driven pumps are sized for 50% capacity each and supply two SGs of a typical four-loop plant. The TDP is sized for 100% capacity and supplies all SGs of a typical four-loop plant. In two-loop or three-loop

(a) Cox, D. F. 1995. *Aging of Turbine Drives for Safety-Related Pumps in Nuclear Power Plants*, DRAFT, NUREG/CR-5857, ORNL-6713, prepared by Oak Ridge National Laboratory for the U.S. Nuclear Regulatory Commission, Washington, D.C.

plants, the number of SGs supplied by each MDP will vary, but the capacity of the MDPs versus the TDP will generally remain constant. When actuated, operation of only one MDP is normally required, though all pumps start and deliver rated flow on an actuation signal. The TDP will operate as long as steam is available from the main steam lines and direct current (dc) control power is available.

The preferred water source for normal operation for all auxiliary feedwater (AFW) pumps is the condensate storage tank (CST), a dedicated source of quality water. In the event that the CST is not seismically qualified, a separate seismic Category I water supply with automatic actuation capability is required for emergency operation. Technical specifications require that a minimum amount of water be reserved for the AFWS. An additional unlimited backup water supply, typically called essential service water (ESW), is supplied to the AFWS. A separate ESW header feeds each MDP, while the TDP can receive backup water from either ESW header. The ESW supply valves are opened either automatically or manually, depending on plant design, when both a low AFW pump suction pressure signal and an actuation signal are present. Auxiliary feedwater pumps can also draw from an AFWS storage tank, the service water system, and the condenser hotwell. Pump discharge typically passes through a common header before entering the piping to either the main feedwater lines or directly to the SGs. At least one AFW line exists for each main feedwater line. Flow control in each AFW line is established by a flow-control valve. Separate engineered safety feature(s) quality power subsystems and control air subsystems serve each pump and its associated valves.

The following systems interface with the AFWS:

- main steam system
- feedwater system
- essential ac distribution system
- dc power system
- engineered safety feature(s) actuation system
- condensate system
- demineralized water system
- instrument air system
- service water system
- diesel oil system for diesel-driven AFWS pumps.

The AFWS boundary extends from the CST (normal operation) or the seismic Category I water supply (emergency operation) to the connection at either the main feedwater lines or the SGs, including all pumps, valves, piping, sensors, and control equipment. The AFWS boundary also includes the steam supplies to the AFW pump turbine, including the steam admission valve and the trip and throttle valve. The arrangement of a typical AFWS for a four-loop Westinghouse plant is shown in Figure 2.1.

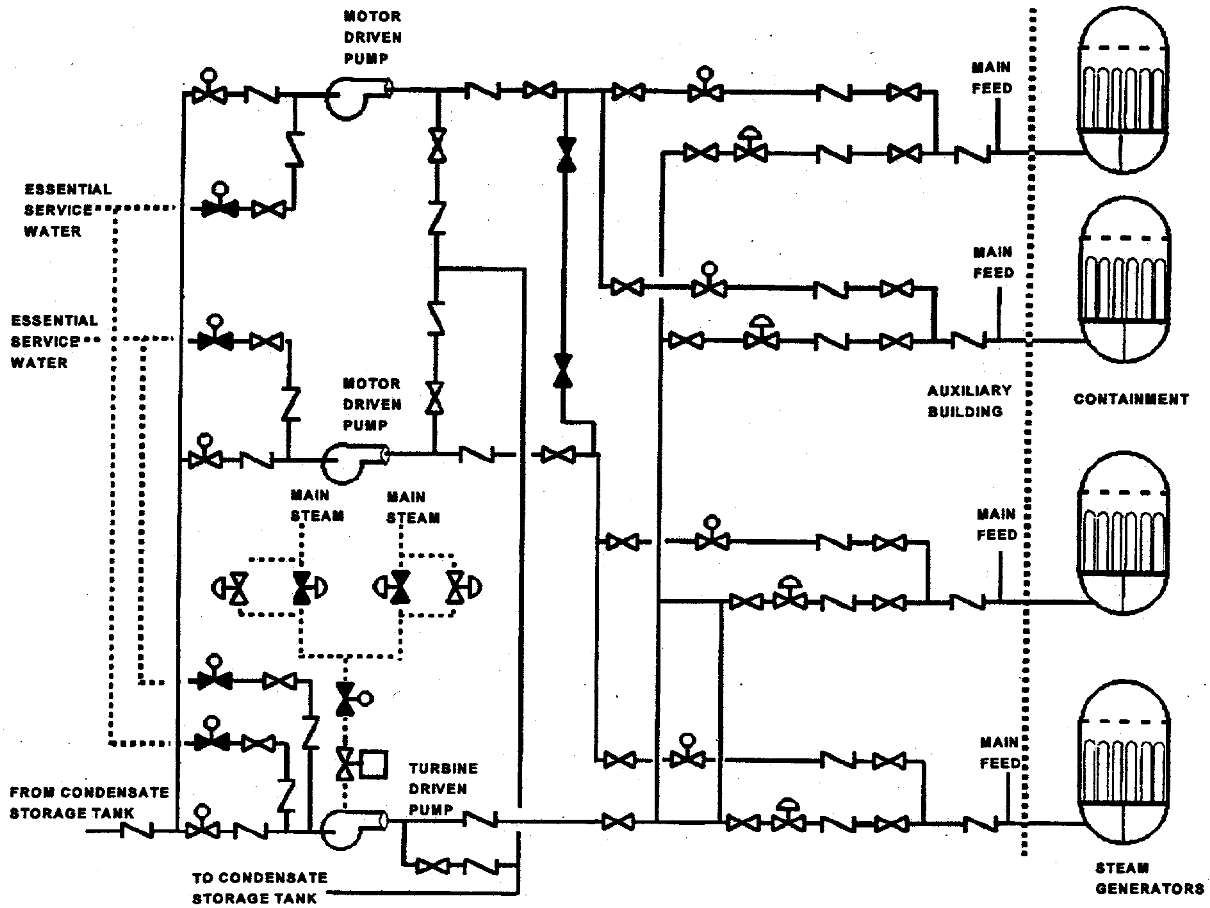

Figure 2.1. Typical AFWS for Four-Loop Westinghouse Plant

2.2 Stressors, Aging Mechanisms, and Aging Effects

The AFWS is essentially a backup system, designed to provide feedwater to the SGs under various accident scenarios. Components of the AFWS are rarely, if ever, tested under the complete set of conditions and demands associated with accident scenarios. In some cases, such testing would be deleterious to other plant systems. The overriding aging concern for the AFWS is that degradation could go undetected for components that are rarely tested or not tested under design-demand (emergency) conditions, and that this undetected degradation could cause system failure or functional degradation if the AFWS were ever called upon to perform its safety-related design functions. In particular, the instrument and control components are tested for proper actuation, as it is not prudent to test some AFWS components under emergency conditions. Some components are activated quite frequently in the course of other nonsafety-related functions for which the AFWS is used, to the point that wear on component parts becomes an aging concern.

Known AFWS stressors, the resulting aging mechanisms and aging degradation effects, and the AFWS locations where the stressors and aging mechanisms are operative are summarized in Table 2.1.

Table 2.1. Summary of Detection Capability of Current SRs

AFWS Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Methods	Addressed by STS SRs?[a]
			Pumps		
Pumps	See Table 10.1 for pumps	See Table 10.1 for pumps	See Table 10.1 for pumps	See Table 10.1 for pumps	3.7.5.2, 3.7.5.4
			Turbine		
Turbine	contaminants	wear	wear-reduction, seizure	operation	3.7.5.2, 3.7.5.4
				internal visual	no
			Valves		
Valves	See Table 7.2	See Table 7.2	See Table 7.2	See Table 7.2	3.7.5.3
Check Valves	See Table 5.2	See Table 5.2	See Table 5.2	See Table 5.2	no
Trip and Throttle Valve	operation	wear	loosening	operation	3.7.5.3, 3.7.5.4
				internal visual	no
Governor Valve	contaminants, steam	valve stem corrosion, wear, thermal expansion of valve plug	binding/lockup, contamination, stem buckling	operation	3.7.5.3, 3.7.5.4
				internal visual	no
			Piping		
walls	brackish water	corrosion, microbiological fouling	blockage, increase in frictional resistance	external visual for leakage, analysis for thinning and for increase in frictional resistance	no
	contaminants	erosion, fouling, oxidation	contamination, cracking	external visual for leakage, analysis for thinning and for increase in frictional resistance	no
	excessive fluid velocity	erosion, cavitation, wear	wall-thinning, wear-reduction	external visual for leakage, analysis for thinning	no
	operation	wear	wall-thinning	external visual for leakage, analysis for thinning	no
	pressure	fatigue	cracking, fracture	external visual for leakage, analysis	no
	steam	erosion, wear	wall-thinning, wear-reduction	external visual for leakage, analysis for wall-thinning	no

(a) Representative SRs are listed where applicable.

Table 2.1. (contd)

AFWS Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Methods	Addressed by STS SRs?[a]
walls (contd)	vibration	fatigue	loss of mechanical strength, cracking, wear-reduction	external visual for leakage, analysis	no
	water hammer	fatigue	cracking, fracture	external visual for leakage	no
flanges and gaskets	brackish water	corrosion, microbiological fouling	blockage, increase in frictional resistance	external visual for leakage, analysis for thinning, increase in frictional resistance	no
	contaminants	corrosion, fouling, oxidation	contamination, cracking	external visual for leakage, analysis for thinning, increase in frictional resistance	no
	flow	erosion, cavitation, wear	wall-thinning, wear-reduction	external visual for leakage, analysis for thinning	no
	operation	wear	wall-thinning	external visual for leakage, analysis for thinning	no
	pressure	fatigue	cracking, fracture	external visual for leakage, analysis	no
	steam	erosion	wall-thinning, wear-reduction	external visual for leakage, analysis for wall-thinning	no
	vibration	fatigue	loss of mechanical strength, cracking, wear-reduction	external visual for leakage, analysis	no
	water hammer	fatigue	cracking, fracture	external visual for leakage	no
			Instruments & Controls		
governor	contaminants	fouling	contamination, binding/lockup, drift	internal visual, hydraulic fluid analysis	no
	operation, vibration,	fatigue, wear	binding/lockup, drift, sticking open/shut	operation	3.7.5.4
seals, gaskets, other organic compounds	heat, operation, pressure, thermal-cycling, vibration	curing, embrittlement	hardening, loss of integrity, softening, cracking	external visual internal visual	no no

(a) Representative SRs are listed where applicable.

Table 2.1. (contd)

AFWS Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Methods	Addressed by STS SRs?[(a)]
connectors and overspeed trip linkages	vibration	wear	binding/lockup, drift, loosening, loss of mechanical strength, sticking open/shut	external visual	no
	operation, lack of lubrication, dirt accumulation	fatigue, fouling	binding/lockup, drift, loosening, interferences	operation	3.7.5.3
pneumatic components	humidity	oxidation, corrosion	loss of integrity	external/internal visual	no
	contaminants	fouling	blockage, sticking open/shut	internal visual	no
hydraulic components	operation	wear, abrasion, embrittlement	loss of integrity, binding/lockup, breakdown	operation	3.7.5.4
				internal visual, hydraulic fluid analysis	no
	contaminants	fouling, abrasion	increase in frictional resistance	internal visual, hydraulic fluid analysis	no
hydraulic fluid	contamination	fouling	breakdown	fluid analysis	no
	heat	oxidation	breakdown	fluid analysis	no
circuit breakers	operation	wear, galling, pitting	increase in electrical resistance, increase in response time	operation	3.7.5.3, 3.7.5.4
				resistance bridge testing	no
	contaminants	pitting, arcing, corrosion	melting, seizure, sticking shut	internal visual	no
	humidity	arcing, galling, pitting, oxidation	sticking open/shut, drift	internal visual	no
relays	ohmic heating	overheating	breakdown, melting, decrease in electrical resistance	resistance bridge testing	no
	operation	wear, pitting, galling	drift, sticking open/shut	operation	3.7.5.3, 3.7.5.4
				resistance bridge testing	no
	overvoltage/ undervoltage operation	overheating, arcing	sticking open/shut, increase in response time, decrease in electrical resistance, melting	resistance bridge testing	no

(a) Representative SRs are listed where applicable.

Table 2.1. (contd)

AFWS Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Methods	Addressed by STS SRs?[a]
contacts	ohmic heating	overheating	sticking open/shut, melting	resistance bridge testing	no
	operation	wear, pitting, galling	sticking open/shut	operation	3.7.5.3, 3.7.5.4
	overvoltage/ undervoltage operation	overheating, arcing	sticking open/shut, increase in response time, increase in electrical resistance, melting	resistance bridge testing	no
sensors	humidity	oxidation, corrosion	decrease/increase in electrical resistance, drift	operation	3.3.2.2, 3.3.2.4, 3.3.2.6
				resistance bridge test	no
	heat	overheating, differential thermal expansion	decrease/increase in electrical resistance, breakdown of insulation	operation	3.3.2.2, 3.3.2.4, 3.3.2.6
				resistance bridge test	no
	operation	wear, fatigue	seizure, breakdown, increase in electrical resistance	operation	3.3.2.2, 3.3.2.4, 3.3.2.6
				resistance bridge test	no
solenoids	operation	wear	reduction of solenoid force, increased stroke time	operation	3.7.5.3, 3.7.5.4
				internal visual	no
	contaminants	arcing, fouling	blockage, binding, lockup, sticking open/shut	internal visual	no
	humidity	corrosion, arcing, galling, pitting	decrease/increase in electrical resistance, shorting	internal/external visual	no
	environmental and ohmic heating	overheating, oxidation, thermal cycling	shorting, melting	resistance bridge testing	no
	heat	overheating, oxidation	shorting	resistance bridge testing	no

(a) Representative SRs are listed where applicable.

Representative stressors and aging mechanisms that contribute to age-related degradation include wear, corrosion, erosion, fatigue, vibration, thermal fatigue, fretting, cavitation, lubricant fouling, pitting, fretting corrosion, and crevice corrosion. Sections 5.0, 7.0, and 9.0 identify stressors, aging mechanisms, and aging degradation effects of specific components, such as check valves, motor-operated valves (MOVs), and pumps, respectively. Steam admission valve failures have been included within the failures of MOVs (see Section 7.0) because available data did not consistently indicate when a failure could be specifically attributed to the steam admission valve component.

Examples of the stressors and aging mechanisms operative for major AFWS components are as follows:

1. Pumps

- Shafts and impellers are subject to cavitation, wear, embrittlement, fatigue, erosion, and corrosion.

- Casings are subject to erosion, corrosion, fatigue, and cavitation.

- Bearings are subject to vibration, contamination, and wear.

- Packing, seals, gaskets, and fasteners are subject to wear, embrittlement, overheating, abrasion, fatigue, and erosion.

- Motors are subject to overheating and arcing.

A detailed summary of stressor and aging mechanisms for pumps is presented in Table 9.1.

2. Turbine

- Turbine lubrication is subject to contamination.

- Bearings are subject to contamination and wear.

3. Governor

- The governor mechanism is subject to contaminants, corrosion, wear, and binding.

- Governor valves are subject to binding, wear, valve stem corrosion, and contamination.

- Trip and throttle valves are subject to operational wear and binding.

- Overspeed trip mechanisms are subject to wear, binding, and contamination.

4. Valves

- Bodies are subject to corrosion, erosion, thermal stress, and fatigue.

- Seats are subject to wear, abrasion, and erosion.

- Discs/gates are subject to wear, corrosion, galling, and erosion.

- Seals and gaskets are subject to abrasion, embrittlement, erosion, and wear.

Detailed summaries of stressors and aging mechanisms for check valves and motor-operated valves are presented in Tables 5.2 and 7.2, respectively.

5. Piping

- Walls are subject to erosion, corrosion, fouling, cavitation, wear, and fatigue.

- Flanges and gaskets are subject to corrosion, erosion, fatigue, fouling, cavitation, wear, and pitting.

6. Instruments and Controls

- Components are subject to oxidation, wear, corrosion, embrittlement, fatigue, abrasion, arcing, curing, galling, overheating, pitting, and differential thermal expansion.

Also noted in Table 2.1 is whether or not a particular aging degradation effect is detected by the current Westinghouse plant surveillance requirements (SRs). A representative SR is cited for those aging effects that are detectable; more than one SR may be applicable. A potential deficiency in the SRs is identified when a particular aging effect is not detected by any existing SR (i.e., the component may experience undetected degradation). A list of recommended SRs to address the undetected degradation is presented in Section 2.6.

2.3 Degradation Detection Methods

Several methods that are effective in detecting aging degradation have been developed, either historically or in response to specific aging concerns. The specific detection methods applicable to AFWS aging degradation are identified in Table 2.1. Those methods that are useful and appropriate for inclusion in the SRs are identified in Section 2.6 as recommendations to improve or supplement the SRs.

Specific aging degradation detection methods for check valves, valves, and pumps are discussed in Sections 5.0, 7.0, and 9.0, respectively.

2.4 Evaluation of Existing Surveillance Requirements for Effectiveness in Detecting Aging Degradation

The AFWS-related SRs for the Westinghouse plant STS are summarized in Appendix 2A. The existing SRs for the AFWS focus primarily on operability concerns rather than on addressing the detection and trending of aging degradation. Major components are periodically tested at normal conditions, as opposed to demand (emergency) conditions, for function and readiness. For example, one SR requires that AFWS pumps be demonstrated to start automatically on an actuation signal;

another requires that AFWS automatic valves be demonstrated to align to their correct positions on an actuation signal; others require the measurement of plant conditions within the AFWS, such as water levels and required flows.

None of the existing SRs is intended to monitor the onset of or directly indicate the age-related degradation of the AFWS or its components. A significant percentage of AFWS failures are detected through operational abnormalities (i.e., during operation/testing); therefore, some failures are not detected by current SRs until the component is required to operate. The data that are collected during the testing of AFWS components could be augmented by additional information that would focus more on the detection and trending of aging degradation.

2.5 Evaluation of Existing Surveillance Requirements for Possible Contributions to Premature Aging Degradation

The existing SRs for AFWS are designed primarily to determine operability and not to detect and trend aging degradation. Most SRs require verification of a condition or status, such as verifying a valve position, which generally would have no aging impact. However, there are some SRs that require testing of the AFWS pumps monthly to determine if they are operable. The current low-flow test methods used to determine pump operability have proven to degrade AFWS pump operation. Nuclear Plant Aging Research studies recommend that this test interval be increased to quarterly rather than monthly to reduce the rate of test-related pump degradation while maintaining the ability to detect potential age-related degradation (Kueck 1993).

2.6 Recommendations to Improve or Supplement Surveillance Requirements

2.6.1 Recommendations from the NPAR Aging Assessments

The following recommendations address aging issues in the SRs, making them more effective in detecting, trending, and monitoring AFWS degradation before failure. These recommendations are suggested for incorporation into SRs for risk-significant and prioritized AFWS components.

In addition to the recommended individual tests and examinations, a periodic comprehensive test that encompasses the entire AFWS should be performed each refueling cycle; this test should be structured such that realistic signals or, if possible, conditions activate instrumentation and control components resulting in appropriate system component reconfigurations. A test that requires multiple component interaction would provide a higher assurance of system operability. All surveillance results must be trended over time to determine AFWS aging effects and to identify potential AFWS degradation.

1. Systematic Root-Cause Analysis

A systematic method for determining the root cause of component failures was developed for the NPAR program (Jarrell et al. 1992). This methodology focuses resources on identifying and mitigating the underlying cause of failure rather than the treatment of an indicating symptom. It is recommended that a utility-specific version of this approach be incorporated into the SR framework.

2. Pumps

Pump parts, such as impellers, casings, bearings, packing, and seals should be visually examined at least once every 10 years, or whenever opened for any other reason, for evidence of wear, corrosion, erosion, vibration, binding, looseness, cavitation, overheating, thermal/lubrication degradation, leakage, cracks, or breaks. Monitoring of motor current, motor power, turbine power, and rotational speed should be performed at least quarterly; pump flow should be monitored when tested at design (emergency) conditions, where plant operating conditions allow. Pump test results should be trended over time to note potential degradation and should include the measurement of pump suction pressure, discharge pressure, discharge flow, recirculation flow, flow to each SG, turbine inlet pressure, and pump speed.

As an adjunct, associated valves should be verified to be in their correct position during any testing. Immediately before any normal pump start, the absence of a binding condition of the rotor should be verified. Turbine auxiliaries, including the governor control system, trip and throttle valves, and level control valves, should be calibrated and tested under full-flow, demand (emergency) conditions each refueling cycle. Additional information should be recorded during routine testing, such as bearing temperature and vibration, stuffing box temperature, rotor axial position, motor amps and voltage, and motor winding temperature. Pump/motor bearings and rotors should also be subjected to vibration monitoring, coincident with pump testing, with attendant analysis and trending, to demonstrate that bearing and rotor vibration is at acceptable levels.

The head-capacity curve should be rerun once every refueling cycle, as curve deterioration is an indication of degradation of pump internals. Testing should be optimized to reduce testing of components that have historically not been major contributors to AFWS degradation and for which current testing provides little useful information, while focusing attention on those components that have more aging significance. This would aid in verifying the ability of pumps to function under design-basis (emergency) conditions and in reducing the related problem of overtesting that leads to worn components and degraded conditions. The aging studies strongly recommended that a flow rate and discharge head that correspond to a full-flow test be permitted by the technical specifications. Testing at low flows causes hydraulic instabilities that are detrimental to system pumps (Kueck 1993).

3. Valves

Valve seats, discs/gates, swing arms, and stuffing boxes should be visually examined once every other refueling cycle (as recommended by Section 7.0), or whenever opened for any other reason, for evidence of pitting, wear, binding, cracking or other forms of aging degradation. Isolation valves should be tested at pressure, rather than at a percentage of pressure. Test results should be trended over time to note potential degradation.

Additional information should be recorded during routine testing, such as motor current signature analysis of motor-operated valves and position indicator functional verification. Some required testing (e.g., stroke time testing) may be of limited value. This issue is being addressed by the U.S. Nuclear Regulatory Commission (NRC); any resulting testing reduction will be a positive change (e.g., less accumulated wear to valve seats will occur). Selected valves, such as check valves in mini-flow lines, which are activated so frequently that their potential for wear and degradation is greater, should be monitored to detect disc flutter. Methods for detecting aging of check valves are described in Section 5.0.

4. Piping

The piping from all suction sources should be examined and monitored using ultrasonic wall-thickness testing at each refueling outage to ensure system integrity, as some sources are subject to piping dead-legs that can develop undetected corrosion, cracking, or other degradation due to biofouling or plugging. Piping wall-thickness should be verified to meet minimum design requirements. Piping should be subjected to demand (emergency) pressures at least every refueling cycle and evaluated for condition and leakage.

5. Instruments and Controls

Studies have shown that many safety-related design functions are not verified to be operable using existing SR procedures. A thorough review of safety system logic should be undertaken to identify and document all logic functions included in plant-specific SRs. When the reviews and SR procedure revisions are complete, comprehensive testing of the entire safety-related control function, from sensor to end component action, should be performed at each refueling outage.

Older plants will have to be evaluated on a case-by-case basis to determine the applicability of this recommendation. Excessive reliance on jumpers or circuit modifications to accomplish the task of testing all safety-related functions may potentially reduce the reliability of the safety system. In these cases, the recommendation would not be applicable.

2.6.2 Implementing Suggested Recommendations

A list of suggested SRs for the AFWS with associated surveillance frequencies to implement the recommendations from the NPAR aging assessments is provided in Table 2.2. These recommended SRs address the potential for undetected AFWS component degradation that was identified in Table 2.1, except for those effects with a very low probability of failure of the component, or those that are more appropriately addressed by an effective maintenance program.

An SR is not specified in Table 2.2 for each individual AFWS component; rather, the individual degradation detection methods that apply to a particular degradation effect on a component are grouped to form a generically stated SR. For example, each visual examination that is deemed appropriate to detect a potential undetected degradation effect, as reflected in Table 2.1, is combined into a single recommended SR in Table 2.2. Each of these generic SRs would then be expanded by writing them for AFWS components throughout the STS in a form consistent with that of existing SRs, as identified in Appendix 2A.

Table 2.2. Surveillance Requirement Recommendations to Detect and Trend AFWS Aging Degradation

Surveillance Requirement	Frequency of Action
Visually examine pump components for evidence of wear, corrosion, erosion, vibration, binding, looseness, cavitation, overheating, thermal/lubrication degradation, leakage, cracks, or breaks.	Every 10 years or whenever open (one pump every third refueling outage)
Trend motor current, motor power, turbine power, and rotational speed.	92 days
Trend pump parameter during system operational testing.	18 months
Visually examine valve components for evidence of excessive degradation or blockage.	36 months or whenever open
Trend parameters that demonstrate that flow in the AFWS piping does not show evidence of excessive flow degradation.	18 months

Appendix 2A

Summary of Auxiliary Feedwater System Surveillance Requirements from the Westinghouse STS

SR Number	Surveillance Requirement	Frequency	Detects Aging Degradation?
Valve Position			
3.7.5.1	Verify each AFWS valve in each flowpath, including steam supplies, is in the correct position.	31 days	no
AFW System Operability			
3.7.5.2	Verify the developed head of each AFWS pump is $\geq$ the required developed head.	31 days, staggered test basis	yes
3.7.6.1	Verify the CST level is $\geq$ 110,000 gal.	12 hours	no
Action on Actuation Signal			
3.7.5.3	Verify each AFWS automatic valve actuates to the correct position on an actual or simulated actuation signal when in MODE 1, 2, or 3.	18 months	yes
3.7.5.4	Verify each AFWS pump starts automatically on an actual or simulated actuation signal when in MODE 1, 2, or 3.	18 months	yes
Flow Path Alignment			
3.7.5.5	Verify proper alignment of the required AFWS flow paths by verifying flow from the CST to each steam generator.	Before entering MODE 2, when unit has been in MODE 5 or 6 for > 30 days	no

3.0 Battery Chargers and Inverters

Battery chargers and inverters perform vital safety functions, such as supplying instrument and control power for reactor plant monitoring and protection. Battery chargers provide an interface between the alternating current (ac) and direct current (dc) systems by rectifying an ac input to a dc output for float-charging the associated batteries and supplying power to complementary loads. Inverters are used both to invert dc power supplies into ac power and for an uninterruptable source of ac power to plant essential and nonessential loads. Typical loads supplied by the inverter are

- process computer
- neutron monitoring
- scram and engineered safety feature(s) actuation systems
- emergency communications and lighting
- radiation monitoring
- control room panels
- reactor vessel level monitoring.

Operating experience data have shown that inverter failure has resulted in plant transients, reactor scrams, and safety system inoperability. Depending on the design, battery chargers and inverters may be exposed to electrical transients or high-temperature environments, which lead to age-related degradation. The operability of chargers and inverters could be improved through an increased focus on mitigating the effects of aging.

Nuclear Plant Aging Research (NPAR) studies of battery chargers and inverters were conducted by Brookhaven National Laboratory (Gunther et al. 1986; Gunther et al. 1987). These studies provided the technical basis for the standard technical specification (STS) aging evaluation. Additional information was obtained from Blahnik et al. (1992).

3.1 Battery Chargers and Inverters Description and Boundaries

The boundaries and relationships of chargers and inverters are illustrated in Figure 3.1.

3.1.1 Battery Chargers

Battery chargers are typically supplied from a 480 voltage alternating current (VAC) source, with the output connected to a 125 voltage direct current (VDC) bus. The charger boundary includes the connecting feeder breaker to the 480 VAC source and the connecting output breaker to the dc bus. Included between these two points are the electronic and nonelectronic components within the charger enclosure, the associated instrumentation, control, and protective devices, including meters, relays, fuses, switches, and circuit breakers.

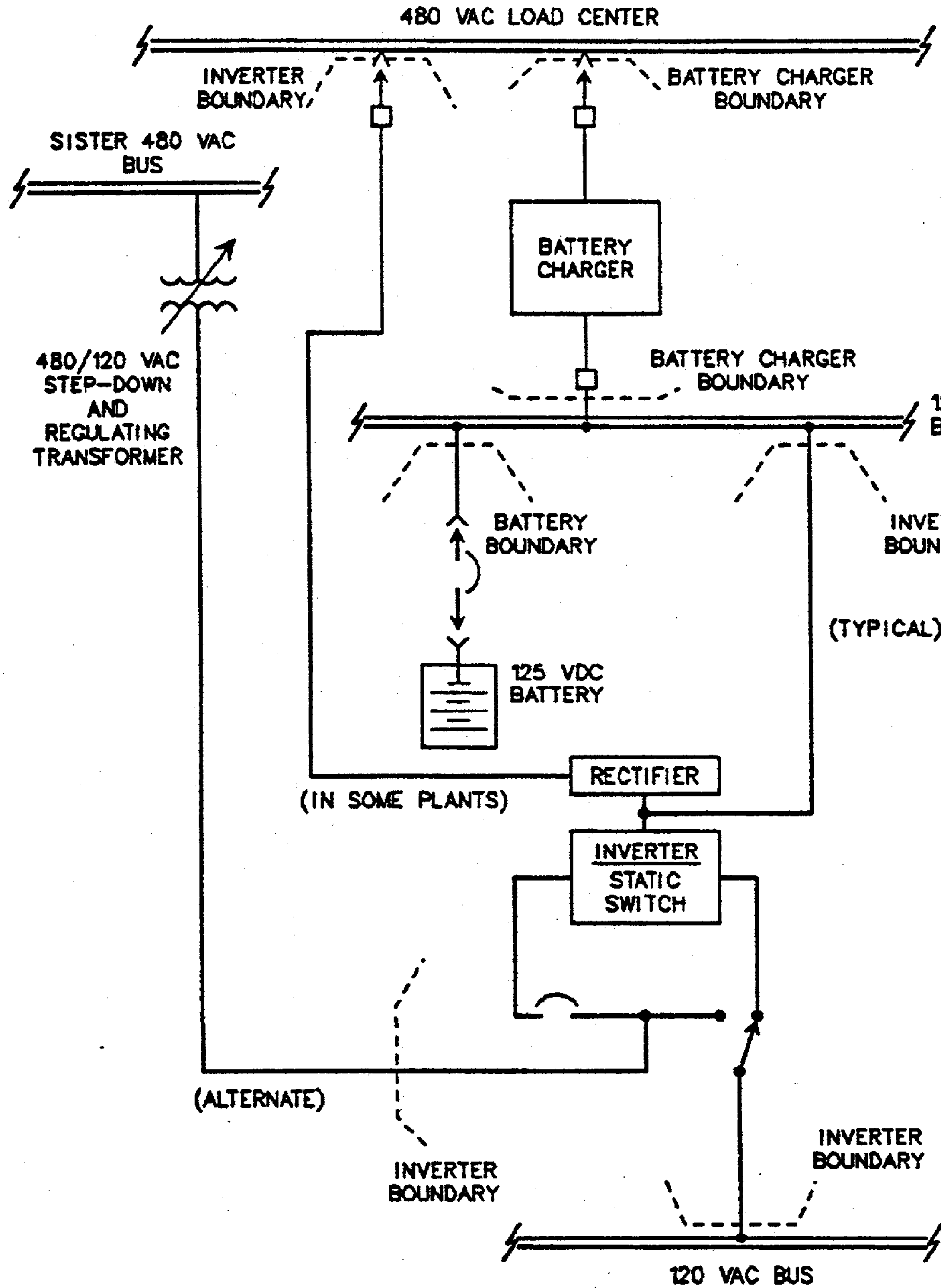

Figure 3.1. Typical Battery Charger and Inverter System

3.1.2 Inverters

Inverters typically have two power sources: rectified ac power and the dc bus. The output is routed to the distribution panels through a static switch, which will automatically select an alternative power source should the inverter fail. The inverter boundary includes a 480 VAC feeder breaker normal supply, a 125 VDC emergency supply breaker, and the distribution panel feeder breaker. Between these points are the electronic and nonelectronic components within the inverter unit, rectifier, and transfer switch, as well as the associated instrumentation, control, and protective devices, including meters, relays, fuses, switches, and circuit breakers.

3.2 Stressors, Aging Mechanisms, and Aging Effects

Known battery charger and inverter stressors, the resulting aging mechanisms and aging degradation effects, and the locations where the stressors and aging mechanisms are operative are summarized in Table 3.1 for the major components. The stressors that were reported by Gunther et al. (1986) as having a high probability of occurrence in age-related failure in battery chargers/inverters are overheating and vibration. Overheating causes loss of capacitance for both electrolytic and oil-filled capacitors, short or open circuits in the silicon-controlled rectifier and thermal degradation of the potentiometer. Vibration causes loose or open circuits in printed circuit boards.

Another major contributor to aging is electrical transients (e.g., voltage spikes, high or low voltages, or momentary power interruptions). These transients can be caused by lightning, motor starts, circuit breaker operation, and electrical faults. Transients are common in nuclear plants, where the use of uninterruptable power systems protects against most external transients, but does not protect against all internally generated transients. To the extent practical, utilities should attempt to eliminate the severity and frequency of controllable electrical transients. Other major aging mechanisms include mechanical wear, vibration, corrosion, and loosened connections.

Also noted in Table 3.1 is whether or not a particular aging degradation effect is detected by the current Westinghouse plant surveillance requirements (SRs). A representative SR is cited for those aging effects that are detectable; more than one SR may be applicable. A potential deficiency in the SRs is identified when a particular aging effect is not detected by any existing SR (i.e., the component may experience undetected degradation). Recommended SRs to address the undetected degradation are listed in Section 3.6.

3.3 Degradation Detection Methods

Several methods that are effective in detecting aging degradation have been developed, either historically or in response to specific aging concerns. The specific detection methods that are applicable to battery charger/inverter aging degradation are identified in Table 3.1. Those methods that are useful and appropriate for inclusion in the SRs are identified in Section 3.6 as recommendations to improve or supplement the SRs.

Table 3.1. Summary of Detection Capability of Current SRs[a]

Battery Charger and Inverter Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Method	Addressed by STS SRs?[b]
circuit breaker	contamination, dirt, lubrication hardening	bearing wear	increase in friction, binding	operational testing, visual inspection	no
	operation	metal fatigue, embrittlement, insulation cracking	reduction of trip coil force	operational testing, visual inspection	no
	humidity	oxidation and pitting of contact surfaces	loss of continuity across contacts	resistance testing	no
fuse	operation	equipment load cycling, metal fatigue	loss of circuit continuity	resistance testing	no
	high environmental temperature, overheating	melting of link	fuse failure	resistance testing, temperature monitoring	no
relay	humidity	oxidation and pitting of contact surfaces	loss of continuity across contacts	resistance testing, visual inspection	no
	operation, electromechanical action	wear of fine wires	loss of continuity through coil wires and open circuit	operational testing, resistance testing	no
electrolytic capacitors	overheating	loss of electrolyte	loss of capacitance	visual inspection, voltage testing, temperature monitoring	no
	operation	vibration	lead failure and open circuit	voltage testing	3.8.4.6
oil-filled capacitors	overheating	dielectric breakdown	loss of capacitance	visual inspection, voltage testing	no
	operation	vibration	lead failure and open circuit	operational testing, voltage testing	3.8.4.6
magnetics (transformer inductor)	overheating, thermal-cycling, low temperature	insulation cracking, moisture seal cracking	short circuit	voltage testing, temperature monitoring	no
	overvoltage	deterioration of insulating material	short circuit	voltage testing	no
	operation	vibration	shunting change, connecting wire fracture, change in inductance	operational testing	3.8.4.6
semiconductor devices, silicon-controlled rectifier diodes, transistors	overheating	overvoltage, over-current due to transients.	short or open circuit	voltage testing, temperature monitoring	no

(a) Reference Table 4.6, NUREG/CR-4564 (Gunther et al. 1986).
(b) Representative SRs are listed where applicable.

Table 3.1. (contd)

Battery Charger and Inverter Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Method	Addressed by STS SRs?[b]
resistor	vibration	lead failure	open circuit	resistance testing	no
	overheating	decrease in resistance value	circuit degradation	resistance testing, temperature monitoring	no
printed circuit boards	temperature cycling	cracking of circuit lines-bonding strength failure	change in output	operational testing, temperature monitoring, waveform of gate-drive circuit	no
	humidity, contaminants	corrosion	increase in resistance, change in output, open circuit	resistance testing	no
	operation	vibration	loose connection	operational testing	no
surge suppressor	overheating	semiconductor barrier breakdown	overvoltage, overcurrent, short circuit	temperature monitoring	no
connectors	installation stresses, vibration	fatigue of terminal wires	open or short circuits	visual inspection	no
meters	contamination, dirt	bearing friction	stuck meter	visual inspection, calibration testing	no
	overheating	coil insulation degradation	response failure	calibration testing, temperature monitoring	no
switch (including automatic transfer switch)	contaminants	corrosion/pitting	loss of continuity across contacts	visual inspection	no
	operation	mechanical wear, fatigue	binding, automatic transfer failure	operational testing	no
potentiometer	thermal degradation	loss of continuity across wiper arm and coil	open or short circuit	resistance testing, visual inspection	no

(a) Reference Table 4.6, NUREG/CR-4564 (Gunther et al. 1986).
(b) Representative SRs are listed where applicable.

3.4 Evaluation of Existing Surveillance Requirements for Effectiveness in Detecting Aging Degradation

The SRs for battery chargers/inverters for the Westinghouse plant STS are summarized in Appendix 3A. The existing SRs focus primarily on operability concerns and not on addressing the detection and trending of aging degradation. For example, one SR requires that battery chargers be demonstrated to supply greater than a specified amperage at a specific voltage for a time interval; others require verification of correct inverter voltage, frequency, and alignment to required ac vital busses. None of the existing SRs is intended to monitor the onset of or directly indicate the age-related degradation of the battery chargers and inverters.

3.5 Evaluation of Existing Surveillance Requirements for Possible Contributions to Premature Aging Degradation

The existing SRs for battery chargers/inverters are designed primarily to determine operability, which generally should have no aging impact. Thus, the existing SRs for battery chargers/inverters do not contribute to aging in that the test methods and the frequency of testing do not cause premature aging degradation. However, electrical transients associated with the SR-mandated start and run of the emergency diesel generators have caused inverter failures.

3.6 Recommendations to Improve or Supplement Surveillance Requirements

3.6.1 Recommendations from the NPAR Aging Assessments

The NPAR studies of battery chargers/inverters have developed additional recommendations that address age-related issues. The following recommendations address aging issues in the SRs, making them more effective in detecting, trending, and monitoring battery charger/inverter degradation before failure. These recommendations are suggested for incorporation into SRs for battery chargers and inverters.

1. Examinations

- Battery chargers and inverters should have all accessible connections and components examined every refueling cycle, with the inverter deenergized, for indications of age-related degradation due to overheating, for loose electrical and mechanical connections, and for cleanliness.

- Cabinet temperatures should be monitored monthly and in conjunction with testing for indication of overheating. Silicon-controlled rectifier junction temperatures should be monitored in conjunction with testing for indication of overheating.

- The electrical supply to chargers and inverters should be monitored continuously each refueling cycle for the presence of potentially damaging electrical transients. Cabinet supports, component mounting, and wire and cable connectors should be examined every refueling cycle to ensure that they comply with the original design requirements for seismic mounts.

- Relays and breakers should be examined every refueling cycle for such age-related degradation as carbon deposits and degraded coils.

2. Tests

Online (energized and at rated load)

- Battery chargers should have the ac ripple voltage on the dc supply to the inverter measured quarterly.

- Inverters should have the output voltage waveform and the voltage across the commutating capacitors monitored quarterly.

- Automatic transfer switches should be function-tested every refueling cycle for correct operation.

- Inverters should be capacity-tested every refueling cycle to ensure performance of their intended functions when required.

Offline (deenergized)

- Battery chargers and inverters should have the capacitance value of their filter capacitor banks measured and compared to previous and nameplate data every refueling cycle. A five to 10 percent decrease in capacitance value is indicative of capacitor end-of-life.

- Internal protective devices (e.g., shutdown relays, trips, and alarms) should be calibrated every refueling cycle.

3.6.2 Implementing Suggested Recommendations

A list of suggested SRs for battery charger/inverter components with associated surveillance frequencies to implement the recommendations from the NPAR aging assessments is provided in Table 3.2. These recommended SRs address the potential for undetected battery charger/inverter component degradation that was identified in Table 3.1, except for those effects with a very low probability of failure of the component or those that are more appropriately addressed by an effective maintenance program.

An SR is not specified in Table 3.2 for each individual battery charger/inverter component; rather, the individual degradation detection methods that apply to a particular degradation effect on a component are grouped to form a generically stated SR. For example, each visual examination that is deemed appropriate to detect a potential undetected component degradation effect, as reflected in Table 3.1, is combined into a single recommended SR in Table 3.2. Each of these generic SRs would then be expanded by writing them for battery charger/inverter components throughout the STS in a form consistent with that of existing SRs, as identified in Appendix 3A.

Table 3.2. Surveillance Requirement Recommendations to Detect and Trend Battery Charger and Inverter Aging Degradation

Surveillance Requirement	Frequency of Action
Monitor and trend cabinet temperatures for indication of overheating.	31 days
Visually inspect cabinets for cleanliness, component overheating, loose electrical and mechanical connections, and evidence of corrosion that may affect the operation of the system.	92 days
Trend the ac ripple voltage from the battery charger. Verify that the percent ripple does not exceed 20% of root-mean squared.	92 days
Trend the inverter output voltage waveform and the voltage across the commutating capacitors.	92 days
Functionally test the automatic transfer switches.	18 months
Calibrate internal protective devices associated with the equipment-monitoring system.	18 months
Trend the capacitance values of the filter-capacitor banks.	18 months

Appendix 3A

Summary of Battery Charger and Inverter Surveillance Requirements from the Westinghouse STS

SR Number	Surveillance Requirement	Frequency	Detects Aging Degradation?
	Charger		
3.8.4.6	Verify each battery charger supplies ≥ (400) amps at ≥ (125) V for ≥ [eight] hours.	(18 months)	yes
	Inverter		
3.8.7.1	Verify correct inverter voltage, (frequency,) and alignment to required ac vital buses.	7 days	no
3.8.8.1	Verify correct inverter voltage, (frequency,) and alignments to required ac vital buses.	7 days	no
	Breaker Alignment and Bus Voltage Checks		
3.8.9.1	Verify correct breaker alignments and voltage to (required) ac, dc, and ac vital bus electrical power-distribution subsystems.	7 days	no
3.8.10.1	Verify correct breaker alignments and voltage to required ac, dc, and ac vital bus electrical power-distribution subsystems.	7 days	no

4.0 Class 1E Power Systems

Class 1E is the safety classification of the electrical equipment and systems that are essential to emergency reactor shutdown, containment isolation, reactor core cooling, and containment and reactor heat removal, or are otherwise essential in preventing a significant release of radioactive material to the environment. All safety-related equipment and systems are designated as Class 1E. Nonsafety-related loads are also supplied from Class 1E power busses during normal operation. These nonsafety-related loads are shed whenever an emergency condition exists that requires actuation of the engineered safeguards equipment. The Class 1E power system is subject to a range of age-related degradation, as described in Section 4.2.

Nuclear Plant Aging Research (NPAR) studies by Meyer and Edson (1990) were conducted to evaluate various aging mechanisms applicable to the Class 1E power system components. A study by Sharma (1992) describes the monitoring and detection methods of aging for the Class 1E power system. Additional information was obtained from Blahnik et al. (1992).

4.1 Class 1E Power System Description and Boundaries

The boundaries and relationships of a Class 1E power system for a typical nuclear power plant are illustrated in Figure 4.1. This study does not include the unit generators and their busses, generator breaker, startup transformers, connections to the switchyard, transmission lines, or the offsite transmission network. The dividing point between the preferred power supply and the Class 1E power system is the breakers feeding the 4160 V bus.

The Class 1E power system includes the following systems:

- alternating current (ac) power systems
  - ac essential power
  - vital instrument ac power
  - essential lighting power
- direct current (dc) power systems
  - vital dc power
  - emergency power.

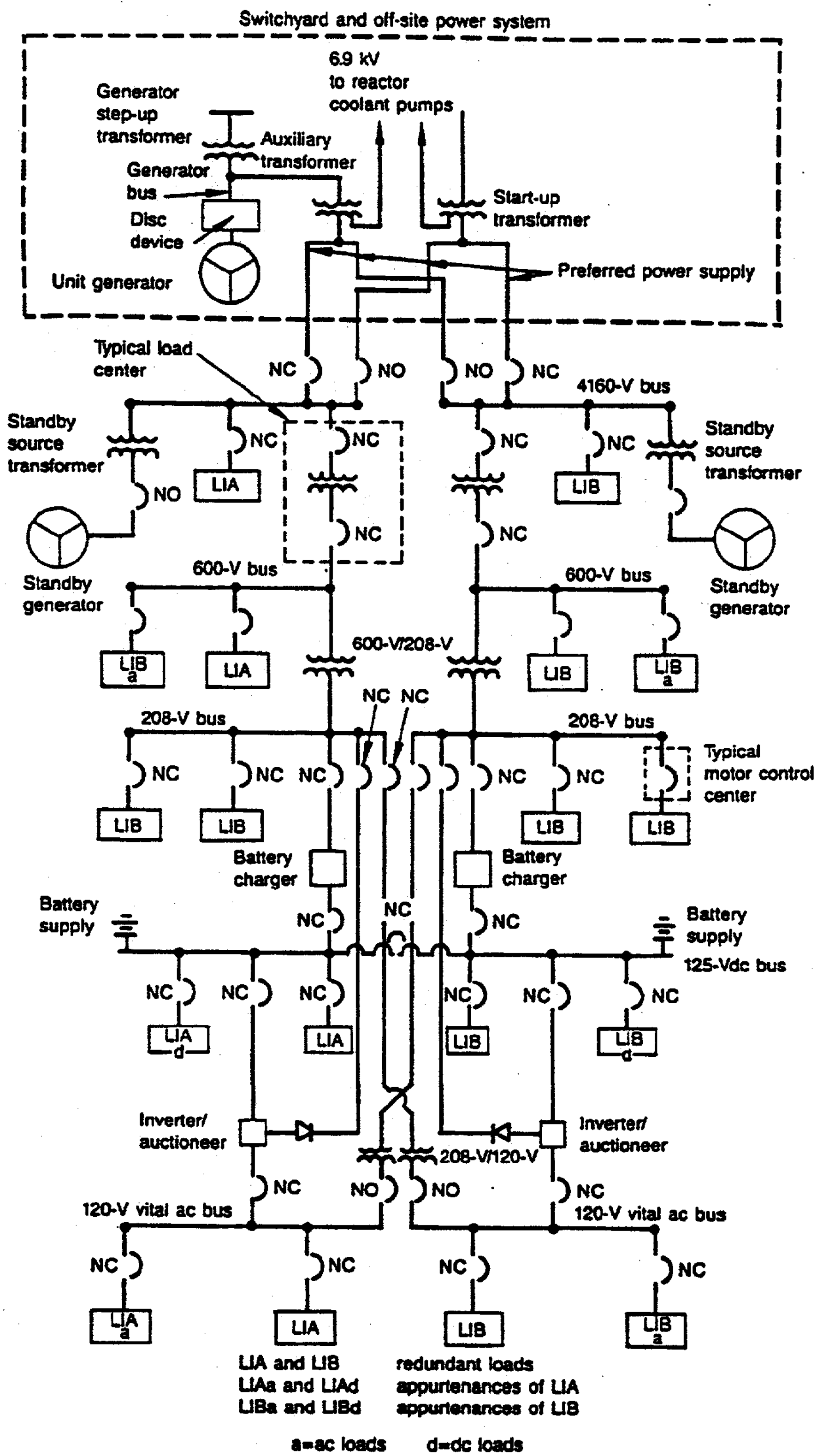

Figure 4.1. Typical Class 1E Power System

The ac power system is that part of the auxiliary electric power system that supplies safety-related loads between 4160 V and 208 V. The ac power system normally operates to support other plant systems under both normal and accident conditions, and is in turn supported by the dc power system. The dc power system provides control power for feeder breakers on the main feeder busses, 6.9 kV and 4160 kV load busses, and load-centered feeder breakers.

The ac power distribution system includes at least two 4160 V busses and is a dual-train cascading bus system. Under normal operating conditions, the ac power system receives power from the unit generator through the auxiliary transformer. Under emergency conditions, after nonessential loads are shed, the onsite power source (usually diesel generators) supplies emergency power through the standby source transformer to the 4160 V bus. Components of this system include circuit breakers, relays, contacts, busses, transformers, motor control centers, switchgear, cables, raceways, and instrumentation.

The dc power distribution system interfaces with the vital ac power system. Components of this system include batteries, battery chargers, inverters, switch assemblies, circuit breakers, control relays, diodes, cables, and instrumentation.

4.2 Stressors, Aging Mechanisms, and Aging Effects

Known Class 1E Power System stressors, the resulting aging mechanisms and aging degradation effects, and the locations where the stressors and aging mechanisms are operative are summarized in Table 4.1 for the major components. Also noted in Table 4.1 is whether or not a particular aging degradation effect is detected by the current Westinghouse plant surveillance requirements (SRs). A representative SR is cited for those aging effects that are detectable; more than one SR may be applicable. A potential deficiency in the SRs is identified when a particular aging effect is not detected by any existing SR (i.e., the component may experience undetected degradation). Recommended SRs to address the undetected degradation are listed in Section 4.6.

Major aging mechanisms for Class 1E power systems include corrosion, high temperature, fatigue, arcing, abrasions, oxidation, cracking, and embrittlement. Inadequate maintenance can also have negative impacts. While the exact impact of the mechanisms in the various plants are plant-specific, the components failing most often are breakers, batteries, and transformers. A detailed listing of the aging mechanisms that are active on Class 1E components and systems follows.

Table 4.1. Summary of Detection Capability of Current SRs

Class 1E Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/Suggested Degradation Detection Method	Addressed by STS SRs?[a]
breaker hardware	contaminants (dirt, etc.)	abrasion/galling	binding/lockup of operating mechanisms	operational testing, infrared thermography, multiple signal analyses, visual inspection	no
	operation	wear	loosening operating mechanisms	operational testing, infrared thermography, multiple signal analyses, time response test, visual inspection	no
		fatigue	loss of mechanical strength	analysis	no
breaker relays and control circuit	operation	wear	binding/loosening	trip timing test, infrared thermography, multiple signal analyses, visual inspection	no
		fatigue	cracking/fracture	analysis, infrared thermography, multiple signal analyses, visual inspection	no
		pitting	increase in electrical resistance	voltage/resistance testing, infrared thermography, multiple signal analyses	no
		arcing	melting/sticking closed	operational testing, voltage/resistance testing, infrared thermography, multiple signal analyses	no
	contaminants (dirt etc.)	abrasion/galling	binding/lockup sticking open/shut	operational testing, infrared thermography, multiple signal analyses, visual inspection	no
		arcing	melting/decrease in electrical resistance	voltage/resistance test, infrared thermography, multiple signal analyses, visual inspection	no
	humidity	oxidation	increase in electrical resistance	voltage/resistance test, infrared thermography, multiple signal analyses	no

(a) Representative SRs are listed where applicable.

Table 4.1. (contd)

Class 1E Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/Suggested Degradation Detection Method	Addressed by STS SRs?[(a)]
transformers	high/ low temperature or humidity	magnetic core deformation, moisture seal cracking, corrosion	open circuit, winding-to-winding short circuit, winding-to-case short circuit, unusually high sound level, oil dielectric strength reduced	test dielectric oil strength, visual inspection, audio monitoring, temperature monitoring, voltage testing, infrared thermography	no
	high voltage	winding insulation degradation, corona, overheating	open circuit, winding-to-winding short circuit, winding-to-case short circuit, gassing, sludge formation	visual inspection, voltage testing, temperature monitoring, infrared thermography, monitor gas accumulation	no
	vibration	connection lead fracture, insulation breakdown	open circuit, winding-to-winding short circuit, winding-to-case short circuit, change in impedance, hot spots	voltage testing, vibration monitoring, infrared thermography	no
power and control cables	high temperature, radiation, humidity, mechanical stress abrasions	embrittlement, cracking insulation, melting	open, short to ground, or conduits-to-conductor short	voltage/resistance test, visual inspection	no
cable penetrations (seals and insulators)	high temperature, humidity	cracking	leaking	visual inspection, pressure testing	no
batteries	overcharging	excessive temperature, accelerated corrosion	reduced capacity	temperature monitoring, capacity testing	3.8.4.7, 3.8.4.8
	undercharging	buckling of plates	reduced capacity or battery failure	capacity testing	3.8.4.7, 3.8.4.8
	ripple, high-ambient temperature	excessive temperature, accelerated corrosion, embrittlement of positive terminals	reduced capacity, plate growth with eventual case cracking, battery failure	visual inspection, capacity testing, temperature monitoring	3.8.4.3, 3.8.4.7, 3.8.4.8
	electrolyte impurities	shedding of active material, corrosion of positive grid, hydrolysis	reduced capacity	electrolyte analysis, capacity testing	3.8.4.7, 3.8.4.8, 3.8.6.1, 3.8.6.2, 3.8.6.3
	dirt and moisture on cases	low resistance between terminals, low resistance to ground, oxidation and corrosion of terminals	ground faults/shorts, reduced capacity, battery failure	visual inspection, voltage/resistance testing, capacity testing	3.8.4.3, 3.8.4.5, 3.8.4.7, 3.8.4.8

(a) Representative SRs are listed where applicable.

Table 4.1. (contd)

Class 1E Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/Suggested Degradation Detection Method	Addressed by STS SRs?[(a)]
batteries (contd)	battery gases	oxidation and corrosion of terminals	reduced capacity	visual inspection, capacity testing	3.8.4.4
terminal and connections	thermal cycling	embrittlement, cracking insulation	open, short to ground	visual inspection, voltage/resistance testing, temperature monitoring	no
	installation stresses	fatigue of wire at terminals	Open or short circuit	voltage/resistance test, visual inspection	no

(a) Representative SRs are listed where applicable.

Many of the components in the Class 1E power system are common to the chargers and inverters. These common components and aging mechanisms are found in Table 4.1. The common components are

- circuit breakers
- relays
- chargers and inverters
- electrolytic and oil-filled capacitors
- magnetic components
- semiconductors.

4.3 Degradation Detection Methods

Several methods that are effective in detecting aging degradation have been developed, either historically or in response to specific aging concerns. The specific detection methods that are applicable to aging degradation of Class 1E power system are identified in Table 4.1. Those methods that are useful and appropriate for inclusion in the SRs are identified in Section 4.6 as recommendations to improve or supplement the SRs.

4.4 Evaluation of Existing Surveillance Requirements for Effectiveness in Detecting Aging Degradation

The SRs for Class 1E power systems for the Westinghouse plant standard technical specifications (STS) are summarized in Appendix 4A. The existing SRs focus primarily on operability concerns and not on addressing the detection and trending of aging degradation. None of the SRs for the ac power system has the capability to detect or monitor the onset of age-related degradation. However, the SRs for the dc power system associated with the batteries have the capability to detect and monitor the onset of the aging degradation only if the parameters are properly trended. If trended, the cell parameters, terminal voltage, and battery capacity can be used to detect degradation of the batteries.

4.5 Evaluation of Existing Surveillance Requirements for Possible Contributions to Premature Aging Degradation

1. The AC Power System

The SRs related to the ac power system were found have no detectable aging influence on the hardware. These SRs required a verification of a condition or status to determine operability and not to detect and trend aging effects.

2. The DC Power System

All SRs related to the dc power system were found to help mitigate aging or detect degradation without contributing to or accelerating aging.

4.6 Recommendations to Improve or Supplement Surveillance Requirements

4.6.1 Recommendations from the NPAR Aging Assessments

Specific NPAR studies related to the Class 1E power systems have made recommendations that address system aging problems. The following recommendations were made by Meyer and Edson (1990):

1. Inspection and monitoring of cables include a walkdown visual inspection, periodic remote monitoring of key characteristics, and temperature and radiation mapping at selected containment locations.

2. Development of advanced monitoring and surveillance methods of cables, connections, and penetrations that detect aging degradation at the incipient stage before circuit failure.

3. Continuation of the development of transformer-monitoring techniques, such as hot spot monitors and corona detection and location monitors.

Sharma (1992) recommends that detection methods, such as infrared thermography of system components (e.g., circuit breakers, relay transformers), current signature analysis, or circuit diagnostic tests be used to detect system aging (see Appendix 8D).

4.6.2 Implementing Suggested Recommendations

Suggested SRs for Class 1E power system components with associated surveillance frequencies to implement the recommendations from the NPAR aging assessments are listed in Table 4.2. These recommended SRs address the potential for undetected Class 1E power system component degradation that was identified in Table 4.1, except for those effects with a very low probability of failure of the component or those that are more appropriately addressed by an effective maintenance program.

An SR is not specified in Table 4.2 for each individual Class 1E power system component; rather, the individual degradation detection methods that apply to a particular degradation effect on a component are grouped to form a generically stated SR. For example, each visual examination that is deemed appropriate to detect a potential undetected component degradation effect, as reflected in Table 4.1, is combined into a single recommended SR in Table 4.2. Each of these generic SRs would then be expanded by writing them for Class 1E power system components throughout the STS in a form consistent with that of existing SRs, as identified in Appendix 4A.

Table 4.2. Surveillance Requirement Recommendations to Detect and Trend Class 1E Power Systems Aging Degradation

Surveillance Requirement	Frequency of Action
Walkdown visual examination of cables for evidence of degradation resulting from temperature, moisture, radiation, or other environmental effects.	18 months
Periodic remote monitoring of key cable characteristics for evidence of degraded performance.	18 months
Periodic examination of cable penetrations, including leak detection, for evidence of degraded performance (e.g., a short in an adjoining cable).	18 months
Temperature and radiation monitoring of selected containment cable locations for indications of potentially degrading environmental conditions.	92 days
Trend key transformer characteristics (i.e., visual or audio monitoring, monitoring oil and hot spot temperatures, oil levels, generated gas accumulation, dielectric strength of oil) for evidence of degraded performance.	7 days
Visual examination of circuit breakers and relays for evidence of dirt, contaminants, hardened grease, and wear.	18 months
Periodic testing of circuit breakers and relays for evidence of degraded performance.	18 months
Perform meggering and Doble testing, combined with advanced monitoring methods, as available, to verify electrical insulation properties for evidence of degradation.	18 months
Perform current signature analysis of selected components (e.g., circuit breakers) for more accurate indication of degraded performance.	92 days
Perform circuit diagnostic tests of selected components (e.g., conductors) for more accurate indication of degraded performance.	92 days
Perform infrared thermography of selected items (e.g., batteries, circuit breakers, relays, transformers) for more accurate indication of degraded performance.	92 days

Appendix 4A

Summary of Class 1E Power System Surveillance Requirements from a Westinghouse STS

SR Number	Surveillance Requirement	Frequency	Detects Aging Degradation?
	Battery		
3.8.4.1	Verify battery terminal voltage is ≥ (129) V on float charge.	7 days	
3.8.4.2	Verify no visible corrosion at terminals and connectors. **OR** Verify connection resistance (is ≤ (1E-5 ohm) for inter-cell connections, ≤ (1E-5 ohm) for inter-rack connections, ≤ (1E-5 ohm) for inter-tier connections, and ≤ (1E-5 ohm) for terminal connections).	92 days	yes
3.8.4.3	Verify cells, cell plates, and battery racks show no visual indication of physical damage or abnormal deterioration.	(12) months	yes
3.8.4.4	Remove visible terminal corrosion, verify cell-to-cell and terminal connections are clean and tight and are coated with anti-corrosion material.	(12) months	yes
3.8.4.5	Verify connection resistance (is ≤ (1E-5 ohm) for inter-cell connections, ≤ (1E-5 ohm) for inter-rack connections, ≤ (1E-5 ohm) for inter-tier connections, and ≤ (1E-5 ohm) for terminal connections).	(12) months	yes
3.8.4.7	Verify battery capacity is adequate to supply, and maintain in OPERABLE status, the required emergency loads for the design duty cycle when subjected to a battery service test.	(18 months)	yes
3.8.4.8	Verify battery capacity is ≥ (80)% of the manufacturer's rating when subjected to a performance discharge test.	60 months **AND** –NOTE– Only applicable when battery shows degradation or has reached (85)% of expected life --------- 12 months	yes
3.8.6.1	Verify battery cell parameters meet Table 3.8.6-1, Category A limits.	7 days	yes
3.8.6.2	Verify battery cell parameters meet Table 3.8.6-1, Category B limits.	92 days **AND** Once within 24 hours after a battery discharge < (110) V **AND** Once within 24 hours after a battery overcharge > (150) V	yes

SR Number	Surveillance Requirement	Frequency	Detects Aging Degradation?
3.8.6.3	Verify average electrolyte temperature of representative cells is $\geq$ (60)°F.	92 days	yes
Breaker Alignment and Bus Voltage Verification			
3.8.1.1	Verify correct breaker alignment and indicated power availability for each (required) offsite circuit.	7 days	no
3.8.9.1	Verify correct breaker alignments and voltage to (required) ac, dc, and ac vital bus electrical power distribution subsystems.	7 days	no
3.8.10.1	Verify correct breaker alignments and voltage to (required) ac, dc, and ac vital bus electrical power distribution subsystems.	7 days	no
Transfer of Power to Alternate Source			
3.8.1.8	Verify (automatic (and) manual) transfer of ac power sources from the normal offsite circuit to each alternate (required) offsite circuit.	(18 months)	no
3.8.1.11	Verify on an actual or simulated loss of offsite power signal: a. Deenergization of emergency buses; b. Load-shedding from emergency buses; (Balance of this SR under the Engineered Safety Feature Diesel Generator section.)	(18 months)	no
3.8.1.12	Verify on an actual or simulated Engineered Safety Feature actuation signal each diesel generator auto-starts from standby condition and: (a through d are covered in the Engineered Safety Feature Diesel Generator section.) e. Emergency loads are energized (or auto-connected through the automatic load sequencer) to the offsite power system.	(18 months)	no
3.8.1.19	Verify on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated Engineered Safety Feature actuation signal: a. Deenergization of emergency buses; b. Load-shedding from emergency buses; (Balance of this SR under the Engineered Safety Feature Diesel Generator section.)	(18 months)	no

5.0 Check Valves

Check valves (CVs) are simple in design and function. They are used extensively within Pressurized-Water Reactor (PWR) and Boiling-Water Reactor (BWR) nuclear power plants for service in safety-related and balance-of-plant systems. The function of CVs is to passively permit flow in only one direction and to prevent flow in the opposite direction. Most CVs are self-actuating in that they require no external signal, mechanical or electrical, to open or close (one exception is testable CVs, which do not depend upon flow conditions to be tested). When fluid flow stops or tries to reverse direction, the CV immediately closes to prevent backflow. Consequently, most CVs have no capability to be actuated except by changing flow through the valve. The performance and condition of CVs is accordingly difficult to monitor. The several types of CVs used, depending on the application and the system configuration, include swing-check, horizontal-lift, vertical-lift, piston-lift, ball, stop-check, tilting-disc, and duo-check. A summary of the usage of CVs in typical PWR and BWR systems is given in Table 5.1, which indicates the numbers and size ranges of CVs used in the various systems.

Table 5.1. Summary of CV Applications in Nuclear Power Plants

System	Number of CVs	Valve Size (inches)
BWR (typical)		
Low-pressure core spray	6 to 18	2 to 28
High-pressure coolant injection	6 to 14	4 to 24
Low-pressure coolant injection (including residual heat removal and containment spray)	8 to 22	4 to 24
Balance-of-plant systems	200 to 400	0.5 to 24
PWR (typical)		
Auxiliary feedwater	4 to 24	4 to 8
Containment spray	4 to 14	6 to 14
High-pressure coolant injection	12 to 28	2 to 4
Low-pressure coolant injection (including residual heat removal)	5 to 14	8 to 10
Balance-of-plant systems	200 to 400	2 to 6

For many years, it was believed in the nuclear industry that, as passive components, the ability of CVs to function was not subject to age-related degradation. However, CV reliability has become an issue during the last 10 years because of CV failures that have significantly affected plant operations and the availability or reliability of safety-related systems. Check valves fail to perform their intended function through failure to open, failure to close, plugged (limited or no flow), internal (reverse) leakage, and external leakage. Failures have resulted in significant maintenance efforts; can result in water hammer, overpressurization, and damage to system components; and have been largely attributed to severe degradation of internal parts, resulting from instability (i.e., flutter of internal parts) under normal plant operating conditions. Several diagnostic methods are now available for detecting CV age-related degradation.

A comprehensive Nuclear Plant Aging Research (NPAR) aging assessment of CVs has been conducted by Oak Ridge National Laboratory (Greenstreet et al. 1985). These studies identified the stressors and operative aging mechanisms for CVs and evaluated methods to detect, differentiate, and trend the resulting aging degradation. These NPAR studies provided the technical basis for the CV standard technical specification (STS) aging evaluation. Additional information on CV aging processes and detection techniques may be found in Blahnik et al. (1992) and Kalsi et al. (1988).

5.1 Check Valve Description and Boundary

For the purposes of this document, the CV is defined by three subcomponents: the body assembly, internals, and seals. Not addressed in this report are the remote external position indicator sensors or devices, as the failure of these items would not affect CV operation. Figure 5.1 is an exploded view of a typical swing CV. The CV subcomponents defined above include the following items:

- body assembly subcomponent
  - body
  - bonnet
  - fasteners
  - plugs
- internals subcomponent
  - valve seat
  - disc (obturator)
  - hanger
  - hanger pin

- locking devices

- any other internal parts

- seals subcomponent

  - seals

  - gaskets.

5.2 Stressors, Aging Mechanisms, and Aging Effects

Check valve stressors, aging mechanisms, aging effects, and the CV subcomponent locations where the stressors and aging mechanisms are operative are summarized in Table 5.2 for each major CV subcomponent. The stressors and aging mechanisms for CVs include thermal stresses, adverse environmental conditions, radiation, vibration, contamination, vibration-induced fatigue, mechanical stress abrasions, corrosion, oxidation, cracking, and embrittlement. Inadequate maintenance also can contribute to premature degradation of CVs. The overall impact of these degradation mechanisms has plant-specific applications.

Also depicted in Table 5.2 is whether or not a particular aging degradation effect is detected by the current surveillance requirements (SRs). A representative SR is cited for those aging effects that are detectable; more than one SR may be applicable. A potential deficiency in the STS is identified when a particular aging effect is not detected by any existing SR (i.e., the CV subcomponent may experience undetected degradation). A list of recommended SRs to address the undetected degradation is presented in Section 5.6. Degradation effects that are more appropriately addressed by an effective maintenance program (e.g., fastener loosening and seal cracking or distortion) are not included.

5.3 Degradation Detection Methods

Monitoring methods that are presently available for CVs can provide information that is useful to determine the presence and degree of age-related degradation (i.e., the integrity of CV internal parts). These monitoring methods use different transducers and principles of operation; thus, they provide different capabilities. The following methods to detect CV internal aging degradation were evaluated: acoustic emission monitoring, ultrasonic examination, external magnet monitoring, magnetic flux signature analysis, and radiography.

Acoustic emission monitoring uses pressure waves that are generated in one of several ways, detected by sensors, and analyzed to help to determine component condition. It is nonintrusive and can be used to monitor CV internal impacts, fluid flow, leak-through, and the opening or closing of the valve disc, when sound is generated by those actions. The movement of worn or abnormal internal parts can also be detected by this technique. Acoustic emission monitoring is limited in that the disc may be stuck or otherwise unable to produce any sound.

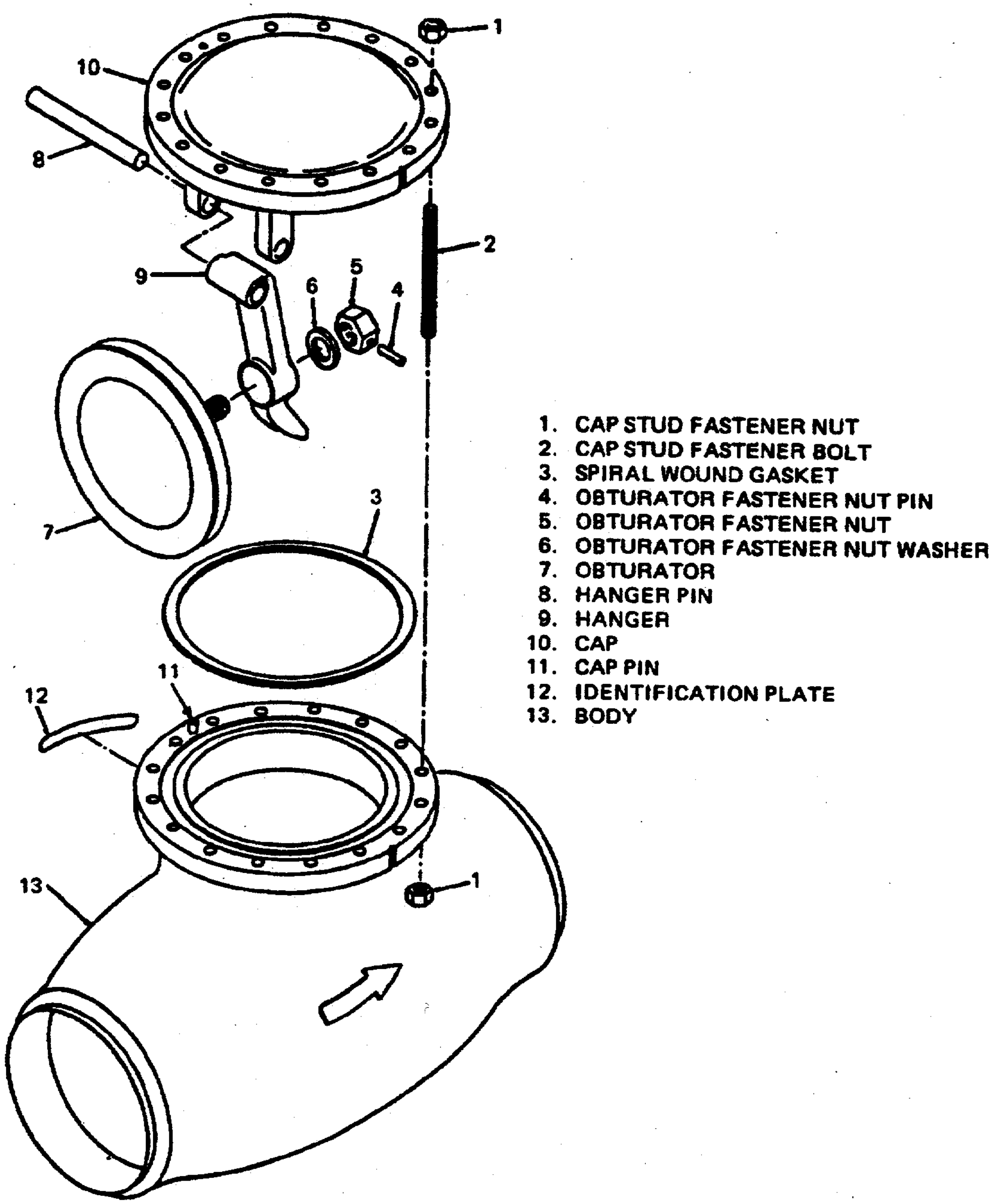

Figure 5.1. Typical Swing-Check Valve, Exploded View

Table 5.2. Summary of Detection Capability of Current SRs

Check Valve Component	Known Stressors Contributing to Age	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Method	Addressed by STS SRs?[(a)]
A. Body Assembly					
body, bonnet	vibration	fatigue	loss of strength, cracked welds	visual inspection for external leakage, analysis	no
	thermal-cycling	thermal stress	loss of strength, stress corrosion cracking, cracked welds	visual inspection for external leakage, analysis	no
	chemicals	chemical reactions, corrosion, pitting	wall-thinning, stress corrosion cracking	internal visual and volumetric examination	no
	flow	erosion, cavitation, pitting	wall-thinning, wear-reduction	visual inspection for external leakage, analysis for wall-thinning, volumetric and internal visual examination	no
	external environmental conditions (e.g., heat, humidity, and chemicals)	oxidation	loss of strength	analysis	no
		corrosion	wall-thinning	visual inspection for external leakage, analysis for thinning	no
	water hammer	fatigue	cracking	visual inspection for external leakage, volumetric examination	no
	pressure	fatigue	cracking	visual inspection for external leakage, volumetric examination	no
	steam cutting	erosion	wall-thinning	visual inspection for external leakage	no
external fasteners	vibration	fatigue, galling, and fretting	loosening, bending, seizure, fracture	visual inspection for external leakage, disassembly	no
	thermal-cycling	differential thermal expansion	loosening	visual inspection for external leakage	no

(a) Representative SRs are listed where applicable.

Table 5.2. (contd)

Check Valve Component	Known Stressors Contributing to Age	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Method	Addressed by STS SRs?[(a)]
external fasteners (contd)	external environmental conditions (e.g., heat, humidity, and chemicals)	stress corrosion, corrosion	cracking, fracture, stretching, loosening	disassembly, volumetric examination, visual inspection for external leakage	no
	water hammer	fatigue, impacts	stretching, loosening	visual inspection for external leakage. disassembly, volumetric examination	no
			B. Seals		
seals, gaskets, packing	thermal-cycling	swelling, shrinking	cracking, breakdown, loosening	visual inspection for external leakage	no
	heat	embrittlement, swelling	cracking, distortion	visual inspection for external leakage, disassembly	no
	pressure	fatigue, abrasion, erosion	breakdown, distortion, loosening	visual inspection for external leakage	no
	external environmental conditions (e.g., heat, humidity, and chemicals)	swelling,chemical reaction, oxidation, corrosion	cracking, distortion, hardening, breakdown, loss of integrity, loosening	visual inspection for external leakage, disassembly	no
	radiation	embrittlement	cracking, distortion	visual inspection for external leakage, disassembly	no
			C. Internals		
seat	operation (normal opening and closing)	abrasion, wear	distortion, internal leakage, restricted motion or flow; loose, broken, or detached parts	analysis for internal leakage, internal visual inspection	3.4.14.1'
	contaminants, debris	abrasion, wear, erosion	blockage, interference, stick open or shut, internal leakage	analysis for internal leakage, internal visual	no

(a) Representative SRs are listed where applicable.

Table 5.2. (contd)

Check Valve Component	Known Stressors Contributing to Age	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Method	Addressed by STS SRs?[(a)]
disc, hinge, hinge pins, bearings, bushings	operation	wear, galling	internal leakage; loose, broken or, detached parts, loosening, binding interferences	internal visual, analysis for internal leakage	no
	pressure	fatigue, galling, cavitation	bending, binding, distortion, cracking, fracture, sticking open or shut; loose, broken, or detached parts	analysis for internal leakage, internal visual	3.4.14.1, 3.6.3.6, 3.6.3.9
	chemicals	corrosion, chemical reactions, stress corrosion	thinning, cracking, interferences, leaking, binding, restricted motion or flow; loose broken, or detached parts	analysis for internal leakage, internal visual	no
	thermal-cycling	differential thermal expansion, thermal stress	loose, broken or detached parts, binding	analysis for internal leakage, internal visual	3.4.14.1
	flow	erosion, cavitation	thinning, loosening, interferences, cracking, leaking	analysis for internal leakage, internal visual	3.4.14.1
	vibration	fatigue, fretting, wear, galling	cracking, binding, lockup, increase in frictional resistance, interferences, sticking open or shut; loose, broken, or detached parts	analysis for internal leakage, internal visual	3.4.14.1

(a) Representative SRs are listed where applicable.

Ultrasonic examination focuses high-frequency sound waves into a part or subcomponent, measures the transmission time of the echo, and then determines the position of part, subcomponent, or flaw. Ultrasonic examination can be used to detect missing or stuck discs, loose hinge pin or disc connections, or worn hinge pins. Ultrasonic examination is limited by thick-walled valve bodies and those that contain low-density fluid as the sound waves become scattered. Ultrasonic examination may not show the entire travel path of the disc.

There are two methods of external magnet monitoring: the external alternating current (ac) magnet method and the external direct current (dc) magnet method.

- The external ac magnet method uses two coils of wire wrapped or attached to different CV locations. The transmitter coil is connected to a source of electric current at a fixed, selected frequency and thus produces a magnetic field. The receiver coil senses the magnetic field, which has been transmitted through the CV and warped by both the body and internals of the valve. The local magnetic field present at the receiver coil induces a current in that coil which can then be displayed and measured. Changes in the position of the CV internals produce variations in the receiver coil signal which may be monitored, quantified, and trended over time.

- The external dc magnet method makes use of one or more externally applied dc magnetic fields supplied either by permanent magnets or by coils carrying dc current. The dc magnetic fields are transmitted through the CV and detected externally at one or more locations by a magnetic field sensor, such as a gaussmeter that employs a Hall-effect probe. Changes in the magnetic field are then monitored and trended to determine the aging effects on the valve.

Magnetic flux signature analysis uses a permanently installed magnet and gaussmeter to detect the magnitude of the magnetic field. Magnetic flux signature analysis is the only intrusive method discussed in this section, since it requires the installation of a permanent magnet to the internal surface. Magnetic flux signature analysis can be used to monitor disc position and motion and worn internal parts. Limitations include the potential for the magnet to become demagnetized or attract metallic particles in the fluid, or the entire testing equipment can be affected by ambient magnetic fields.

Two other detection methods, radiography and pressure noise monitoring, were evaluated for use. These methods were considered inadequate for monitoring CV operations. Radiography was not considered because of the inability to acquire good radiography quality in field practice under adverse plant environmental conditions, particularly those of high temperature and background ionizing radiation that is typical of nuclear generating units. Pressure noise monitoring was also eliminated because the pressure noise spectra were complex signatures that were highly sensitive due to system and other unidentified effects, thus resulting in nonreproducable results.

5.4 Evaluation of Existing Surveillance Requirements for Effectiveness in Detecting Aging Degradation

The STS specify the overall inservice inspection and testing requirements for safety related systems and components. The inspection and testing of American Society of Mechanical Engineers (ASME) Class 1, 2, and 3 components are required to be in accordance with Section XI of the ASME Boiler and Pressure Vessel Code. Section XI requires CV testing that involves only two parameters: operation and seat leakage. These two testing requirements are reflected in the SRs. An example of an SR that requires CV operation (from a typical draft PWR STS, which is representative of those of the other major reactor designs) requires verification that at least one decay heat removal loop, including all associated CVs, is operating. An example of an SR that checks CV leakage requires verification of the leakage rate of the low-pressure injection system, including all associated CVs, at normal and emergency pressures.

Existing SRs focus on component operability concerns and not on condition monitoring to detect and trend age-related degradation. Sample SRs for valve leakage and valve operation are given in Appendix 5A.

5.5 Evaluation of Existing Surveillance Requirements for Possible Contributions to Premature Aging Degradation

As noted above, existing SRs related to CVs are designed to determine operability and are not designed to detect and trend aging degradation. These SRs do not contribute to aging (i.e., the SRs impose no additional aging influence on CVs beyond the greater influence of normal operation). The SRs that require operation are performed on such a low frequency as to render their aging effects negligible.

5.6 Recommendations to Improve or Supplement Surveillance Requirements

5.6.1 Recommendations from the NPAR Aging Assessments

The NPAR studies on CVs have made recommendations that will help detect CV age-related problems. The degradation detection methods described in Section 5.3 and Table 5.3 can provide information that is useful to determine the degree of age-related degradation and to ascertain the integrity of CV internal parts. These detection methods use different transducers and principles of operation, thus providing unique capabilities. While no one method can provide adequate or complete information as to CV integrity, acoustic emission monitoring combined with at least one other monitoring method can provide the means to determine required CV aging information.

Based on the referenced NPAR studies, the following actions are recommended to better address CV age-related degradation concerns:

1. Until the results of the degradation detection methods can be validated, the CVs should be visually examined once every other refueling cycle or whenever opened for any other reason. After that time, CVs should be visually examined whenever opened for any other reason. Check valves that are opened should be examined for evidence of the following:

- obturator guide wear, erosion, or corrosion
- obturator wear, erosion, or corrosion
- obturator hanger wear or fracture
- obturator fastener loosening, tightening, or breakage
- hanger pin wear, erosion, corrosion, or fracture
- hanger pin bearing wear, corrosion, or fracture
- hanger pin seal wear or degradation
- seat wear, erosion, or corrosion
- foreign material

- body wear, erosion, or corrosion
- fastener loosening, tightening, or breakage
- cap or bonnet seal degradation.

2. Check valves should be examined once every other refueling outage using acoustic emission monitoring combined with ultrasonic examination, external magnet monitoring, or magnetic flux signature analysis. Baseline data must be obtained and results must be validated by visual examination before total reliance on these methods is made. The diagnostic capabilities and limitations of the CV monitoring methods are summarized in Table 5.3.

All surveillance results must be trended over time to note aging effects on CVs and to identify potential age-related degradation.

5.6.2 Implementing Suggested Recommendations

Suggested SRs for CVs with associated surveillance frequencies to implement the recommendations from the NPAR assessments are listed in Table 5.4. These recommended SRs address the potential for undetected CV component degradation that was identified in Table 5.2, except for those effects with a very low probability of failure of the component, or those that are more appropriately addressed by an effective maintenance program.

An SR is not specified in Table 5.4 for each CV component; rather, the individual degradation detection methods that apply to a particular degradation effect on a component are grouped to form a generically stated SR. Each of these generic SRs would then be expanded by writing them for CVs throughout the STS in a form consistent with that of existing SRs, as identified in Appendix 5A.

Table 5.3. Diagnostic Capabilities and Limitations of CV Monitoring Methods

Method	Detects Internal Leakage	Detects Internal Impacts	Detects Fluttering	Intrusive	Sensitive to Ambient Conditions	Monitors Full Range of Disc Travel	Works with all Fluids
Acoustic emission monitoring	Yes	Yes	No	No	Yes, noise and vibration	No	Yes
Ultrasonic examination	No	Yes	Yes	No	Unknown	No	No
External magnet monitoring	No	Yes	Yes	No	Yes, nearby external magnetic fields	Yes	Yes
Magnetic flux signature analysis	No	Yes	Yes	Yes, requires installation of permanent magnet inside the valve	Yes, nearby external magnetic fields	Yes	Yes

Table 5.4. Surveillance Requirement Recommendations to Detect and Trend CV Aging Degradation

Surveillance Requirement	Frequency of Action
Visually examine CV subcomponents to verify that the design-basis operation of the CV will not be affected by the following: •wear •erosion •corrosion •fracture •foreign material •loosening •tightening	36 months or whenever opened. (This will be done until the degradation detection methods can be validated)
Trend CV parameters by means of acoustic emission monitoring combined with ultrasonic examination, external magnet monitoring, or magnetic flux signature analysis.	36 months

Appendix 5A

Summary of Check Valve Surveillance Requirements from Westinghouse STS

SR Number	Surveillance Requirement	Frequency	Detects Aging Degradation?
	Check Valve Cycling		
3.4.11.3	Perform a complete cycle of each solenoid air control valve and CV on the air accumulators in PORV control systems.	[18] months	no
	Check Valve Leakage		
3.4.14.1	Verify leakage from each reactor coolant system pressure islation valve is equivalent to $\leq$ 0.5 gpm per nominal inch of valve size up to a maximum of 5 gpm at a reactor coolant system pressure $\geq$ [2215] psig and $\leq$ [2255] psig.	In accordance with the Inservice Testing Program, and [18] months **AND** Before entering MODE 2 whenever the unit has been in MODE 5 for seven days or more, if leakage testing has not been performed in the previous nine months **AND** Within 24 hours following valve actuation due to automatic or manual action or flow through the valve	yes
	Check Valve Operation		
3.6.3.6	Cycle each weight or spring-loaded check valve **testable during operation** through one complete cycle of full travel, and verify each CV remains closed when the differential pressure in the direction of flow is $\leq$ [1.2] psid and opens when the differential pressure in the direction of flow is $\geq$ [1.2] psid and < [5.0] psid.	92 days	yes
3.6.3.9	Cycle each weight or spring-loaded check valve **not testable during operation** through one complete cycle of full travel, and verify each CV remains closed when the differential pressure in the direction of flow is $\leq$ [1.2] psid and opens when the differential pressure in the direction of flow is $\geq$ [1.2] psid and < [5.0] psid.	18 months	yes

6.0 Emergency Diesel Generator System

The Emergency Diesel Generator (EDG) system provides the backup electrical power needed by a nuclear power plant in the event of a loss of offsite ac power (LOOP). A reliable EDG system is essential because of serious consequences from failure to produce electrical power after a LOOP.

A Nuclear Plant Aging Research (NPAR) assessment of EDG systems was conducted by the Pacific Northwest Laboratory (Hoopingarner et al. 1987; Hoopingarner and Vause 1987; Hoopingarner and Zaloudek 1989). The study provided the technical basis for the EDG standard technical specifications (STS) evaluation. Additional information was obtained from Blahnik et al. (1992).

6.1 Emergency Diesel Generator System Description and Boundaries

A diagram of a diesel engine is presented as Figure 6.1; Figure 6.2 is a summary of the major subsystems of an EDG system:

- an instrument and control system, which includes the governor, control system, switch gear, protection system, and surveillance system. Components in these systems include circuit breakers, relays, contacts, buses, batteries, transformers, relays, sensors, wiring, terminations, alarms, recorders, monitors, dials, gauges, valves, linkages, and instrumentation

- a fuel oil system, which includes storage tanks, day tanks, transfer feed and booster pumps, nozzles, injectors, filters, heaters, valves, meters, strainers, and piping

- an intake and exhaust system, which includes air filters, turbochargers, silencers, and miscellaneous piping

- a generating system, which includes the generator (rotor, stator, and frame), exciter, voltage regulator, pedestal bearings, switches, wiring, and breakers

- an engine, which consists of the basic engine structure, including base assembly, crankcase, cylinder block, heads, main bearings, and liners; the drive train, consisting of the crankshaft, connecting rods and bearings, bushings, pistons, gears, camshaft, and flywheel; and the valve mechanisms, containing push rods, rocker arm assemblies, and intake and exhaust valves

- a starting system, which may include air motors, air-induction valving, piping, filters, strainers, controls, shut-off valves, relief valves, pressure-reducing valves, air compressors, air storage tanks, and air coolers and dryers

- a cooling system, which includes coolers or heat exchangers, expansion tanks, piping, valves, controls, heaters, auxiliary circulation pumps, and engine-driven pumpsa lubricating oil system, which includes motor-driven pumps, engine-driven pumps, sump pumps, oil coolers, oil heaters, filters, strainers, valves, and piping.

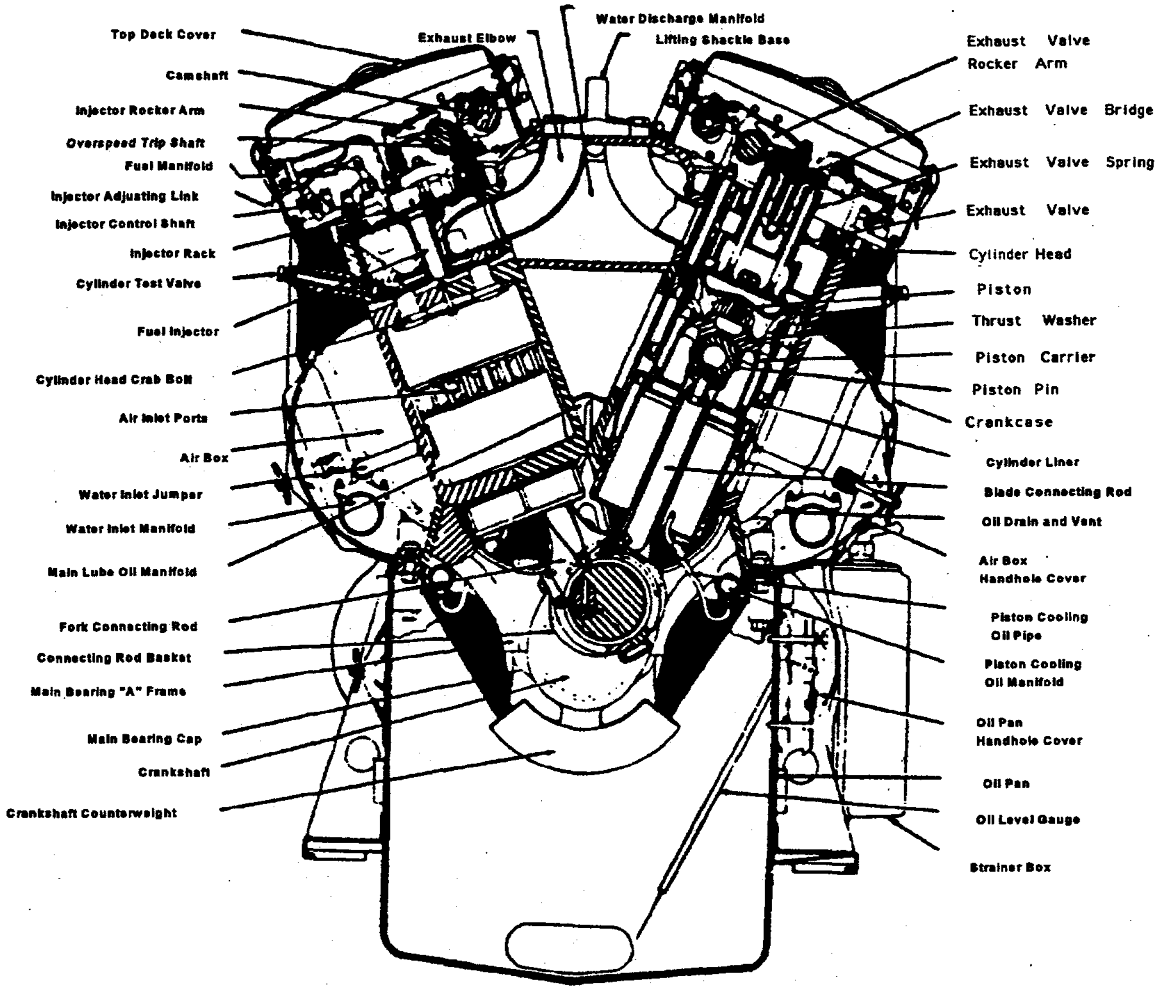

Figure 6.1. Cross Section of the GM-EMD 645E Series Engine

6.2 Stressors, Aging Mechanisms, and Aging Effects

Known EDG system stressors, the resulting aging mechanisms and aging degradation effects, and the locations where the stressors and aging mechanisms operate are summarized in Table 6.1 for the major EDG subsystems and components. The most important of these stressors and mechanisms for the EDG system include corrosion, vibration-induced fatigue and fastener loosening, oxidation, thermal stresses, shock, contamination, adverse environmental conditions, biofouling, manufacturing or design errors, and improper or excessive operation. Inadequate or improper maintenance also can contribute to premature degradation of the EDG system.

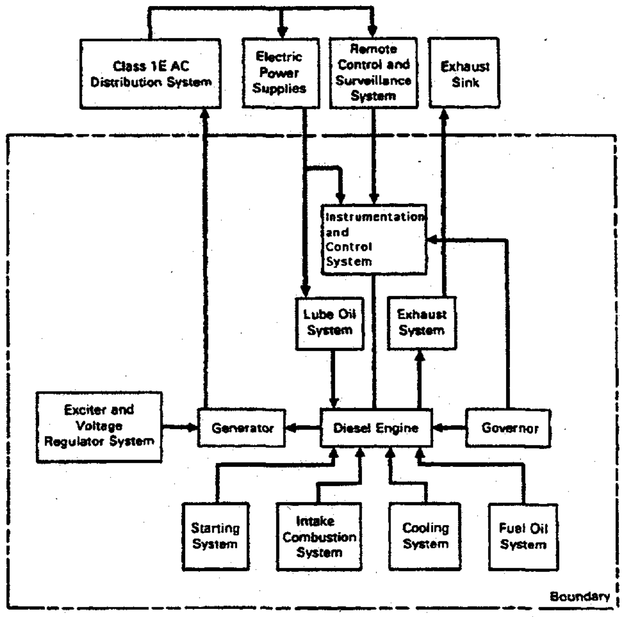

Figure 6.2. Diesel System Boundaries

Also noted in Table 6.1 is whether a particular aging degradation effect is detected by the current surveillance requirements (SRs). A representative SR is cited for aging effects that are detectable; more than one SR may be applicable. A potential deficiency is identified when a particular aging effect is not detected by any SRs (i.e., the component may experience undetected degradation). Recommended SRs to address the undetected degradation are listed in Section 6.6. Degradation that is more appropriately addressed by an effective maintenance program (e.g., vibration-induced loosening) is not included.

The EDG subsystems and components and their stressors, aging mechanisms, and resultant aging effects are listed below.

1. The instrument and control system is subject to

- corrosion
- deterioration of seals, gaskets, and other organic components
- oxidation
- failures of thermocouples and other sensors and instruments
- connections and linkages loosening
- dirty and corroded contacts
- pneumatic or hydraulic components fouling
- vibration-induced fatigue of components
- short circuiting of electrical circuits
- leakages.

Table 6.1. Summary of Detection Capability of Current SRs

EDG Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Method	Addressed by STS SRs?[a]
Instrument and Control System					
governor	contaminants	fouling	blocking, drift	operation	3.8.1.2, 3.8.1.9, 3.8.1.10, 3.8.1.11, 3.8.1.12, 3.8.1.19
				visual	no
	operation, vibration	fatigue	binding/lockup, drift, sticking open/shut	operation	3.8.1.2, 3.8.1.9, 3.8.1.10, 3.8.1.11, 3.8.1.12, 3.8.1.19
				visual	no
seals, gaskets, other organic compounds	heat	chemical reactions, embrittlement	hardening, loss of integrity, softening, cracking	visual	no
thermocouples	humidity	oxidation, corrosion	drift, open circuit	calibration	no
	thermal-cycling	embrittlement, fatigue	drift, open circuit	calibration	no
connectors and linkages	vibration	wear	binding/lockup, drift, loosening, loss of mechanical strength, sticking open/shut	operation	3.8.1.2, 3.8.1.9, 3.8.1.10, 3.8.1.11, 3.8.1.12, 3.8.1.19, 3.8.1.11
				visual	no
	operation	fatigue	binding/lockup, drift, loosening, sticking open/shut	operation	3.8.1.2, 3.8.1.9, 3.8.1.10, 3.8.1.11, 3.8.1.12, 3.8.1.19
pneumatic components	operation, vibration	fatigue	wear, leakage	operation	3.8.3.2
				visual	no
	contaminants	fouling	blockage	operation	3.8.1.2
				visual	no

(a) Representative SRs are listed where applicable.

Table 6.1. (contd)

EDG Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Method	Addressed by STS SRs?[(a)]
hydraulic components	operation, vibration	wear, vibration, loosening	loss of function, leakage	operation	3.8.1.2
	contaminants	fouling	increase in frictional resistance	operation	3.8.1.2
				visual	no
circuit breakers	operation	wear, galling	increase in electrical resistance, increases in response time	operation	3.8.1.8, 3.8.1.11, 3.8.1.19
				visual	no
	contaminants	pitting, arcing, corrosion	melting, seizure, sticking shut	operation	3.8.1.8, 3.8.1.11, 3.8.1.19
				visual	no
	humidity	arcing, galling, pitting, oxidation	sticking open/shut, drift	operation	3.8.1.8, 3.8.1.11, 3.8.1.19
				visual	no
relays	ohmic heating	overheating	breakdown of insulation, decrease in electrical resistance	operation	3.8.1.2, 3.8.1.8, 3.8.1.11
				visual	no
	operation, dust	wear, pitting, contamination	drift, sticking open/shut	operation	3.8.1.2, 3.8.1.8
				visual	no
	overvoltage operation	overheating, arcing	sticking open/shut, increase in response time, decrease in electrical resistance, melting	operation	3.8.1.19
				visual	no
	operation	wear	wear-reduction	operation	3.8.1.2
				internal visual	no
	contaminants	arcing, fouling	blockage, binding/lockup, sticking open/shut	operation	3.8.1.2
				internal visual	no

(a) Representative SRs are listed where applicable.

Table 6.1. (contd)

EDG Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Method	Addressed by STS SRs?[a]
relays (contd)	ohmic heating	overheating, oxidation	shorting, melting	resistance bridge test	no
				operation	3.8.1.2
	external environmental conditions (e.g., temperature, humidity, chemicals)	oxidation, corrosion, galling, pitting, arcing	decrease or increase in electrical resistance, shorting, open circuit	resistance bridge test	no
				operation	3.8.1.2
contacts	ohmic heating	overheating	sticking open/shut, melting	operation	3.8.1.2
				visual	no
	operation	wear, pitting, galling	sticking open/shut	operation	3.8.1.2
				visual	no
	overvoltage operation	overheating, arcing	sticking open/shut, increase in response time, resistance, melting	operation	3.8.1.2
				visual	no
	external environmental conditions (e.g., temperature, humidity, chemicals)	oxidation	increases in electrical resistance, contamination	operational	3.8.1.2
				visual	no
		corrosion	increase in electrical resistance, interferences, increase in frictional resistance, contamination	operational	3.8.1.2
				visual	no
sensors	humidity	oxidation, chemical reactions, corrosion	decrease in electrical resistance, drift, increase in electrical resistance	operation	3.8.1.2, 3.8.1.13
				resistance bridge test	no
	heat	overheating, differential thermal expansion	increase in electrical resistance or decrease in electrical resistance, breakdown of insulation	operation	3.8.1.2, 3.8.1.13
				resistance bridge test	no

(a) Representative SRs are listed where applicable.

Table 6.1. (contd)

EDG Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Method	Addressed by STS SRs?[(a)]
sensors (contd)	operation	wear, fatigue	seizure, breakdown, increase in electrical resistance	operation	3.8.1.2, 3.8.1.13
				resistance bridge test	no
wire	overvoltage operation	overheating	melting, open circuit	operation	3.8.1.2
				resistance bridge test	no
insulation on wire	external environmental conditions, (e.g., temperature, humidity, chemicals)	chemical reactions, embrittlement	loss of dielectric strength, fracture, cracking, breakdown	visual, polarization index testing, resistance bridge test	no
	overvoltage operation	embrittlement	loss of dielectric strength, fracture, breakdown	visual, polarization index testing, resistance bridge test	no
	mechanical overload	cracking	loss of dielectric strength, fracture, breakdown	visual, polarization index testing, resistance bridge test	no
terminations	thermal-cycling (ambient air heating and cooling)	oxidation, fatigue	open circuit, increase in electrical resistance, arcing	visual, resistance bridge testing	no
	humidity	oxidation, chemical reaction	increase in electrical resistance, corrosion, open circuit	visual, resistance bridge testing	no
	vibration	fatigue, wear, loosening	open circuit, shorting	visual, resistance bridge testing	no
Fuel Oil System					
tanks	operation	oxidation, chemical reactions	loss of integrity	visual, pressure test	no
	vibration (day tank)	wear	loss of integrity	visual, pressure test	no

(a) Representative SRs are listed where applicable.

Table 6.1. (contd)

EDG Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Method	Addressed by STS SRs?[(a)]
fuel pump	operation	wear (inadequate lubrication)	decrease of pumping head, breakdown	pressure test	no
				operation	3.8.1.2, 3.8.1.6
	contaminants	fouling, wear	seizure or breakdown	visual	no
				operation	3.8.1.2, 3.8.1.6
injectors	contaminants	fouling	blockage	visual	no
valves	contaminants	clogging (fouling)	blockage	visual	no
				operation	3.8.1.2, 3.8.1.6
			sticking open/shut	leak test	no
fuel oil	contaminants (water, biofouling)	chemical reactions	increase in oil viscosity, blockage	chemical analysis	3.8.3.3
fuel lines at fittings	vibration	fatigue, vibration loosening	loss of integrity (leaking)	pressure test	no
				operation	3.8.1.2
valves and piping	humidity (moisture accumulation)	corrosion	wall-thinning, loss of integrity	pressure test	no
				operation	3.8.1.2
strainers	contaminants (corrosion products)	clogging (fouling)	blockage	differential pressure test	no
				operation	3.8.1.2
filters	contaminants (corrosion products)	clogging (fouling)	blockage	differential pressure test	no
				operation	3.8.1.2
air tanks	humidity (condensate)	corrosion	wall-thinning, loss of integrity	pressure test	3.8.3.4
air motors	contaminants	wear, abrasion	breakdown, wall-thinning	operation	3.8.1.2
Intake and Exhaust System					
turbocharger parts including bearings	operation and contaminants	heat, corrosion	seizure, blockage,	operation	3.8.1.2
				visual	no
filters	contaminants	clogging	blockage	differential pressure test	no
exhaust system piping and components	contaminants	carbon fouling	blockage	operation	3.8.1.2
	vibration	wear fatigue	blockage, leakage	visual	no

(a) Representative SRs are listed where applicable.

Table 6.1. (contd)

EDG Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Method	Addressed by STS SRs?[a]
fittings, couplings	vibration	wear, fatigue	loosening, loss of integrity, leakage	operation	3.8.1.2
				pressure test	no
Generating System					
insulation	external environmental conditions (e.g., temperature, humidity, chemicals)	oxidation, chemical reactions	breakdown, shorting, melting, decrease in electrical resistance, decrease in heat resistance	visual, polarization index testing, resistance bridge test	no
contacts	operation	oxidation, pitting	increase in electrical resistance, sticking open/shut	visual	no
				operation	3.8.1.2
	overvoltage operation	arcing, oxidation, pitting	shorting, melting, sticking open/shut	visual	no
				operation	3.8.1.2
	contaminants	fouling	increase in electrical resistance, shorting	visual	no
				operation	3.8.1.2
	external environmental conditions (e.g., temperature, humidity, chemicals)	corrosion, oxidation	increase in electrical resistance, contamination	visual	no
				operation	3.8.1.2
brushes and bearings	contaminants	abrasion	breakdown, increase in electrical resistance, shorting	visual	no
				operation	3.8.1.2
coils	heat	oxidation	increase in electrical resistance, shorting	resistance bridge test	no
	overvoltage operation	arcing, overheating	melting, shorting	resistance bridge test	no
rotating parts	overspeed	high stress, failure	damage, loss of integrity	visual	no
				operation	3.8.1.2

(a) Representative SRs are listed where applicable.

Table 6.1. (contd)

EDG Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Method	Addressed by STS SRs?[(a)]
exciters and voltage regulators	vibration	wear, fatigue	open circuit, binding/lockup, shorting	operation	3.8.1.2
				resistance bridge test	no
diodes and other electrical components	thermal-cycling and ohmic effects	overheating, oxidation, arcing	open circuit, melting, increase in electrical resistance	operation	3.8.1.2
				resistance bridge test	no
Diesel Engine					
cylinder block and head	contaminants (corrosion products)	corrosion, wear	breakdown, seizure	high-temperature conditions	no
	fast engine loading	thermal stress, excessive wear	breakdown, head cracking	cylinder compression test	no
				operation, loaded	3.8.1.2
main bearings	contaminants in oil	metal-contact wear	seizure, breakdown	visual	no
				operation	3.8.1.2
	fast loading	metal-contact wear	wear, seizure, breakdown	visual	no
				operation	3.8.1.2
liners	water chemistry	corrosion	leakage, wall-thinning	operation	3.8.1.2
	fast loading	engine loads and no lubrication	excessive wear, scuffing, crankcase explosions	cylinder temp. balance, compression test	no
	inadequate lubrication	wear	scuffing, breakdown, crankcase explosions	cylinder temp. balance, compression test	no
crankshaft	inadequate lubrication	wear, scoring	excessive wear and bearing clearance	visual	no
				operation	3.8.1.2
	fast loading	wear, scoring	excessive wear and bearing clearance	visual	no
				operation	3.8.1.2
connecting rods	fast loading (mechanical stresses)	fatigue	breakdown	visual	no
				operation	3.8.1.2

(a) Representative SRs are listed where applicable.

Table 6.1. (contd)

EDG Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Method	Addressed by STS SRs?[a]
bushings, connecting rod bearings	contaminants	wear, scoring	excessive wear, early failure	visual	no
				operation	3.8.1.2
	inadequate lubrication	wear, scoring	excessive wear, early failure	visual	no
				operation	3.8.1.2
pistons	contaminants	wear	excessive wear, early failure	cylinder temp. balance, compression test	no
	inadequate lubrication	wear	scuffing, early failure	cylinder temp. balance, compression test	no
	fast loading	wear	scuffing, early failure	cylinder temp. balance, compression test	no
gears	impacts, torsional vibration	wear, fatigue	fracture, excessive wear	operation	3.8.1.2
				visual	no
camshaft	inadequate lubrication	wear, scoring	excessive wear	visual	no
	contaminants	wear, scoring	excessive wear	visual	no
	fast loading	wear, scoring	excessive wear	visual	no
intake and exhaust valves	contaminants	overheating, fouling, thermal stress	distortion, fracture, sticking open/shut	visual	no
				cylinder compression test	no
	thermal-cycling	stress, wear	distortion, cracking	visual	no
				cylinder compression test	no
valve push rods	operation	stress, fatigue, bending	loss of function	visual	no
rocker-arm assemblies	inadequate lubrication	wear	loosening, distortion	visual or physical measurement	no
	contaminants	wear	loosening, distortion	visual or physical measurement	no
air valves	contaminants (dirt and corrosion products)	wear	leakage	pressure test	no
		plugging	sticking open/shut	operation	3.8.1.2, 3.8.3.4

(a) Representative SRs are listed where applicable.

Table 6.1. (contd)

EDG Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Method	Addressed by STS SRs?[(a)]
air coolers and dryers	contaminants (dirt and corrosion products)	fouling	contamination, blockage	visual	no
				operation	3.8.1.2, 3.8.3.4
heat exchangers	chemicals	corrosion (bulk and pitting)	wall-thinning, loss of integrity	leakage	no
	contaminants	fouling	blockage	differential pressure test or flow test	no
coolers	chemicals	corrosion (bulk and pitting)	wall-thinning, loss of integrity	leakage	no
	contaminants	fouling	blockage	differential pressure test or flow test	no
radiators	contaminants	fouling	blockage	differential pressure test	no
seals, O-rings, gaskets, and hoses	heat, thermal radiant effects	oxidation, chemical reactions	hardening, cracking, loss of integrity	pressure tests	no
	operation	curing, chemical reactions	hardening, cracking, loss of integrity	pressure tests	no
pump impellers and bearings	operation	vibration, wear	seizure, breakdown	operation	3.8.1.2
piping	operation, vibration	fatigue, vibration loosening	loss of integrity (leaks)	pressure test	no
water	contaminants	microbiological fouling	contamination, blockage, breakdown	chemical analyses, although better is an annual flush of system	no
heat-exchanger tubes	contaminants	corrosion (pitting, bulk)	loss of integrity	pressure test	no
oil-pump drive gears	operation	wear	loss of mechanical strength, breakdown	pressure test on oil pump	no
lubricating oil heaters	operation and contaminants	fouling (carbon buildup)	blockage causing loss of cooling capacity	oil temperature	no
lubricating oil	contaminants (including water)	abrasion, wear, chemical reactions	breakdown of oil, seizure of pistons in DG	periodic oil changes	no

(a) Representative SRs are listed where applicable.

2. Fuel oil system damage or failure can result from

- buildup of varnish within the diesel engine from deteriorated fuel oil
- chemical effects of the diesel fuel on various organic compounds in the system and elsewhere within the diesel generator system
- corrosion of the engine and other damage from water in the fuel
- sticking of engine components
- clogging of fuel lines from dirt, water, or sludge
- fouling of filters
- vibration-induced leaks in fuel lines at fittings
- clogged valves due to particles in the fuel
- sticking of the fuel pump and other linkages and bearings due to inadequate lubrication or dust accumulation
- growth of biological contaminants in the fuel.

3. The intake and exhaust system can fail by

- corrosion of bearings and other turbocharger parts
- plugging of filters by dirt and water
- carbon fouling and temperature buildup in exhaust system components
- vibration damage of piping, fittings, couplings, and supports
- abrasion and wear due to inadequate lubrication
- leakage of corrosive gases into other systems
- thermal stresses because of design inadequacies or loss of lubrication or cooling.

4. The generating system is subject to

- deterioration of insulation within the generator
- burnout and oxidation of contacts
- breakdown of insulation

- contamination of lubricants
- abrasion of brushes
- plugging of cooling passageways, resulting in damage from overheating
- electrical phase balance problems from damaged coils
- overspeed damage to rotating parts
- vibration damage to exciters and voltage regulators
- burnout of coils and control panels
- grit and moisture fouling of contacts
- damage to diodes and other components from thermal effects
- voltage spikes and stray current damage to various components
- overheating from inadequate ventilation.

5. Diesel engine age-related failures result from

- corrosion and inadequate lubrication
- effects of water chemistry
- wear and corrosion of cylinder liners
- plugging of oil holes resulting in inadequate lubrication and overheating
- dirt and other contaminants in the oil
- improper lubricants
- fretting and wear of high-speed rotating components
- over-stressing of basic structural components
- thermal distortion and valve-seat cracking
- cavitation and metal-contact wear in bearings
- erosion of mating surfaces from dirt in the oil or improper torquing of bolts
- excessive wear during fast engine loading

- vibration
- wear, fatigue, and mechanical deflection in rotating parts
- fretting due to loosening of fasteners
- torsional vibration and backlash wear of gears
- improper lubrication of cam and bearing surfaces
- oil leaks
- deterioration of seals and gaskets
- blowby of exhaust gases leading to lubricant contamination
- cracking due to high-thermal stresses.

6. Starting system failures result from

- corrosion due to internal moisture accumulation
- corroding and plugging of strainers and filters
- corrosion in the air tank from condensate formation
- wear and abrasion in air motors and valves
- fouling of valves due to air-system contamination from corrosion products or dirt
- plugging of strainers and filters from corrosion products or moisture.

7. Cooling system failures result from

- pitting corrosion and bulk corrosion of heat exchangers and other coolers
- oxidation, ozone effects, and heat deterioration of seals and other organics
- cavitation and wear of impellers and bearings
- pinhole leaks in piping
- plugging of coolers, heat exchangers, and radiators
- deterioration and leakage of gaskets
- deterioration of O-rings and other seals from thermal and thermal-radiant effects

- biofouling from organisms or contaminants in the inlet water.

8. Lubricating oil system failures are associated with

- pitting and bulk corrosion of heat exchanger tubes
- vibration-induced damage, wear, and other deterioration of pump drive gears
- fatigue of springs and other vibrating components
- carbon build-up in the lubricating oil heater, causing plugging
- potential effects of water or other chemical impurities in the oil.

6.3 Degradation Detection Methods

Several methods that are effective in detecting aging degradation in the EDG system have been developed, either historically or in response to specific aging concerns. The specific detection methods applicable to EDG system degradation are identified in Table 6.1. Methods that are useful and appropriate for inclusion in the SRs are identified in Section 6.6 as recommendations to improve or supplement the SRs.

6.4 Evaluation of Existing Surveillance Requirements for Effectiveness in Detecting Aging Degradation

The SRs for EDG systems for the Westinghouse plant STS are summarized in Appendix 6A. The existing SRs focus primarily on operability concerns and not on detection and trending of aging degradation. The engine and its systems are tested during any of the following SRs: 3.8.1.2, 3.8.1.3, 3.8.1.7, 3.8.1.9, 3.8.1.10, 3.8.1.11, 3.8.1.12, 3.8.1.14, 3.8.1.15, 3.8.1.16, 3.8.1.17, 3.8.1.19, and 3.8.1.20.

1. The Instrument and Control System

The SRs relevant to the EDG instrument and control system include 3.8.1.2, 3.8.1.8, 3.8.1.9, 3.8.1.10, 3.8.1.11, 3.1.8.12, 3.1.8.13, and 3.8.1.19. These SRs are either EDG starts and runs or switching tests that, from the instrument and control standpoint, would indicate only when the failure of a component or subsystem has occurred and would not necessarily predict aging degradation.

2. The Fuel Oil System

The SRs relevant to the fuel oil system require operability testing of the EDG and the fuel oil transfer system (3.8.1.2, 3.8.1.6) and analysis of the new and stored fuel oil for contaminants (3.8.3.3).

3. The Intake and Exhaust System

The chief STS SR for the intake and exhaust system is the overall operability test of SR 3.8.1.2. If this system is inoperable, the EDG will be inoperable. Exhaust system temperature and turbocharger performance are monitored by typical engine system instrumentation.

4. The Generating System

The chief STS SR for the generating system is the overall operability test of SR 3.8.1.2. Instrumentation will stop system operation if phase balance exceeds the established limits.

5. The Diesel Engine

There are many STS SRs for the diesel engine. The overall operability tests are SRs 3.8.1.2 and 3.8.1.3. These tests provide information concerning the operability of the diesel engine and, to that extent, provide a means of detecting the aging process for the diesel, especially if the typically available engine instrumentation is used to detect and monitor engine performance.

6. The Starting System

The SRs relevant to the EDG starting system are 3.8.1.2 and 3.8.3.4. These are EDG starts and runs or air-start receiver pressure tests that, for the starting system, would indicate only when the failure of a component or subsystem has occurred and would not necessarily predict aging degradation.

7. The Cooling System

The only STS SR for the cooling system is the overall operability test of SR 3.8.1.2. If this system is inoperable, the EDG will be inoperable. However, every manufacturer includes high water-temperature alarm and shutdown instrumentation as part of the EDG installation. In addition, daily walkdown and surveillance checks of the standby cooling system are part of plant procedures.

8. The Lubricating Oil System

There are no specific SRs for the EDGs lubricating oil system other than a verification of the lubricating oil inventory (3.8.3.2). However, chemical and particulate analysis of the lubricant would provide a method for predicting the failure of bearings, rings, and other diesel components. In addition, the EDG start and run SRs (3.8.1.2, 3.8.1.7, 3.8.1.11, 3.8.1.12, 3.8.1.15, 3.8.1.19, and 3.8.1.20) have incorporated the allowance that "All DG starts may be preceded by an engine prelube period." This was a specific recommendation of the NPAR studies and will result in a significant reduction in aging damage to EDGs during surveillance testing.

Manufacturer requirements for maintenance and reliability are the bases used by utilities to disassemble and evaluate the serviceability of such engine components as rings, bearings, and pistons. The most appropriate time to conduct measurements and certain evaluations to detect the aging degradation of these components is when they are disassembled. However, the NPAR study found an adverse reliability impact if these component disassembles were performed too often.

6.5 Evaluation of Existing Surveillance Requirements for Possible Contributions to Premature Aging Degradation

The existing SRs for the EDG system focus primarily on operability concerns and not on detection and trending of aging degradation. Because of this operability focus, some of the more frequently performed tests have the potential to contribute to the premature aging degradation of EDG subsystems and components.

1. The Instrument and Control System

The SRs that are intended to check the instrument and control system are considered to have more potential to contribute to the premature aging degradation of the overall EDG system than to adversely affect the control system. Conversely, engine vibration, heat, and other operating conditions from all of the surveillances affect and contribute to aging of the instrumentation and control system. From an aging viewpoint, permitting certain SRs that are intended to check instrument and control system operation to be performed electronically without an engine start would reduce aging influences. Examples of these SRs are 3.8.1.11, 3.8.1.13, 3.8.1.17, 3.8.1.18, and 3.8.1.19.

Therefore, these instrument and control system SRs were judged to contribute to premature aging in accordance with the findings of PNL-7516, *Emergency Diesel Generator Technical Specifications Study Results* (Hoopingarner 1991). A "correct signal" check without an engine start seemed to be a more defensible regulatory position. The recommendations of Hoopingarner (1991) have been partially incorporated in the STS.

2. The Fuel Oil System

The SRs specifically related to the fuel oil transfer system and to the analysis of the new and stored fuel oil for contaminants did not contribute to premature aging degradation.

3. The Intake and Exhaust System

The start and run SRs in STS Section 3.8.1 were evaluated and judged to contribute to premature aging degradation. Surveillance requirements associated with fast engine loading especially had negative aging influences on turbocharger bearings and life and on certain other components.

4. The Generating System

The start and run SRs in STS Section 3.8.1 were evaluated and judged to contribute to premature aging degradation. SRs associated especially with generator overspeed, fast starting sequences, and load rejection tests had negative aging influences.

5. The Diesel Engine

The start and run SRs in STS Section 3.8.1 were evaluated and judged to contribute to some extent to premature engine aging degradation. Those associated especially with engine overspeed, fast engine loading sequences, and engine overload testing had negative aging influences. The other SRs promote aging only in the general use sense and as outlined in the instrument and control system discussion.

6. The Starting System

The air-start receiver pressure tests have no aging effect on EDG hardware. The EDG start tests contribute to premature aging degradation only in the general use sense and as outlined in the instrument and control system discussion.

7. The Cooling System

No SRs exist that are intended for surveillance of this system. Plant-specific daily surveillances of cooling system temperature and condition are performed and are considered as part of the overall surveillance of the EDG system, but these do not contribute to premature aging degradation. Surveillance requirements that involve full engine loads for longer periods of time check the aged condition of this system without adding to specific cooling system aging concerns.

8. The Lubricating Oil System

Surveillance requirement 3.8.3.2 related to the lubricating oil system was neutral for aging concerns and somewhat immaterial. The amount of lubricating oil inventory is misleading for a surveillance concern. A more appropriate safety and regulatory concern is if the engine oil system contains the proper amount of oil.

6.6 Recommendations to Improve or Supplement Surveillance Requirements

6.6.1 Recommendations from the NPAR Aging Assessments

The NPAR studies of the EDG system have developed additional recommendations that address age-related issues. Not every degradation detection method identified in Table 6.1 is appropriate for inclusion in SRs (e.g., individual cylinder exhaust temperature monitoring can be very effective in detecting age-related degradation, but it is a method that is better suited for inclusion in a maintenance program than in the STS).

The following recommendations address aging issues in the SRs, making them more effective in detecting, trending, and monitoring EDG system degradation before failure. These recommendations are presented for incorporation into SRs for the risk-significant EDG system and its components.

1. The Instrumentation and Control System

The recommendations of Section 2.3 of Hoopingarner (1991) are suggested for incorporation in the SRs. These recommendations are, in condensed form, a reduction in the number of unnecessary and redundant engine starts.

2. The Fuel Oil System

Current SRs require that a seven-day fuel oil supply be available at all times for emergencies. As identified in the NPAR study, this large fuel oil inventory is subject to several aging mechanisms. The current required inventory of fuel does not always permit effective fuel aging management. Reliability would be improved if the licensees were permitted to use a larger amount of the fuel during stable weather and electrical grid conditions and if they were encouraged to run the engines for longer periods of time to facilitate trending and assessing EDG conditions.

3. The Intake and Exhaust System

There are no additional recommended SRs for this system.

4. The Generating System

The SRs that are imposed on the engine affect the generator system in the same way for aging influences. Fast loading rates, overspeed risks, and unnecessary operation lead to accelerated aging in the generator, as well as in the engine.

5. The Diesel Engine

As with the instrumentation and control system, the recommendations of Section 2.3 of Hoopingarner (1991) are suggested for incorporation in the SRs. The NPAR recommendation to "Significantly reduce the number of engine starts on a monthly or yearly basis" could be met partially by the logic and sophistication of the scheduling of the required surveillances. However, the intent of the NPAR recommendation was to address false starts and other excessive mandatory engine starts that have the potential to contribute to the premature aging degradation of EDG subsystems and components.

6. The Starting System

All SRs related to the EDG starting system are neutral for aging and, therefore, impose no aging influence on the hardware.

7. The Cooling System

There are no additional recommended SRs for this system.

8. The Lubricating Oil System

All SRs related to the lubricating oil system are either helpful or have no aging concerns.

6.6.2 Implementing Suggested Recommendations

The recommendations from the NPAR aging assessment of EDG systems are given in Table 6.2, in order of importance. The degree of implementation into the STS is indicated by the terms "complete," "partial," and "none." "Complete" implies that the full intent of the recommendation was incorporated. "Partial" implies that the recommendation was partly incorporated, but that there were surveillances in which NPAR improvements might have been used but were not. "None" indicates the NPAR study had no impact on the surveillances.

Table 6.2. Overview of the Status of Incorporation of NPAR EDG Recommendations into the STS

NPAR Recommendations	How Addressed in STS	Future Action Recommended	Specifics
1 - Eliminate, where possible, short engine run times and excessive idle time.	Complete	None	
2 - Reduce the load application rates for testing purposes and gradually add load over a 15-minute period.	Partial	PNL-7516, page 2.11	Testing requirements have been relaxed, but engineered safety feaure signals still require fast loading; relax engineered safety feature load application rates.
3 - Make necessary changes to support the reliability emphasis of Regulatory Guide 1.9, Revision 3, and delete the statistical emphasis.	Partial	PNL-7516, page 2.13	Statistical requirements may be relaxed; PNL-7516 addresses most of the aging concerns.
4 - Increase the maximum EDG start time to the 25-to-30-seconds range for all engine operation demands.	Partial	PNL-7516, page 2.12	Slow test times are allowed, but plant signals still require fast (10 second) starts; relax plant signal fast-start requirements.
5 - Significantly reduce the number of engine starts monthly or yearly.	Partial	PNL-7516, page 2.10	The number of starts have been reduced, but further reduction would additionally reduce engine stressors (e.g., fewer automatic starts as now required by STS).
6 - Many unnecessary and partially redundant tests and engine starts in the 18-month period could be eliminated, as well as unnecessary engine starts due to false engineered safety feature signals.	Partial	PNL-7516, page 2.14	See specifics for "5"
7 - Address fuel oil storage to permit flexibility and a larger fraction of stored fuel use before replacement with new fuel.	None	PNL-7516, page 2.13	Allow use of a larger percent of onsite stored fuel.
8 - Reduce the EDG testing loads to 90% of the continuous load rating, or to the plant emergency unit load, whichever is less.	None	PNL-7516, page 2.11	Reduce to 90% to 95% or actual plant load, whichever is smaller.

Appendix 6A

Summary of Emergency Diesel Generator System Surveillance Requirements from Westinghouse STS

SR Number	Surveillance Requirement	Frequency	Detects Aging Degradation?
	Loss-of-Power Diesel Generator Start Instrumentation		
3.3.5.1	Perform channel check.	12 hour	no
3.3.5.2	Perform tripping actuation device operational test.	31 days	no
3.3.5.3	Verify system actuation response time is within limit.	18 months on a staggered test basis	no
3.3.5.4	Perform channel calibration with [setpoint Allowable Value] [Trip Setpoint and Allowable Value] as follows: a. Loss of voltage Allowable Value ≥ [2912] V with a time delay of [0.8] ± [ ] second. Loss of voltage Trip Setpoint ≥ [2975] V with a time delay of [0.8] ± [ ] second. b. Degraded voltage Allowable Value ≥ [3683] V with a time delay of [20] ± [ ] seconds. Degraded voltage Trip Setpoint ≥ [3746] V with a time delay of [20] ± [ ] seconds.	18 months	no
	Surveillances for Alternating Current Sources - Operating		
3.8.1.2	Verify each diesel generator starts from standby conditions and achieves steady state voltage ≥ [3740] V and ≤ [4580] V, and frequency ≥ [58.8] Hz and ≤ [61.2] Hz.	31 days for ≤ three failures in the last 25 valid tests. Seven days (but not less than 24 hours) for ≥ four failures in the last 25 valid tests.	yes
3.8.1.3	Verify each diesel generator is synchronized and loaded and operates for ≥ 60 minutes at a load ≥ [4500] kW and ≤ [5000] kW.	31 days for ≤ three failures in the last 25 valid tests. Seven days (but not less than 24 hours) for ≥ four failures in the last 25 valid tests	no
3.8.1.4	Verify each day tank [and engine mounted tank] contains ≥ [220] gal of fuel oil.	31 days	no
3.8.1.5	Check for and remove accumulated water from each day tank [and engine-mounted tank].	[31] days	no

SR Number	Surveillance Requirement	Frequency	Detects Aging Degradation?
3.8.1.6	Verify the fuel oil transfer system operates to [automatically] transfer fuel oil from storage tank[s] to the day tank [and engine-mounted tank].	[92] days	yes
3.8.1.7	Verify each diesel generator starts from standby condition and achieves in ≤ [10] seconds, voltage ≥ [3740] V and ≤ [4580] V, and frequency ≥ [58.8] Hz and ≤ [61.2] Hz.	184 days	no
3.8.1.8	Verify [automatic [and] manual] transfer of alternating current power sources from the normal offsite circuit to each alternate [required] offsite circuit.	[18 months]	no
3.8.1.9	Verify each diesel generator operating at a power factor ≤ [0.9] rejects a load ≥ [1200] kW, and: a. following load rejection, the frequency is ≤ [63] Hz; b. within [three] seconds following load rejection, the voltage is ≥ [3740] V and ≤ [4580] V. c. within [three] seconds following load rejection, the frequency is ≥ [58.8] Hz and ≤ [61.2] Hz.	[18 months]	no
3.8.1.10	Verify each diesel generator operating at a power factor ≤ [0.9] does not trip and voltage is maintained ≤ [5000] V during and following a load rejection of ≥ [4500] kW and ≤ [5000] kW.	18 months	no
3.8.1.11	Verify on an actual or simulated loss of offsite power signal: a. deenergization of emergency buses b. load-shedding from emergency buses c. diesel generator auto-starts from standby condition and 1. energizes permanently connected loads in ≤ [10] seconds 2. energizes auto-connected shutdown loads through [automatic load sequencer] 3. maintains steady state voltage ≥ [3740] V and ≤ [4580] V 4. maintains steady state frequency ≥ [58.8] Hz and ≤ [61.2] Hz 5. supplies permanently connected [and auto-connected] shutdown loads for ≥ 5 minutes.	[18 months]	no

SR Number	Surveillance Requirement	Frequency	Detects Aging Degradation?
3.8.1.12	Verify on an actual or simulated engineered safety feature actuation signal each diesel generator auto-starts from standby condition and: a. in ≤ [10] seconds after auto-start and during tests, achieves voltage ≥ [3740] V and ≤ [4580] V b. in ≤ [10] seconds after auto-start and during tests, achieves frequency ≥ [58.8] Hz and ≤ [61.2] Hz c. operates for ≥ 5 minutes d. permanently connected loads remain energized from the offsite power system e. emergency loads are energized [or auto-connected through the automatic load sequencer] to the offsite power system.	[18 months]	no
3.8.1.13	Verify each diesel generators automatic trips are bypassed on [actual or simulated loss of voltage signal on the emergency bus concurrent with an actual or simulated engineered safety feature actuation signal] except: a. engine overspeed b. generator differential current c. [low lube oil pressure] d. [high crankcase pressure] e. [start failure relay].	[18 months]	no
3.8.1.14	Verify each diesel generator operating at a power factor ≤ [0.9] operates for ≥ 24 hours: a. for ≥ [two] hours loaded ≥ [5250] kW and ≤ [5500] kW b. for the remaining hours of the test loaded ≥ [4500] kW and ≤ [5000] kW.	[18 months]	no
3.8.1.15	Verify each diesel generator starts and achieves, in ≤ [10] seconds, voltage ≥ [3740] V, and ≤ [4580] V and frequency ≥ [58.8] Hz and ≤ [61.2] Hz.	[18 months]	no
3.8.1.16	Verify each diesel generator: a. synchronizes with offsite power source while loaded with emergency loads upon a simulated restoration of offsite power b. transfers loads to offsite power source c. returns to ready-to-load operation.	[18 months]	no

SR Number	Surveillance Requirement	Frequency	Detects Aging Degradation?
3.8.1.17	Verify, with a diesel generator operating in test mode and connected to its bus, an actual or simulated engineered safety feature actuation signal overrides the test mode by: a. returning diesel generator to ready-to-load operation b. automatically energizing the emergency load from offsite power.	[18 months]	no
3.8.1.18	Verify interval between each sequenced load block is within ± [10% of design interval] for each emergency [and shutdown] load sequencer.	[18 months]	no
3.8.1.19	Verify on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated energy safety feature actuation signal: a. deenergization of emergency buses b. load-shedding from emergency buses c. diesel generator auto-starts from standby condition and 1. energizes permanently connected loads in ≤ [10] seconds 2. energizes auto-connected emergency loads through load sequencer 3. achieves steady state voltage ≥ [3740] V and ≤ [4580] V 4. achieves steady state frequency ≥ [58.8] Hz and ≤ [61.2] Hz 5. supplies permanently connected [and auto-connected] emergency loads for ≥ 5 minutes.	[18 months]	no
3.8.1.20	Verify when started simultaneously from standby condition, each diesel generator achieves, in ≤ [10] seconds, voltage ≥ [3744] V and ≤ [4576] V, and frequency ≥ [58.8] Hz and ≤ [61.2] Hz.	10 years	no
	Diesel Fuel Oil, Lube Oil, and Starting Air		
3.8.3.1	Verify each fuel oil storage tank contains ≥ [33,000] gal of fuel.	31 days	no
3.8.3.2	Verify lubricating oil inventory is ≥ [500] gal.	31 days	no
3.8.3.3	Verify fuel oil properties of new and stored fuel oil are tested in accordance with, and maintained within the limits of, the Diesel Fuel Oil Testing Program.	In accordance with the Diesel Fuel Oil Testing Program	yes
3.8.3.4	Verify each diesel generator air start receiver pressure is ≥ [225] psig.	31 days	yes
3.8.3.5	Check for and remove accumulated water from each fuel oil storage tank.	[31] days	no

SR Number	Surveillance Requirement	Frequency	Detects Aging Degradation?
3.8.3.6	For each fuel oil storage tank: a. drain the fuel oil b. remove the sediment c. clean the tank.	10 years	no

7.0 Motor-Operated Valves

Motor-operated valves (MOVs) are used extensively within Pressurized-Water Reactor (PWR) and Boiling-Water Reactor (BWR) nuclear power plants for service in safety-related and balance-of-plant systems. Principal types of MOVs used in nuclear power plants are listed in Table 7.1, along with typical systems where they may be found. Table 7.1 indicates the number of valves, valve size ranges, and valve types for various systems that are typically found in PWR and BWR plants. The most commonly used MOVs are gate, globe, and butterfly valves, although other types are also used. The valve operators discussed in this section are ac and dc motor-powered, geared-type valve actuation devices. A typical MOV that shows general areas where most aging degradation occurs is illustrated in Figure 7.1.

Failures of MOVs have compromised operational readiness in critical safety-related systems and also have required significant maintenance efforts. A comprehensive Nuclear Plant Aging Research (NPAR) assessment of MOVs (Greenstreet et al. 1985; Crowley and Eissenberg 1986; Haynes 1989; Haynes and Farmer 1992) has been conducted by Oak Ridge National Laboratory. This study identified the stressors and operative aging mechanisms for MOVs and evaluated methods to detect, differentiate, and trend the resulting aging degradation. The NPAR study provided the technical basis for the MOV standard technical specifications (STS) aging evaluation. Additional information on MOV aging processes and detection techniques was obtained from publications by Blahnik et al. (1992), Harmon and Johnsen (1992), Jarrell et al. (1992), McGough and Johnsen (1992), and Wood et al. (1992).

7.1 Motor-Operated Valve Description and Boundaries

For the purpose of this evaluation, the valve motor operator is defined as the motor and all subcomponents within the motor-operator housing (i.e., the gearbox assembly and the switch assembly). The valve is defined as the body assembly, internals, and seals. Not addressed in this report are the motor power supply and its protective devices, external power and signal cables, and remote MOV control circuit.

1. The valve includes the following subcomponents:

   - body assembly, which includes the body, bonnet, yoke, and fasteners
   - internals, which include the seat, disc/gate, disc/gate guide, stem, and stem packing
   - seals, which include gaskets and seals.

2. The motor operator is composed of the following subcomponents:

   - gearbox assembly, which include gears, shaft, bearings, clutch mechanism, handwheel, seals, lubricants, drive sleeve, spring pack, stem nut, lock nut, fasteners, and gearbox

- motor assembly, which includes the motor, stator, rotor, bearings, seals, gaskets, fan coolers, terminal block, heaters, windings, and insulation

- switch assembly, which includes terminal blocks, wiring, limit/torque switch, fasteners, and lubricants.

Table 7.1. Summary of MOV Applications in Nuclear Power Plants

System	Number of MOVs	Valve size (inches)	Valve type
BWR (typical)			
Low-pressure core spray	8 to 12	2 to 28	gate, globe
High-pressure coolant injection	8 to 14	4 to 24	gate, globe
Low-pressure coolant injection (including residual heat removal and containment spray)	28 to 50	4 to 24	gate, globe
Reactor recirculation system	8 to 10	2 to 28	gate
Reactor core isolation cooling	8 to 10	3 to 6	gate, globe
Containment isolation	4 to 14	3 to 24	butterfly, gate
Balance-of-plant systems	50 to 150	2 to 60	gate, globe, butterfly
PWR (typical)			
Auxiliary feedwater	6 to 10	4 to 8	globe
Chemical and volume control	8 to 10	3 to 8	gate
Containment spray	8 to 12	6 to 14	gate, globe, butterfly
Diesel generator cooling	8 to 10	4 to 12	globe
High-pressure coolant injection	10 to 24	2 to 4	globe
Heating, venting, and air conditioning	6 to 10	6 to 48	butterfly
Low-pressure coolant injection/ residual heat removal	12 to 30	8 to 10	gate
Safety injection	15 to 54	3 to 14	gate
Balance-of-plant systems	50 to 150	2 to 60	gate, globe, butterfly

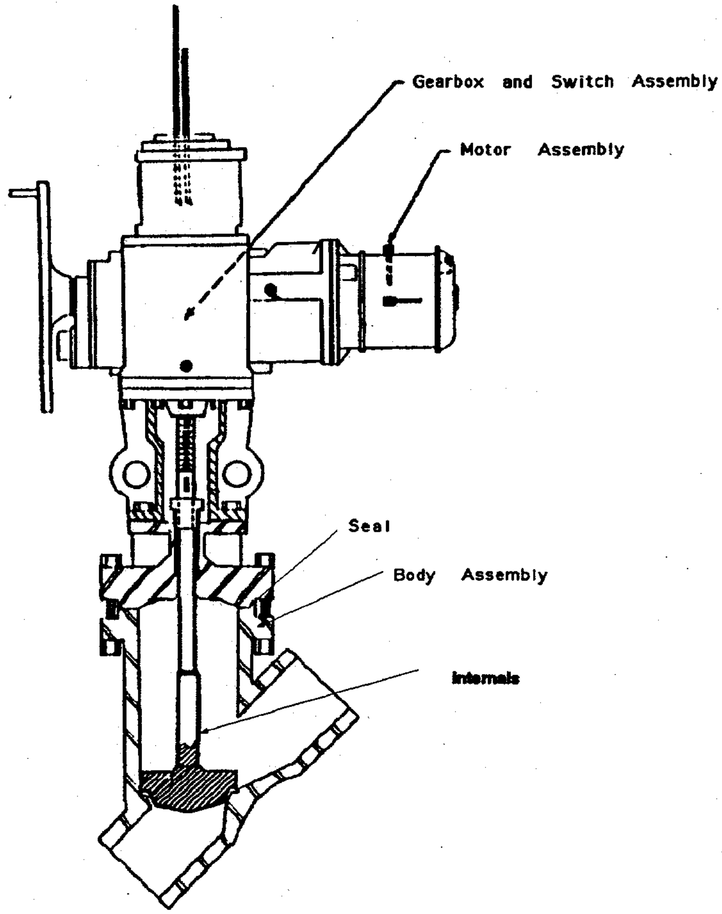

Figure 7.1. Typical Motor-Operated Valve

7.2 Stressors, Aging Mechanisms, and Aging Effects

Motor-operated valve stressors, aging mechanisms, aging effects, and the MOV system locations where the stressors and aging mechanisms are operative are summarized in Table 7.2 for each major MOV subcomponent. The stressors and aging mechanisms of MOVs include thermal stresses, adverse environmental conditions, improper or excessive voltages and currents, radiation, vibration, ohmic heating, dirt or dust contamination, vibration-induced fatigue, mechanical stress abrasions, corrosion, oxidation, cracking, and embrittlement. Inadequate maintenance also can contribute to premature degradation of MOVs. The overall impact of these degradation mechanisms has plant-specific applications.

Also delineated in Table 7.2 is whether or not a particular aging degradation effect is detected by the current surveillance requirements (SRs). A representative SR is cited for those aging effects that are detectable; more than one SR may be applicable. A potential deficiency in the STS is identified when a particular aging effect is not detected by any existing SR (i.e., the MOV subcomponent may

Table 7.2. Summary of Detection Capability of Current SRs

MOV Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Methods	Addressed by STS SRs?[(a)]	Addressed by GL 89-10?[(b)]
A. Body Assembly						
body	vibration	fatigue	loss of strength	analysis	no	no
	thermal-cycling	thermal fatigue	loss of strength	analysis	no	no
	chemicals	corrosion	thinning, pitting	internal visual	no	no
body, bonnet	flow	erosion	wall-thinning	external visual for leakage	3.4.14.1	no
				analysis for thinning	no	
		cavitation	pitting, wall-thinning	internal visual	no	
				analysis for thinning	no	
	external environmental conditions (e.g., temperature, humidity, chemicals)	oxidation	loss of strength	analysis	no	no
		corrosion	wall-thinning	external visual for leakage	3.4.14.1	
				analysis for thinning	no	
	water hammer	fatigue	cracking	external visual for leakage	3.4.14.1	no
	pressure cycles	fatigue	cracking	external visual for leakage	3.4.14.1	no
yoke bushing	operation	wear	binding, loosening	visual, MOV diagnostic system (MOV-DS)	no	no
fasteners	vibration	fatigue	loosening	external visual for leakage	3.4.14.1	no
				internal visual	no	
		galling	fracture, seizure	disassembly	no	
	thermal-cycling	differential thermal expansion	loosening	external visual for leakage	3.4.14.1	no
	external environmental conditions (e.g., temperature, humidity, chemicals)	stress corrosion	cracking, fracture	disassembly	no	no
				external visual for leakage	3.4.14.1	

(a) Representative SRs are listed where applicable.
(b) Numbers in this column refer to the MOV problems listed in Table 7.3.

Table 7.2. (contd)

MOV Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Methods	Addressed by STS SRs?[a]	Addressed by GL 89-10?[b]
B. Internals						
seat	operation	abrasion, wear	cracking, distortion	visual, analysis for internal leakage, MOV-DS	no	no
disc/gate, disc/gate guide, seat	operation	wear, galling	loosening, binding interferences	visual, MOV-DS	no	15
disc/gate, disc/gate guide, seat, stem, stem packing	chemicals	corrosion	thinning, cracking, interferences	visual, analysis for internal leakage, MOV-DS	no	no
	flow	erosion	thinning, loosening, interferences, cracking	visual, analysis for thinning or internal leakage, MOV-DS	no	no
stem	external environmental conditions (e.g., temperature, humidity, chemicals)	corrosion	wear-reduction, binding	external visual for leakage	3.4.14.1	9
				MOV-DS	no	
	steam	erosion	wear-reduction, binding	external visual for leakage	3.4.14.1	9
				MOV-DS	no	
stem, stem packing	operation	wear, fatigue, creep	loosening, breakdown	visual, MOV-DS	no	10
stem packing	heat	embrittlement, wear	cracking, distortion	visual, MOV-DS	no	no
				external visual for leakage	3.4.14.1	
	radiation	embrittlement, wear	cracking, distortion	visual, MOV-DS	no	no
				external visual for leakage	3.4.14.1	
C. Seals						
seals, gaskets	operation	abrasion, wear, erosion	cracking, breakdown	external visual for leakage	3.4.14.1	no
				MOV-DS	no	no
	heat	embrittlement	cracking, distortion	external visual for leakage	3.4.14.1	no
	radiation	embrittlement	cracking, distortion	external visual for leakage	3.4.14.1	no

(a) Representative SRs are listed where applicable.
(b) Numbers in this column refer to the MOV problems listed in Table 7.3.

Table 7.2. (contd)

MOV Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Methods	Addressed by STS SRs?[a]	Addressed by GL 89-10?[b]
D. Gearbox Assembly						
gears, bearings, drive sleeve	operation	wear, fatigue	loosening, interferences	visual, MOV-DS	no	11, 12
				operation	3.5.2.5	
bearings	contamination	corrosion	binding, increase in frictional resistance	visual, MOV-DS	no	22
				operation	3.5.2.5	
fasteners, stem nut, lock nut	vibration	fatigue, wear	loosening	visual	no	7
				operation	3.5.2.5	
shaft	vibration	wear, galling	loosening, distortion, sticking	visual, MOV-DS	no	no
				operation	3.5.2.5	
clutch	vibration	wear, fatigue	loosening, sticking, binding	visual, MOV-DS	no	19
				operation	3.5.2.5	
spring pack	operation	fatigue	response change	MOV-DS	no	no
				operation	3.5.2.5	
seals	radiation	embrittlement	cracking, distortion	visual	no	no
	heat	wear, embrittlement	cracking, distortion	visual	no	no
lubricant	contamination	fouling	hardening, breakdown	visual, MOV-DS	no	12
				operation	3.5.2.5	
	heat	oxidation	breakdown, hardening	visual, MOV-DS	no	12
				operation	3.5.2.5	
E. Motor Assembly						
contacts, windings	ohmic heating	oxidation, embrittlement	shorting, increase in electrical resistance	resistance bridge testing	no	no
contacts	overvoltage operation; spikes, transients, etc.	arcing, wear	shorting, fracture	visual, MOV-DS	no	no
				operation	3.5.2.5	
	vibration	fatigue, wear	loosening, fracture	torque verification	no	no

(a) Representative SRs are listed where applicable.
(b) Numbers in this column refer to the MOV problems listed in Table 7.3.

Table 7.2. (contd)

MOV Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Methods	Addressed by STS SRs?[(a)]	Addressed by GL 89-10?[(b)]
motor	mechanical overload	overheating	loss of rated torque output, seizure	operation	3.5.2.5	17
				visual, polarization index, resistance bridge test, MOV-DS	no	
	overvoltage operation; spikes, transients, etc.	arcing	shorting	operation	3.5.2.5	13,14
				MOV-DS, resistance bridge test	no	
rotor	ohmic heating	corrosion	cracking, softening, melting	waveform analysis, visual	no	13
stator	overvoltage operation	fatigue	breakdown, shorting	MOV-DS, resistance bridge testing, polarization index	no	no
	undervoltage and single phase operation	overheating	breakdown	polarization index testing, resistance bridge test	no	28
	voltage imbalance	overheating	breakdown	resistance bridge test, polarization index	no	no
bearings	overvoltage operation	wear, oxidation	breakdown, seizure	MOV-DS	no	22
	operation	wear	loosening, interferences	MOV-DS	no	22
moisture seal	external environmental conditions	corrosion	cracking, breakdown	visual	no	16
insulation	undervoltage and single phase operation	embrittlement	breakdown, fracture	visual, polarization index testing, resistance bridge test	no	14
	voltage imbalance	embrittlement	loss of dielectric strength, fracture, breakdown	polarization index testing, resistance bridge test	no	14
	mechanical overload	embrittlement	loss of dielectric strength, fracture, breakdown	visual, polarization index testing, resistance bridge test	no	14
	radiation	embrittlement	loss of dielectric strength, fracture, breakdown	visual, polarization index testing, resistance bridge test	no	14

(a) Representative SRs are listed where applicable.
(b) Numbers in this column refer to the MOV problems listed in Table 7.3.

Table 7.2. (contd)

MOV Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Methods	Addressed by STS SRs?[a]	Addressed by GL 89-10?[b]
insulation (contd)	external environmental conditions	embrittlement	loss of dielectric strength, fracture, breakdown	polarization index testing, resistance bridge test	no	14, 16
	overvoltage operation	embrittlement	loss of dielectric strength, breakdown, fracture	polarization index testing, resistance bridge test	no	14
F. Switch Assembly						
contacts	operation	pitting	increase in electrical resistance, overheating	visual, MOV-DS	no	no
				operation	3.5.2.5	
	overvoltage operation	pitting, arcing	increase in electrical resistance, shorting, breakdown	visual, MOV-DS	no	20
				operation	3.5.2.5	
	external environmental conditions (e.g., temperature, humidity, chemicals)	oxidation	increase in electrical resistance, contamination	visual, MOV-DS	no	16, 20
				operation	3.5.2.5	
		corrosion	increase in electrical resistance, interferences, increase in frictional resistance, contamination	visual, MOV-DS	no	no
				operation	3.5.2.5	
set points	operation	drift	sticking open/shut	MOV-DS	no	1, 2, 8, 21
gears, cam	operation	wear	loosening, binding	visual, MOV-DS	no	11
fasteners	vibration	fatigue	loosening	visual	no	no
insulation	external environmental conditions	embrittlement	loss of dielectric strength, breakdown, fracture	visual, MOV-DS	no	14
	thermal	embrittlement	loss of dielectric strength, breakdown, fracture	resistance bridge test	no	14
	radiation	embrittlement	loss of dielectric strength, fracture, breakdown	visual, MOV-DS	no	14
grease	heat	fouling	hardening	MOV-DS	no	12

(a) Representative SRs are listed where applicable.
(b) Numbers in this column refer to the MOV problems listed in Table 7.3.

experience undetected degradation). A list of recommended SRs to address the undetected degradation is presented in Section 7.6. Degradation effects that are more appropriately addressed by an effective maintenance program (e.g., fastener loosening and seal cracking or distortion) are not included.

The stressors, aging mechanisms, and resultant aging effects for MOV subcomponents are as follows:

1. Body Assembly

   - fatigue from mechanical stress due to water hammer events
   - fatigue from hydraulic stress due to system pressure
   - yoke bushing frictional wear due to operation
   - fastener (e.g., bonnet-bolting, packing-gland bolting) loosing due to vibrational loads and differential thermal expansion
   - fatigue due to vibration
   - corrosion, either internal or external, due to boric acid
   - oxidation, corrosion, and stress corrosion due to high ambient temperature and humidity
   - erosion and cavitation due to fluid flow.

2. Internals

   - disc/gate, disc/gate guide, and stem frictional wear, erosion, and corrosion due to operation and ambient conditions
   - disc/gate guide galling
   - seat frictional wear, erosion, abrasion, and corrosion
   - stem-packing frictional wear, erosion, and corrosion due to operation and operating parameters, and degradation due to thermal and radiation embrittlement
   - erosion of the valve stem due to high-pressure steam or water leaking through stem packing
   - valve stem corrosion due to high ambient temperature and humidity.

3. Seals

   - seal and gasket frictional wear or degradation due to normal operation
   - cracking due to thermal and radiation embrittlement.

The stressors, aging mechanisms, and aging effects for motor operator subcomponents are as follows:

1. Gearbox Assembly

   - gear frictional wear
   - fastener loosening due to vibrational loads
   - stem nut and drive sleeve frictional wear
   - bearing frictional wear and corrosion
   - lubricant degradation and hardening due to thermal effects and contamination (dirt, rust, etc.)
   - shaft frictional wear and distortion due to vibrational loads
   - clutch mechanism frictional wear
   - spring-pack response changes
   - stem lock-nut loosening
   - seal wear and degradation due to thermal and radiation embrittlement.

2. Motor Assembly

   - bearing wear and oxidation
   - corona attack and dielectric breakdown of electrical insulation due to mechanical overload, radiation and thermal embrittlement, voltage imbalance, and undervoltage, overvoltage, and single-phase operation
   - increased ohmic heating due to electrical stresses, such as inductive surges and overvoltage operation
   - arcing of contacts due to overvoltage operation
   - stator fatigue and overheating due to electrical stresses
   - motor overheating due to overload
   - fatigue and wear due to vibration
   - oxidation and embrittled connections due to ohmic heating
   - winding oxidation and embrittlement due to ohmic heating

- moisture seal corrosion due to high temperatures and humidity.

3. Switch Assembly

- contact pitting, oxidation, and corrosion due to operation and environmental conditions, and arcing due to overvoltage operation
- electrical insulation breakdown due to environmental conditions and thermal and radiation embrittlement
- grease hardening due to heat or radiation damage
- set-point drift due to operation
- gear and cam frictional wear
- fastener loosening due to vibrational loads
- accelerated corrosion, interferences, and increased frictional forces and resistances due to elevated ambient temperatures, humidity, dust, dirt, and contamination.

7.3 Degradation Detection Methods

Several methods that are effective in detecting aging degradation have been developed, either historically or in response to specific aging concerns. The specific detection methods that are applicable to MOV aging degradation are identified in Table 7.2. While some traditional methods, such as MOV operation and examination for leakage, are implemented in the current SRs, a much broader assortment of methods are available for use in detecting MOV aging degradation. Those methods that are useful and appropriate for inclusion in the SRs are identified in Section 7.6 as recommendations to improve and supplement the SRs. A discussion of these detection methods is presented in Appendix 7B.

7.4 Evaluation of Existing Surveillance Requirements for Effectiveness in Detecting Aging Degradation

The STS specify overall inspection and testing requirements for safety-related systems and components. American Society of Mechanical Engineers (ASME) Class 1, 2, and 3 components are required to be inspected and tested in accordance with Section XI, ASME Boiler and Pressure Vessel Code. Section XI requires that MOV testing involve only two parameters: stroke time and seat leakage. These two MOV testing requirements are reflected in the SRs. This testing is a useful tool to determine MOV condition as a result of aging degradation (e.g., valve degradation may be indicated by variations in measured stroke times). However, testing is usually performed without fluid pressure or flow in associated piping. Under these conditions, severe degradation of MOVs may occur without significant changes in stroke times. Thus, testing at zero differential pressure or no-flow conditions may not be sufficient to provide assurance of MOV condition. Existing SRs focus on operability concerns and not on condition monitoring to detect and trend aging degradation. See Appendix 7B for examples of SRs related to MOVs. Of the 40 SRs in one typical STS, two pertain to leakage, 20 to operation, and 18 to status verification. This focus of existing SRs is a problem from a safety perspective; recent studies show that, as plants age, the failure rate of MOVs increases. The historical attitude has been that MOVs get attention when testing indicates that something (e.g., leakage) is wrong with them.

7.5 Evaluation of Existing Surveillance Requirements for Possible Contributions to Premature Aging Degradation

As noted in Section 7.4, the existing SRs for MOV are designed primarily to determine operability and not to detect and trend aging degradation. Most SRs require **verification** of a condition or status, such as verifying valve position, which generally would have no aging impact. The few SRs that require **demonstration** or **operation** are on such a low frequency as to render their aging effects negligible. Thus, existing SRs for MOVs do not contribute to aging in that the test methods and the frequency of testing do not cause premature aging degradation.

7.6 Recommendations to Improve/Supplement Surveillance Requirements

7.6.1 Generic Letter 89-10

Generic Letter (GL) 89-10, "Safety-Related Motor-Operated Valve Testing," dated June 28, 1989, and provided in Appendix 7C, identified some common deficiencies, misadjustments, and degraded conditions of MOVs, these are listed in Table 7.3. GL 89-10 recommends the development and implementation of a program to ensure that the switch settings of specified MOVs are selected, set, and maintained such that the MOVs will operate under design-basis conditions for the life of the plant. The scope of the GL includes maintenance and design concerns in addition to aging concerns. The GL addresses MOV testing, inspection, and maintenance requirements and contains specific recommended actions to be taken to address many MOV problems. These recommended actions are intended to confirm that MOVs will perform their intended functions under design-basis and normal operating conditions for the life of the plant.

Six supplements to the GL have been published to date, which reflect the increased amount of attention and effort that MOVs are now receiving. Supplement 1 addresses the results of U.S. Nuclear Regulatory Commission (NRC)-sponsored public workshops regarding the MOV programs. Supplement 2 addresses required establishment dates for utility MOV programs. Supplement 3 addresses the results of MOV testing. Supplement 4 addresses the position-changeable valves in BWRs. Supplement 5 addresses MOV diagnostic equipment accuracy. Supplement 6 addresses NRC response to public questions.

Table 7.3. Common MOV Deficiencies, Misadjustments, and Degraded Conditions Identified in Generic Letter 89-10

1. Incorrect torque-switch bypass setting
2. Incorrect torque-switch setting
3. Unbalanced torque switch
4. Spring-pack gap or incorrect spring-pack preload
5. Incorrect stem-packing tightness
6. Excessive inertia
7. Loose or tight stem-nut locknut
8. Incorrect limit-switch settings
9. Stem wear
10. Bent or broken stem
11. Worn or broken gears
12. Grease problems: hardening, migration to spring pack, lack of grease, excessive grease, contamination, nonspecified grease
13. Motor insulation or rotor degradation
14. Incorrect wire size or degraded wiring
15. Disk/seat binding, including thermal binding
16. Water in internal parts or resulting degradation
17. Motor undersized for degraded voltage or other conditions
18. Incorrect valve position indication
19. Misadjustment or failure of handwheel declutch mechanism
20. Relay problems incorrect or miswired relays, contamination, deteriorated relays
21. Incorrect thermal overload switch settings
22. Worn or broken bearings
23. Broken or cracked limit-switch and torque-switch settings
24. Missing or modified torque-switch limiter plate
25. Improperly sized actuators
26. Hydraulic lockup
27. Incorrect metallic materials for gears, keys, bolts, shafts, etc.
28. Degraded voltage, within design limits
29. Defective motor control logic
30. Excessive seating or backseating force application
31. Incorrect reassembly or adjustment after maintenance or testing
32. Unauthorized modifications or adjustments
33. Torque-switch or limit-switch binding degradation

In Table 7.2, a large number of significant aging degradation effects are identified that are applicable to MOVs, as well as appropriate detection methods. Many of these effects are not addressed by current SRs. With implementation of an MOV program in response to the GL, an additional number of aging degradation effects may be addressed. Thus, the remainder of aging degradation effects, which are not addressed by either current SRs or the GL, will be addressed by NPAR recommendations. The following GL 89-10 recommendations are presented for incorporation into SRs.

1. Perform a dynamic test of a representative sample of safety-related and position-changeable MOVs, as a minimum, at or near design-basis conditions at least once every five years, to demonstrate design-basis capability. Testing of MOVs at design-basis conditions need not be repeated unless the MOV is replaced, modified, or overhauled to the extent that the licensee considers that the existing test results are not representative of the MOV in its modified configuration.

2. When a dynamic test at or near design-basis conditions is not practical due to plant configuration or MOV operability considerations, perform a test of a representative sample of safety-related and position-changeable MOVs at low differential pressure or low flow, as appropriate, at least once every five years, to demonstrate design-basis capability.

7.6.2 Recommendations from the NPAR Motor-Operated Valve Aging Assessment

Specific NPAR studies related to MOVs have made additional recommendations that address MOV age-related problems. Not every degradation method that is identified in Table 7.2 is appropriate for inclusion in SRs. For example, analysis of the MOV body or bonnet for loss of strength due to fatigue, thermal fatigue, or oxidation is not recommended because such degradation is of such a low degree as to pose no genuine MOV aging concern to utilities. Torque verification for fastener tightness is a detection method that is better suited for inclusion in a maintenance program than in the STS.

Diagnostic systems for motor-operated valves should be used to determine and trend the aging characteristics of the MOVs. These diagnostic systems should be incorporated into the SRs that test dynamic operation of the MOVs. It may not be practical to test each MOV. An acceptable response to this situation is to group similar MOVs in a manner that provides adequate confidence that all MOVs are capable of performing their design-basis function. In selecting the above-recommended representative samples, the sample size should be nominally 30 percent of the group, or no less than two MOVs. To the extent practicable, MOVs to be tested should be selected on a prioritization that considers the greatest safety significance (i.e., risk significance to core damage frequency) or least performance margin. In grouping MOVs, such similarities as manufacturer, model, size, flow, temperature, pressure, hydraulics, configuration, material condition, and performance should be considered. The NRC stated in GL 89-10, Supplement 1 that "The [NRC] does not intend to specify the parameters that must be measured or the diagnostic system that a licensee should use." The following recommendations are made to address aging issues in SRs, making them more useful and effective to detect, trend, and monitor degradation conditions of MOVs before failure and are presented for incorporation into SRs.

1. A representative sample of MOVs should be visually examined once every third refueling cycle, or whenever opened for any other reason, for evidence of aging degradation (i.e., binding, breakdown, cracking, distortion, fracture, hardening, interferences, loosening, pitting, seizure, shorting, sticking, thinning, or wear). When evidence of thinning is detected[a], an analysis of the MOV should be performed to determine the extent of thinning and the serviceable life remaining to the MOV.

2. Motor current signature analysis, which is one MOV diagnostic system, has been found to provide detailed information related to the condition of the motor, motor operator, and valve, across a wide range of levels from mean values and gross variations during valve operation to information that characterizes transients and periodic occurrences. Motor current signature analysis or an equivalent should be incorporated into SRs on a representative sample of MOVs at least once each refueling cycle. Motor current signature analysis is not, in itself, a good predictor of aging degradation; it is limited in that it provides qualitative information on valve condition, but not the quantitative information needed to evaluate MOV operability.

3. Other systems of MOV diagnostic analysis that complement motor current signature analysis have been found to provide a wide range of information on aging degradation. Specifically, these systems can trend parameters (stem thrust is a primary one, although stem torque and motor control center voltage should also be measured) that demonstrate that MOV subcomponents are free of evidence of binding, breakdown, cracking, distortion, fracture, hardening, increase in frictional resistance, interferences, loosening, response change, seizure, shorting, sticking, and wear. These complementary MOV diagnosis systems should be incorporated into SRs on a representative sample of MOVs at least once per refueling cycle.

4. Polarization index testing and resistance bridge testing of a representative sample of MOV motor assemblies should be performed once every refueling cycle for evidence of aging degradation (e.g., breakdown, fracture, overheating, or shorting).

5. Motor current waveform analysis of a representative sample of MOV motor assemblies should be performed once every refueling cycle for evidence of rotor corrosion, cracking, softening, or melting.

6. A systematic method for determining root cause of a component failure was developed for the service water system as part of the NPAR program (Jarrell et al. 1992). This methodology focuses resources on mitigating the underlying cause of failure, rather than the treatment of an indicating symptom. A utility-specific version of this approach should be incorporated into the SR framework for risk-significant MOVs.

(a) Generic Letter 89-08, "Erosion-Corrosion Induced Pipe Wall Thinning," dated May 2, 1989, recommends the implementation of an erosion-corrosion monitoring program for piping and components within the licensing basis to ensure that erosion-corrosion does not lead to the degradation of single-phase and multiphase high-energy carbon steel systems. The actions in the recommendation for MOV thinning are encompassed within the details of this erosion-corrosion program.

7.6.3 Implementing Suggested Requirements

A list of suggested SRs for MOVs with associated surveillance frequencies that combines the requirements of GL 89-10 and NPAR is provided in Table 7.4. These recommended SRs correct the weakness for potential undetected MOV subcomponent degradation in the STS that was identified in Table 7.2, except for those effects with a very low probability of failure of the associated subcomponent or those that are more appropriately addressed by an effective maintenance program.

An SR is not specified below for each individual MOV subcomponent; rather, the individual degradation detection methods that apply to a particular degradation effect on a subcomponent are grouped to form a generically stated SR. For example, each visual examination that is deemed appropriate to detect a potential undetected MOV subcomponent degradation effect, as reflected in Table 7.2, is combined into a single recommended SR in Table 7.4. Each of these generic SRs would then be expanded by writing them for MOVs and MOV subcomponents throughout the STS in a form consistent with that of existing SRs, as identified in Appendix 7B.

Table 7.4. Surveillance Requirement Recommendations to Detect and Trend MOV Aging Degradation

Surveillance Requirement[a,b]	Frequency of Action
Trend parameters (e.g., by means of an MOV diagnostic system) that demonstrate the design basis capability of safety-related and position-changeable MOVs by monitoring one or more of the following parameters: • motor current • valve stem position, torque, and thrust • spring pack displacement • time of actuation of all control switches • motor voltage and power • actuator vibration and output torque	18 months or whenever tested
Trend parameters (e.g., by means of an MOV diagnostic system) that demonstrate the design-basis capability of safety-related and position-changeable MOVs will not be impeded (present or future) by the following degradation effects: • binding • cracking • fracture • increase in frictional resistance • interferences • response change • sticking • shorting • wear • breakdown • distortion • hardening • loosening • seizure	18 months or whenever tested

(a) In the event of MOV failure, root-cause analysis of the MOV should be performed to determine the underlying cause of failure.

(b) These SRs apply to a representative sample of MOVs, prioritized by risk significance to core damage frequency. In the event that failure is detected, additional MOVs within that sample should be examined.

(c) In the event that thinning of any MOV subcomponent is detected, an analysis of the MOV and associated piping should be performed to determine the extent and rate of thinning.

(d) Those MOVs whose safety function is to fail as-is are not required to demonstrate operability.

(e) In the event that testing at or near design-basis conditions is not practical due to reasons of plant configuration or MOV operability. Those MOVs whose safety function is to fail as-is are not required to demonstrate operability.

Surveillance Requirement[a,b]	Frequency of Action
Perform visual examination of MOV accessible subcomponents (inaccessible MOV subcomponents should be subject to this visual examination when made accessible for any other reason or when warranted by other SR indication) to verify that MOV design-basis operation will not be affected (present or future) by debris accumulation or excessive degradation, e.g.: • binding • breakdown • cracking • distortion • fracture • hardening • interferences • loosening • pitting • seizure • shorting • thinning[c] • wear	36 months or whenever opened
Verify (e.g., by means of polarization index testing, resistance bridge testing, waveform analysis, or visual examination) that MOV electrical subcomponents will not be affected (present or future) by the following degradation effects: • breakdown • loosening • overheating • shorting • fracture • seizure • increase in electrical resistance • loss of dielectric strength	36 months or whenever opened
Demonstrate the design-basis capability, through dynamic test, extrapolation from static test, or an accepted predictive methodology, of safety-related and position-changeable MOVs at or near design-basis conditions[d]	60 months
Demonstrate the design-basis capability, through dynamic test, extrapolation from static test, or an accepted predictive methodology, of safety-related and position-changeable MOVs at low differential pressure or low-flow conditions[e]	60 months

(a) In the event of MOV failure, root-cause analysis of the MOV should be performed to determine the underlying cause of failure.
(b) These SRs apply to a representative sample of MOVs, prioritized by risk significance to core damage frequency. In the event that failure is detected, additional MOVs within that sample should be examined.
(c) In the event that thinning of any MOV subcomponent is detected, an analysis of the MOV and associated piping should be performed to determine the extent and rate of thinning.
(d) Those MOVs whose safety function is to fail as-is are not required to demonstrate operability.
(e) In the event that testing at or near design-basis conditions is not practical due to reasons of plant configuration or MOV operability. Those MOVs whose safety function is to fail as-is are not required to demonstrate operability.

Appendix 7A

Summary of Motor-Operated Valve Surveillance Requirements from Westinghouse STS

SR Number	Surveillance Requirement	Frequency	Detects Aging Degradation?
	Valve Operability		
3.4.11.1	Perform a complete cycle of each block valve.	92 days	no
	Seat/Body Leakage		
3.4.14.1	Verify leakage from each reactor coolant system pressure isolation valve is equivalent to $\leq$ 0.5 gpm per nominal inch of valve size up to a maximum of 5 gpm at a reactor coolant system pressure $\geq$ 2215 psig and $\leq$ 2255 psig.	18 months	yes
3.6.3.7	Perform leakage rate testing for containment purge valves with resilient seals.	184 days	yes
	Interlock - Valve Operation		
3.4.14.2	Verify residual heat removal system autoclosure interlock prevents the valves from being opened with a simulated or actual reactor coolant system pressure signal $\geq$ 425 psig.	18 months	no
3.4.14.3	Verify residual heat removal system autoclosure interlock causes the valves to close automatically with a simulated or actual reactor coolant system pressure signal $\geq$ 600 psig.	18 months	yes
	Valve Position		
3.4.17.1	Verify each reactor coolant system loop isolation valve is open and power is removed from each loop isolation valve operator.	31 days	no
3.5.1.1	Verify each accumulator isolation valve is fully open.	12 hours	no
3.5.2.1	Verify the following valves are in the listed position with power to the valve operator removed.	12 hours	no
3.5.2.2	Verify each emergency core cooling system manual, power-operated, and automatic valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days	no
3.5.2.7	Verify, for each emergency core cooling system throttle valve listed below, each position stop is in the correct position.	18 months	no
3.6.6A.1 3.6.6B.1 3.6.6C.1	Verify each core spray manual, power-operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position.	31 days	no

SR Number	Surveillance Requirement	Frequency	Detects Aging Degradation?
3.6.6D.1	Verify each quench spray manual, power-operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position.	31 days	no
3.6.6E.4	Verify each recirculation spray and casing cooling manual, power-operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position.	31 days	no
3.6.7.1	Verify each spray additive manual, power-operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position.	31 days	no
3.7.5.1	Verify each auxiliary feedwater manual, power-operated, and automatic valve in each water flow path, and in both steam supply flow paths to the steam turbine driven pump, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days	no
3.7.7.1	Verify each component cooling water manual, powered-operated, and automatic valve in the flow path servicing safety-related equipment, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days	no
3.7.8.1	Verify each service water system manual, power-operated, and automatic valve in the flow path servicing safety-related equipment, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days	no
3.9.2.1	Verify each valve that isolates unborated water sources is secured in the closed position.	31 days	no
	Power Removed		
3.5.1.5	Verify power is removed from each accumulator isolation valve operator when pressurizer pressure is $\geq$ 2000 psig.	31 days	no
	Positioning on Actual Signal		
3.5.2.5	Verify each emergency core cooling system automatic valve in the flow path actuates to the correct position on an actual or simulated actuation signal.	18 months	yes
3.6.3.8	Verify each automatic containment isolation valve actuates to the isolation position on an actual or simulated actuation signal.	18 months	yes
3.6.6A.5 3.6.6B.5 3.6.6C.3	Verify each core spray automatic valve in the flow path actuates to the correct position on an actual or simulated actuation signal.	18 months	yes
3.6.6D.3	Verify each quench spray automatic valve in the flow path actuates to the correct position on an actual or simulated actuation signal.	18 months	yes
3.6.6E.6	Verify each recirculation spray automatic valve in the flow path actuates to the correct position on an actual or simulated actuation signal(s).	18 months	yes
3.6.7.4	Verify each spray additive automatic valve in the flow path actuates to the correct position on an actual or simulated actuation signal.	18 months	yes

SR Number	Surveillance Requirement	Frequency	Detects Aging Degradation?
3.7.5.3	Verify each auxiliary feedwater automatic valve actuates to the correct position on an actual or simulated actuation signal when in MODE 1, 2, or 3.	18 months	yes
3.7.7.2	Verify each component cooling water automatic valve in the flow path actuates to the correct position on an actual or simulated actuation signal.	18 months	yes
3.7.8.2	Verify each service water system automatic valve in the flow path actuates to the correct position on an actual or simulated actuation signal.	18 months	yes
3.9.4.2	Verify each required containment purge and exhaust valve actuates to the isolation position on an actual or simulated actuation signal.	18 months	yes
	Isolation Time		
3.6.3.5	Verify the isolation time of each power-operated and each automatic containment isolation valve is within limits.	92 days	yes
	Restrict Opening		
3.6.3.10	Verify each containment purge valve is blocked to restrict the valve from opening > 50%.	18 months	no
	Train Actuation		
3.6.11.3	Verify each instrument control system train actuates on an actual or simulated actuation signal.	18 months	yes
	Low Path Alignment		
3.7.5.5	Verify proper alignment of the required auxiliary feedwater flow paths by verifying flow from the condensate storage tank to each steam generator.	Before entering MODE 2, whenever unit has been in MODE 5 or 6 for > 30 days	yes
	Loop Operation		
3.9.5.1	Verify one residual heat removal loop is in operation and circulating reactor coolant at a flow rate of $\geq$ 2800 gpm.	12 hours	yes
3.9.6.1	Verify one residual heat removal loop is in operation and circulating reactor coolant at a flow rate of $\geq$ 2800 gpm.	12 hours	yes

Appendix 7B

Discussion of Aging Degradation Detection Methods

Disassembly and examination of MOVs should provide acceptable information regarding MOV aging degradation, though at a heavy cost to the plant in terms of scheduling, radiation exposure, and time required. The potential also exists that an error could be made during valve during maintenance and reassembly. However, this method is the only way that some aging degradation can directly be detected (e.g., grease problems, water in internal parts, and broken or cracked switch subcomponents). Consequently, this method should not be entirely ruled out.

Motor-operated valve monitoring systems that are capable of providing information that is useful in assessing MOV aging have been developed over the last several years, thus helping to meet some of the requirements of GL 89-10. These systems operate by making measurements of one or more MOV parameters, providing graphical displays for analysis, and producing detailed quantitative information related to the motor, motor operator, and MOV across a wide range of levels, including mean values, gross variations during valve strokes, transients, and periodic events. These systems have the capability to identify both type and location of MOV problems to enhance corrective action. They generally monitor one or more of the following parameters:

- valve stem position, torque, and thrust
- spring-pack displacement
- time of actuation of control switches
- motor current, voltage, and power
- actuator vibration and output torque.

While many MOV diagnostic systems that are commercially available monitor similar parameters (e.g., motor current, spring-pack displacement), they use different transducers and signal-conditioning equipment to provide varying levels of signature analysis (interpretation). Only one MOV measurable parameter (motor current) is monitored by all commercial systems. Motor current monitoring may be performed remotely and nonintrusively and provides much information related to the condition of the motor, motor operator, and MOV, although the level of information extracted from MOV motor current signals varies from system to system. Valve stem thrust is also commonly monitored.

Motor current signature analysis is an example of a diagnostic method that is effective and easily performed, though other diagnostic systems have since been developed that may be less subjective and more effective yet. However, the use of other monitoring methods can aid in the analysis process, and respond to most stressors and aging mechanisms noted above. Since each MOV measurable parameter provides different and complementary information, simultaneous monitoring of more than one of these parameters can provide additional diagnostic details unavailable from any one measurement. For example, an unusually high running current may indicate increased running loads, although the precise source of the increase may be difficult to determine from motor current measurements alone. A simultaneously observed increase in stem thrust would suggest that the increase in running load was due to the valve (e.g., from increased packing tightness or from increased rubbing within the valve) rather than from within the motor operator. Conversely, if stem thrust levels are normal, increased friction from gears, bearings, etc., within the motor operator may be the cause. In that regard, MOV diagnostics provided by these commercial systems are strongly based on concurrent analyses of several signatures. These systems can be used effectively to respond to some deficiencies and degraded conditions listed in GL 89-10.

Polarization index testing is a practice used to assess the quality, cleanliness, and integrity of electrical insulation. A voltage is applied across the insulation for a specified duration; insulation-resistance readings are recorded at specified intervals. The ratio of successive readings may be compared to established criteria in order to determine the viability of the insulation under test. Utilities use polarization index testing for critical power plant machines, especially in high humidity/moisture and dusty environments, during outages to determine the need for cleaning, repair, or replacement, or to establish that the insulation should not fail during the scheduled duration of power plant operation. Trending of polarization index test data and correlation of the trended data with service conditions may facilitate assessment of the rate at which aging degradation affects insulation under specific service conditions. Comparison of test data with typical values for new insulation similar in style to that under test should reveal the extent to which aging degradation has degraded insulation, when insufficient historical test data is available for trending purposes.

A motor diagnostic system that uses Fourier analysis of the motor current waveform has been developed to detect defects in the motor or driven equipment. This is based on the principle that an electric motor acts as a transducer. For example, when broken rotor bars are present, harmonic fluxes are produced in the air gap, which then induce harmonic components in the motor current waveform. The motor current waveform can be readily converted from a time domain to a frequency domain using Fast Fourier analysis, and the amplitude of each of the component frequencies can be evaluated to determine problems in both the motor and the driven equipment. Past problems with MOV motors have been demonstrated in testing the motor by performance of, for example, a stroke time test at zero differential pressure: motors have been known to stroke the MOV within acceptable stroke time tolerance even with an end ring of the rotor completely melted off. While a visual examination of the rotor is useful for such evidence as cracks, corrosion products, and discoloration, there are potential problems with relying on visual examination of MOVs. When the MOV is in a high radiation field, visual examination is not an appropriate examination method. Current waveform analysis, however, can be performed remotely, with the date being recorded at a computer in a convenient location.

Appendix 7C

Generic Letter 89-10 - Safety-Related[a] Motor-Operated Valve Testing

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D, C. 20555

June 28, 1989

TO: ALL LICENSEES OF OPERATING NUCLEAR POWER PLANTS AND HOLDERS OF CONSTRUCTION PERMITS FOR NUCLEAR POWER PLANTS

SUBJECT: SAFETY-RELATED MOTOR-OPERATED VALVE TESTING AND (GENERIC LETTER NO. 89-10) - 10 CFR 50.54(f)

BACKGROUND

In Bulletin 85-03, dated November 15, 1985, and Supplement 1 of Bulletin 85-03, dated April 27, 1988, the NRC recommended that licensees develop and implement a program to ensure that valve motor-operator switch settings (torque, torque bypass, position limit, overload) for motor-operated valves (MOVs) in several specified systems are selected, set, and maintained so that the MOVs will operate under design-basis[b] conditions for the life of the plant. NRC staff assessments of the reliability of all safety-related MOVs, based on extrapolations of the currently available results of valve surveillance performed in response to Bulletin 85-03, indicate that the program to verify switch settings should be extended in order to ensure operability of all safety-related fluid systems. The NRC staff's evaluation of the data indicates that, unless additional measures are taken, failure of safety-related MOVs and position changeable MOVs (as defined under "Recommended Actions" of this generic letter) to operate under design-basis conditions will occur much more often than had previously been estimated.

(a) The term "safety-related" refers to those systems and components that are relied on to remain functional during and following design-basis events to ensure (i) the integrity of the reactor coolant pressure boundary, (ii) the capability to shut down the reactor and maintain it in a safe shutdown condition, and (iii) the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to the guidelines of 10 CFR Part 100.

(b) Design-basis events are defined as conditions of normal operation, including anticipated operational occurrences design-basis accidents, external events and natural phenomena for which the plant must be designed to ensure the functions delineated in Footnote 1. The design bases for each plant are those documented in pertinent licensee submittals such as the final safety analysis report.

The ASME Code Section XI stroke-timing test for MOVs is performed to meet the inservice testing requirements of 10 CFR 50.55a(g). Section XI testing for MOVs consists of stroking Class 1, 2, and 3 valves open and closed, usually without fluid pressure or flow in the lines, and measuring stroke time. This Section XI testing is a useful tool and complements other tests used to verify MOV operability. Variations in measured stroke times can be significant for DC-powered MOVs and can indicate valve degradation. Additionally, periodic stroking of MOVs provides valve exercise and some measure of on-demand reliability.

Section XI requires corrective action if a MOV does not exhibit its required change of disk position. However, it is now recognized that the Section XI testing alone is not sufficient to provide assurance of MOV operability under design-basis conditions. Assurance of design-basis operability is necessary in order to meet the requirements in General Design Criteria 1, 4, 18, and 21 of Appendix A to 10 CFR Part 50 and Criterion XI of Appendix B to 10 CFR Part 50.

The design basis for certain normally open primary system MOVs (for example, those serving the reactor water cleanup system and the steam supply to high pressure coolant injection and reactor core isolation cooling system turbines in boiling water reactors) demands that these MOVs close to isolate the largest postulated downstream pipe break outside the containment. These MOVs are the subject of a full-scale blowdown flow testing program being conducted by Idaho National Engineering Laboratory (INEL) under NRC sponsorship as part of the resolution of Generic Issue 87 "Failure of HP Steam Line Without Isolation". Preliminary test results[a] indicate that some MOVs nay be subjected to mechanisms and loads that were not accounted for previously. INEL's preliminary conclusions indicate that industry sizing equations for MOVs that must perform this type of safety-related function may not be conservative for all design-basis conditions. The purpose of these tests is to confirm that these valves will operate under design-basis conditions and, if possible, to identify the causes of any failures. The design, testing, and maintenance of all valves and assuring of their operability are the responsibility of the licensees.

INEL has concluded that diagnostic systems that measure both-stem thrust and motor torque are best suited for predicting valve motor performance under design-basis conditions. However, on the basis of INEL's preliminary conclusions, it is not clear that tests of an MOV at low or moderate pressure differentials can be directly extrapolated to determine correct switch settings at design-basis conditions using any type of diagnostic techniques, even for single-phase liquid flow. Currently, the most accurate method of determining switch settings and overall competence of the MOV is to perform testing at or near design-basis conditions, either in situ or on prototype valves.

However, demonstrating operability in situ at design-basis conditions is not practical for some MOVs. Alternatives to testing at design-basis conditions that industry has used include testing at low differential pressure or low flow, as appropriate, combined with MOV surveillance using suitable signature analysis diagnostic techniques. Licensees should ensure that any tests conducted using diagnostic techniques, along with in situ tests conducted at conditions less severe than design-basis conditions, will be applied appropriately to ensure design-basis operability of safety-related MOVs.

(a) On February 1, 1989, in Rockville, Maryland, results of the INEL tests were described in an NRC sponsored public meeting to review valve blowdown tests. A transcript of the meeting is available from Heritage Reporting Corporation, 1220 L Street, N.W., Suite 600, Washington, D.C. 20005.

Licensees should also be aware that increasing MOV thrust by increasing torque switch settings, in order to satisfy design-basis operability considerations, may subject the valve subcomponents to increased forces when the valve is operated at no-load or low-load conditions. Such conditions should be evaluated by the licensee to ensure that MOV operability is not compromised. The NRC will provide additional information on MOV performance under full scale blowdown test conditions as it becomes available. Licensees are specifically cautioned, however, that the INEL tests are not directed toward determining the capability and limitations of various MOV diagnostic systems. Therefore, licensees are also encouraged to consider the need for industry sponsored MOV test programs to ensure that diagnostic techniques can be used to determine the correct adjustments to ensure operability of those safety-related MOVs for which testing at design basis conditions cannot practically be performed in situ.

Assurance of MOV operability is a complex task. It involves many factors such as development of strong testing and maintenance programs, management support and coordination of engineering, maintenance, and testing. This effort should be viewed by all concerned as a long-term ongoing program. Licensees that have already implemented extensive programs on MOVs have found it very beneficial and cost-effective to require that all maintenance and adjustments on the MOV be performed by technicians who have received specific training.

Surveillance, adjustment, maintenance, and repair of safety-related MOVs should be performed in accordance with quality assurance program methods that meet the requirements of 10 CFR Part 50. The recommended actions given in the following section are intended to be consistent with NRC's maintenance policy statement as published in the Federal Register on March 23, 1988 (53 FR 9430). The nuclear power industry has undertaken several generic activities in the area of MOV maintenance and testing. For example, the Electric Power Research Institute has published a maintenance guide and intends to publish an applications guide for MOVs. The results of these efforts may be useful to the industry in developing an effective program.

This letter is part of the resolution of Generic Issue II.E.6.1, "In Situ Testing of Valves," that relates to MOV testing.

RECOMMENDED ACTIONS

By this letter NRC extends the scope of the program outlined in Bulletin 85-0 and Supplement 1 of Bulletin 85-03 to include all safety-related MOVs as well as all position-changeable MOVs as defined below The licensee's program should provide for the testing, inspection, and maintenance of MOVs so as to provide the necessary assurance that they will function when subjected to the design basis conditions that are to be considered during both normal operation and abnormal events within the design basis of the plant although this program should address safety-related MOVs and position-changeable MOVs as a minimum, NRC envisions that, as part of a good maintenance program, other MOVs in the balance of plant should be considered for inclusion in the program, commensurate with the licensee's assessment of their importance to safety.

Any MOV in a safety-related system that is not blocked from inadvertent operation from either the control room, the motor control center, or the valve itself should be considered capable of being mispositioned (referred to as position-changeable MOVs) and should be included in the program. When determining the maximum differential pressure or flow for position-changeable MOVs, the fact that the MOV must be able to recover from mispositioning should be considered. The program to respond to this letter should address items a through h below. Items a, b, and c, and the first paragraph of d are repeated, with limited changes, from Bulletin 85-03 or from Supplement 1 of that bulletin. The second paragraph of item d, and items e, f, g, and h, provide additional clarification and guidance.

a. Review and document the design basis for the operation of each MOV. This documentation should include the maximum differential pressure expected during both the opening and closing of the MOV for both normal operations and abnormal events, to the extent that these MOV operations any events are included in the existing approved design basis.

b. Using the results from item a, establish the correct switch settings. This should include establishing a program to review and revise, as necessary the methods for selecting and setting all switches (i.e., torque, torque bypass, position limit, overload) for each valve operation (opening and closing). One purpose of this letter is to ensure that a program exists for selecting and setting valve operator switches to ensure high reliability of safety-related MOVs.

c. Individual MOV switch settings should be changed, as appropriate, to those established in response to item b. Whether the switch settings are changed or not, the MOV should be demonstrated to be operable by testing it at the design-basis differential pressure or flow determined in response to item a. Testing MOVs at design-basis conditions is not recommended where such testing is precluded by the existing plant configuration. An explanation should be documented for any cases where testing with the design-basis differential pressure or flow cannot practicably be performed. This explanation should include a description of the alternatives to design-basis differential pressure testing or flow testing that will be used to verify the correct settings.

   Note: This letter is not intended to establish a recommendation for valve testing for the condition simulating a break in the line containing the MOV. However, a break in the line should be considered in the analyses described in items a, b, and c, if MOV operation is relied on in the design basis.

   Each MOV should be stroke tested, to verify that the MOV is operable at no-pressure or no-flow conditions even if testing with differential pressure or flow cannot be performed.

d. Prepare or revise procedures to ensure that correct switch settings are determined and maintained throughout the life of the plant. These procedures should include provisions to monitor MOV performance to ensure the switch settings are correct. This is particularly important if the torque or torque bypass switch setting has been significantly raised above that required.

   It may become necessary to adjust MOV switch settings because of the effects of wear or aging. Therefore, it is insufficient to merely verify that the switch settings are unchanged from previously established values. The switch settings should be verified in accordance with the program schedule (see item j). The ASME Code Section XI stroke-timing test required by 10 CFR Part 50 is not oriented toward verification of switch setting. Therefore, additional measures should be taken to adequately verify that the switch settings ensure MOV operability. The switch settings need not be verified each time the ASME Code stroke-timing test is performed.

e. Regarding item a, no change to the existing plant design basis is intend and none should be inferred. The design-basis review should not be restricted to a determination of estimated maximum design-basis differential pressure, but should include an examination of the pertinent design and installation criteria that were used in choosing the particular MOV. For example, the review should include the effects on MOV performance of design-basis degraded voltage, including the capability of the MOV's power supply and cables to provide the high initial current needed for the operation of the MOV.

f. Documentation of explanations and the description of actual test methods used for accomplishing item c should be retained as part of the required records for the MOV.

It is also recognized that it may be impracticable to perform in situ MOV testing at design-basis degraded voltage conditions. However, the switch settings established in response to item b should at least be established to account for the situation where the valves may be called on to operate at design-basis differential pressure, or flow, and under degraded voltage conditions. If the licensee failed to consider degraded voltage, power supply or cable adequacy for MOVs in systems covered by Bulletin 85-03, the design review and established switch settings for those MOVs should be reevaluated.

Alternatives to testing a particular MOV in situ at design-basis pressure or flow, where such testing cannot practicably be performed, could include a comparison with appropriate design-basis test results on other MOVs either in situ or prototype. If such test information is not available, analytical methods and extrapolations to design-basis conditions, based on the best data available, may be used until test data at design-basis conditions become available to verify operability of the MOV. If this two-stage approach is followed, it should be accomplished within the schedule outlined in item i and would allow for MOV testing and surveillance to proceed without excessive delay.

Testing of MOVs at design-basis conditions need not be repeated unless the MO is replaced, modified, or overhauled to the extent that the licensee consider that the existing test results are not representative of the MOV in its modified configuration.

g. A number of deficiencies, misadjustments, and degraded conditions were discovered by licensees either as a result of their efforts to comply with Bulletin 85-03 or from other experiences. A list of these conditions (including improper switch settings) is included in Attachment A to this letter for licensee review and information.

h. Each MOV failure and corrective action taken, including repair, alteration, analysis, test, and surveillance, should be analyzed or justified and documented. The documentation should include the results and history of each as-found deteriorated condition, malfunction, test, inspection, analysis, repair, or alteration. All documentation should be retained and reported in accordance with plant requirements.

It is suggested that these MOV data be periodically examined (at least every 2 years or after each refueling outage after program implementation) as part of a monitoring and feedback effort to establish trends of MOV operability. These trends could provide the basis for a licensee revision of the testing frequency established to periodically verify the adequacy of MOV switch settings (see items d and j). For this monitoring and feedback effort, a well-structured and component-oriented system (e.g., the Nuclear Plant Reliability Data System [NPRDS]) is needed to capture, track, and share the equipment history data. The NRC encourages the use of the industry-wide NPRDS appropriately modified, for this purpose in view of the multiple uses for these data.

SCHEDULE

The program to respond to this letter should be implemented in accordance wit the schedule outlined in items i through k below. The scheduled dates should ensure that item c is implemented soonest for those MOVs that the licensee considers to have the greatest impact on plant safety.

i. Each licensee with an operating license (OL) should complete all design basis reviews, analyses, verifications, tests, and inspections that have been instituted in order to comply with items a through h within 5 years or three refueling outages of the date of this letter, whichever is later. Each licensee with a construction permit (CP) should complete-these actions within 5 years of the date of this letter or before the OL is issued, whichever is later.

   For plants with an OL, the documentation described in items 1 and 2 below should be available within 1 year or one refueling outage of the date of this letter, whichever is later. For plants with a CP, the documentation outlined in items 1 and 2 should be available within 1 year of the date of this letter or before the OL is issued, whichever is later. The documents should include:

   1. The description and schedule for the design-basis review recommended in item a (including guidance from item e) for all safety-related MOVs and position-changeable MOVs as described, and

   2. The program description and schedule for items b through h for all safety-related MOVs and position-changeable MOVs.

j. The program for the verification of the procedures outlined in item d, as well as other tests or surveillance that the owner may choose to use to identify potential MOV degradations or misadjustments, such as those described in Attachment A, should be implemented after maintenance or adjustment (including packing adjustment) of each MOV and periodically thereafter. The surveillance interval should be based on the licensee's evaluation of the safety importance of each MOV as well as its maintenance and performance history. The surveillance interval should not exceed 5 years or three refueling outages, whichever is longer, unless a longer interval can be justified (see item h) for any particular MOV.

k. In recognition of the necessity for preplanning, refueling outages that start within 6 months of the date of this letter need not be counted in establishing the schedule to meet the time limits recommended in items i and j.

REPORTING REQUIREMENTS

Pursuant to 10 CFR 50.54(f), licensees are required to provide information to NRC as outlined in items 1 and m below:

l. Each licensee shall advise the NRC in writing, within 6 months of the date of this letter, that the above schedule and recommendations will be met. For any date that cannot be met, the licensee shall advise the NRC of a revised schedule and provide a technical justification in writing. For any recommendation that it cannot meet or proposes not to meet, the licensee shall inform the NRC and provide a technical justification, including any proposed alternative action, in writing.

Each licensee shall also submit, in writing, any future changes to scheduled commitments; for example, changes made on the basis of trending results (see items h and j). These revised schedules or alternative actions may be implemented without NRC approval. Justification for the revised schedules and alternative actions should be retained on site.

m. Each licensee shall notify the NRC in writing within 30 days after the actions described in the first paragraph of item i have been completed.

This generic letter supersedes the recommendations in Bulletin 85-03 and its supplement. Bulletin 85-03 addressees need not make any further responses regarding that bulletin or its supplement. The information that was or would have been submitted to the NRC in response to Bulletin 85-03 or its supplement should be retained in accordance with the recommendations of this generic letter.

Documented results of tests or other surveillance that were used to satisfy the recommended actions of Bulletin 85-03 or the supplement to that bulletin or a voluntary extension of the recommendations in those documents to other MOVs may be used, to the extent applicable, to satisfy the recommendations stated herein.

This request is covered by Office of Management and Budget Clearance Number 3150-0011, which expires December 31, 1989. The estimated average burden hours are 2000 person-hours per licensee response including assessing the new recommendations, searching data sources, gathering and analyzing the data, and preparing the required letters. These estimated average burden hours pertain only to the identified response-related matters and do not include the time for the actual implementation of the requested actions. Comments on the accuracy of this estimate and suggestions to reduce the burden may be directed to the Office of Management and Budget, Paperwork Reduction Project (3150 0011), Washington D.C. 20503, and the U.S. Nuclear Regulatory Commission, Records and Reports Management Branch, Office of Information Resources Management, Washington, D.C. 20555.

If you have any questions regarding this matter, please contact the NRC Lead Project Manager Thierry Ross at (301) 492-3016 or the technical contact listed below.

James G. Partlow

Associate Director for Projects
Office of Nuclear Reactor Regulation

Enclosure: Listing of Recently Issued Generic Letters and Attachment A

Technical Contact: T. Marsh, NRR/EMEB (301) 492-0902

Attachment A of Generic Letter 89-10

Summary of Common Motor-Operated Valve Deficiencies, Misadjustments, and Degraded Conditions

1. Incorrect torque switch bypass settings
2. Incorrect torque switch settings
3. Unbalanced torque switch
4. Spring pack gap or incorrect spring pack preload
5. Incorrect stem packing tightness
6. Excessive inertia
7. Loose or tight stem-nut locknut
8. Incorrect limit switch settings
9. Stem wear
10. Bent or broken stem
11. Worn or broken gears
12. Grease problems (hardening, migration into spring pack, lack of grease, excessive grease, contamination, non-specified grease)
13. Motor insulation or rotor degradation
14. Incorrect wire size or degraded wiring
15. Disk or seat binding (includes thermal binding)
16. Water in internal parts or deterioration therefrom
17. Motor undersized (for degraded voltage conditions or other conditions)
18. Incorrect valve position indication
19. Misadjustment or failure of handwheel declutch mechanism
20. Relay problems (incorrect relays, dirt in relays, deteriorated relays, miswired relays)
21. Incorrect thermal overload switch settings
22. Worn or broken bearings
23. Broken or cracked limit switch and torque switch subcomponents
24. Missing or modified torque switch limiter plate
25. Improperly sized actuators
26. Hydraulic lockup
27. Incorrect metallic materials for gears, keys, bolts, shafts, etc.
28. Degraded voltage (within design basis)
29. Defective motor control logic
30. Excessive seating or backseating force application
31. Incorrect reassembly or adjustment after maintenance or testing
32. Unauthorized modifications or adjustments
33. Torque switch or limit switch binding.

8.0 Reactor Protection System

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

Because of its important contribution to plant safety, the RPS is designed, constructed, and tested to meet the highest standards. The system must be able to supply reactor and component trip signals and initiate engineered safety features to provide the required degree of protection for all normal operating and accident conditions. A simplified block diagram of the RPS is shown in Figure 8.1; a typical sensor channel is shown in Figure 8.2. The nuclear and process instrument subsystems send trip signals to the logic trains. There are two complete and independent sets of logic circuits in the RPS cabinets, as shown in Figure 8.3; each set constitutes a logic train. When an unsafe condition is sensed, a signal is sent to the RPS cabinets. If a reactor trip is required, the RPS logic sends a signal to open the reactor trip breakers. Tripping these breakers removes power from the control rod drive mechanisms for Pressurized-Water Reactors, allowing the rods to drop into the reactor core, thus shutting down the reactor. If an engineered safety feature actuation is required, the RPS logic actuates the appropriate safety equipment, depending on plant conditions. Permissive signals are also provided by the logic trains to allow automatic or manually initiated interlocks and bypasses.

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

Nuclear Plant Aging Research (NPAR) studies of the RPS were conducted by Idaho National Engineering Laboratory (Meyer 1988; Sharma 1992), Oak Ridge National Laboratory (Gehl et al. 1992), and Wyle Laboratories (Gleason 1992). These studies provided the technical basis for the RPS standard technical specifications (STS) aging evaluation. Additional information was obtained from publications by Blahnik et al. (1992), Edson (1992), Gleason (1991a, 1991b), Hashemian (1991), Husler and Weir (1991), IEEE Standard 1205-1993, Meyer and Edson (1990), and Shah (1987).

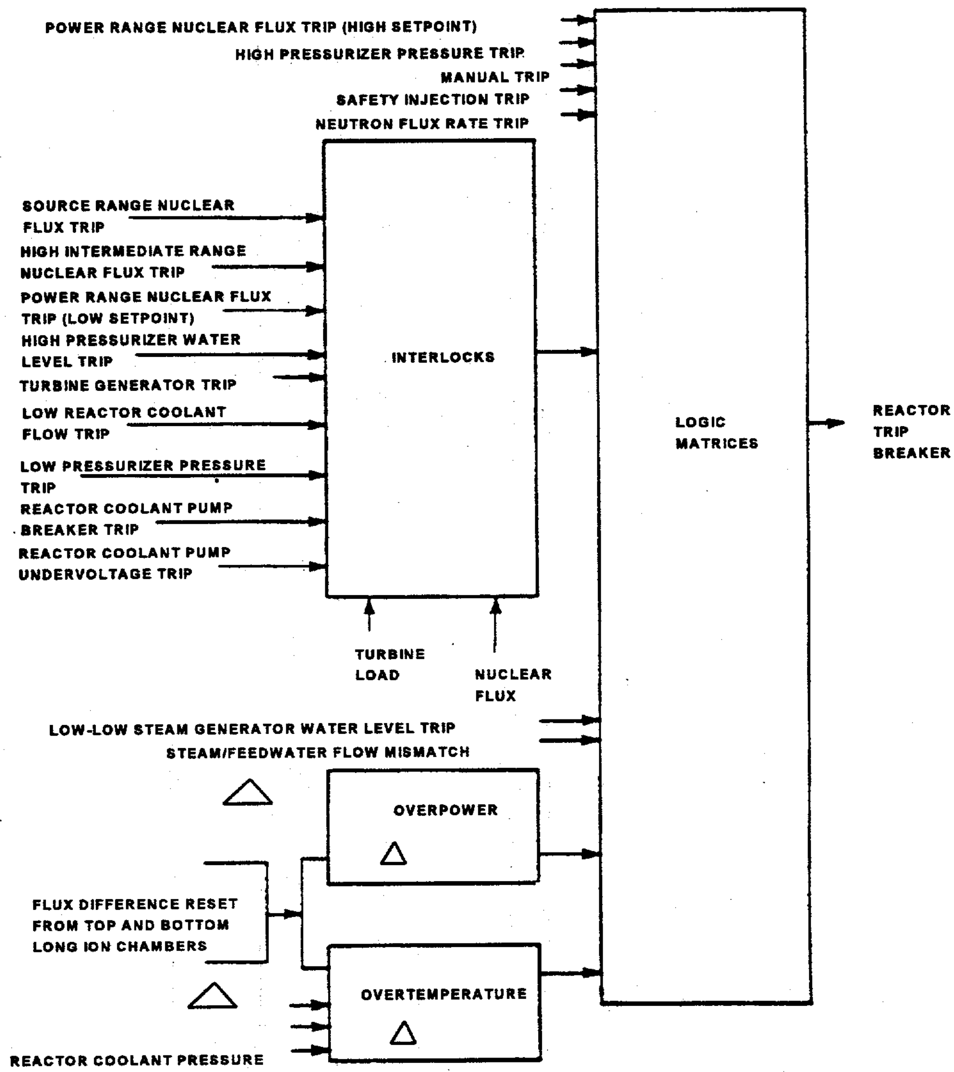

Figure 8.1. Simplified Reactor Protection System Block Diagram

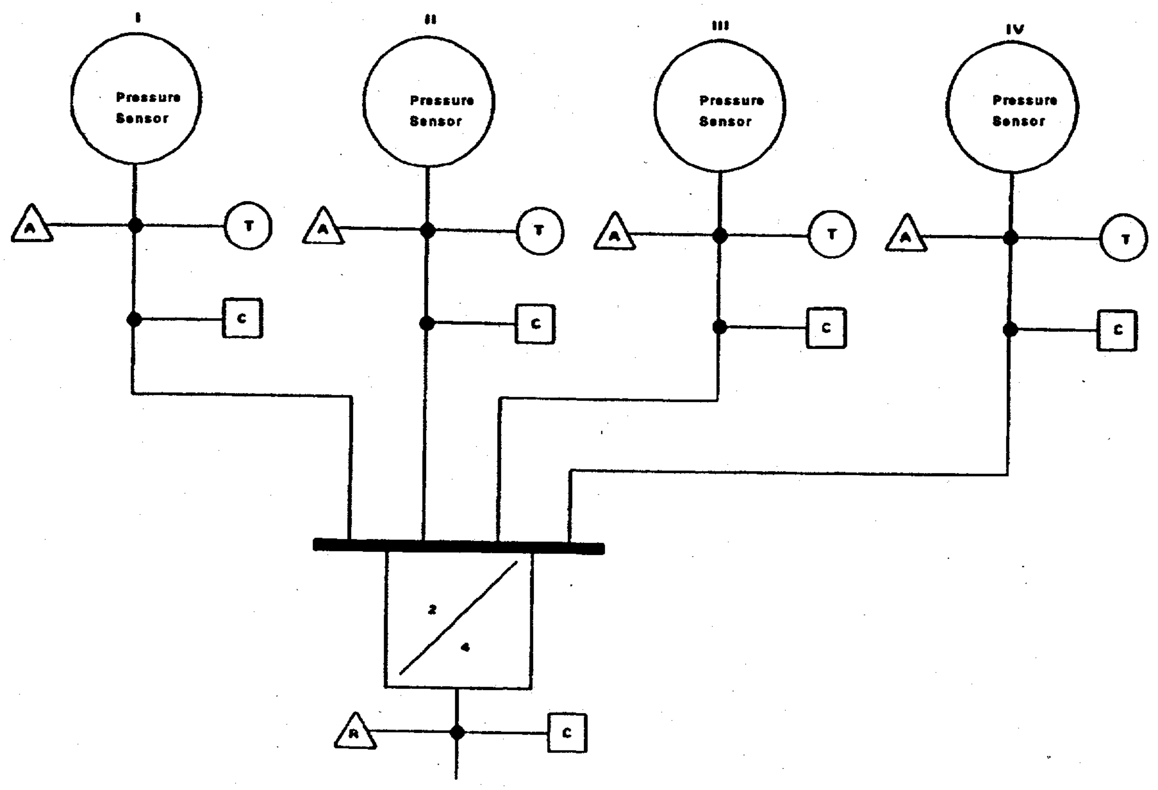

Figure 8.2. Typical Reactor Protection System Sensor Channel (pressure)

8.1 Reactor Protection System Description and Boundaries

The basic philosophy of the RPS is to define an operating envelope for a nuclear power plant, then to safely shut down the plant when the limits of this envelope are reached or exceeded. The process of monitoring plant conditions and acting on them is accomplished by using various sensing devices, processing circuits, logic circuits, and control and actuation circuits. The RPS also functions to actuate emergency equipment in the event of a loss of primary or secondary coolant inventory.

The RPS is composed of the sensors, cables, signal-conditioning devices, logic circuits, and actuation relay circuits required to initiate a reactor shutdown and to actuate emergency equipment. A simplified RPS block diagram for a typical nuclear power plant is shown in Figure 8.1, where the raw parameter information from the various sensing devices is sent through various computation, amplification, and conditioning circuits to the indicators, alarms, and actuators. The logic circuits are used to decide whether the operating envelope has been reached. These logic circuits take the processed signals and compare them to preset setpoints. If the input signal exceeds the setpoint, then the actuation relay circuits are activated. These circuits control the various alarms and the reactor trip breaker. If the trip breakers are actuated, the reactor is shut down.

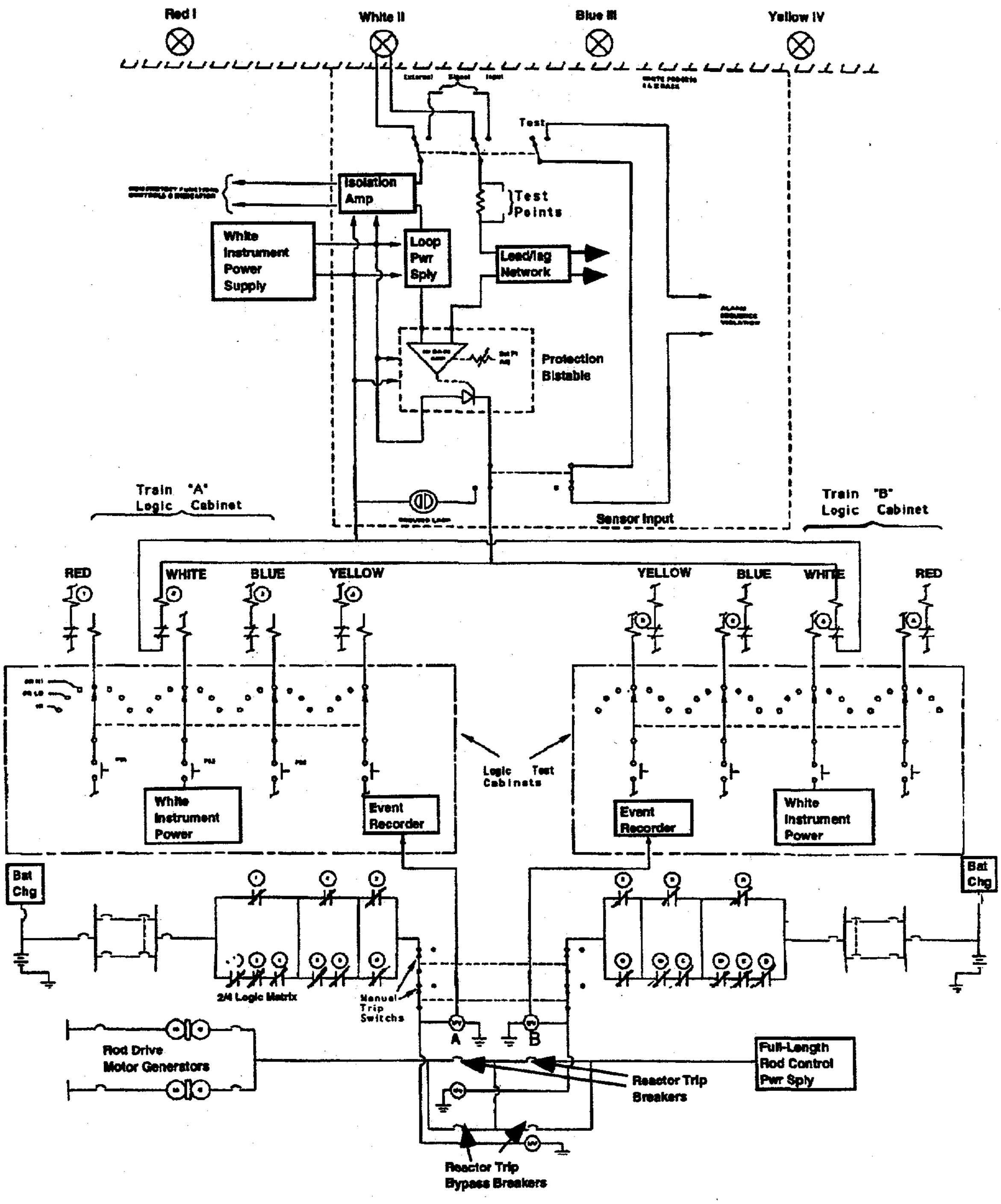

Figure 8.3. Typical Reactor Protection System Channel Logic Circuit

An example of a typical sensor channel is shown in Figure 8.2; the logic matrices and reactor trip breakers are shown in Figure 8.3. These figures are general in nature, as specific designs vary greatly from plant to plant and between types of reactors. A sensor is a device that measures directly a process variable, then produces an output signal or indication proportional to the measured variable. Sensors for pressure, flow, and level measurements are primarily pressure or differential pressure transmitters. Temperature sensors are usually resistance temperature detectors. Reactor power is using a neutron measurement device, such as compensated ion chambers. Other sensors include limit switches or contacts to detect position, current transformers to measure current, thermocouples, strain gauges, resonant wires, piezoelectric devices, variable reluctance devices, capacitive elements, Bourdon tubes, and linear variable differential transformers.

Process electronics include instrument power supplies, buffer amplifiers, signal amplifiers, conditioners, and computation modules. Process logic circuits contain bistables and comparators used to determine whether the process operating envelope has been reached. The actuation relay circuit consists of relays connected in various matrices to provide the reactor trip or emergency equipment actuation logic. Some nuclear power plants use solid-state (digital) techniques that reduce the number of relays and cabinets.

8.2 Stressors, Aging Mechanisms, and Aging Effects

To facilitate this aging evaluation, the RPS components were divided into the following smaller, more manageable modules:

- switches
- detectors/sensors
- power supplies, amplifiers, converters, conditioners
- wiring/junction boxes
- logic circuits (that is, bistables, comparators)
- actuation relay circuits
- breaker hardware
- breaker relays and control circuits.

Known RPS stressors and the resulting aging mechanisms and aging effects for each of the RPS modules are summarized in Table 8.1. Examples of stressors that influence the operation of the RPS include heat, moisture or humidity, foreign material contamination, and operation. The effects of these stressors may ultimately lead to corrosion of electrical connections and mechanical linkages, calibration drift, and circuit failure. Adverse effects from aging become apparent over time, and more than one

Table 8.1. Summary of Detection Capability of Current SRs

RPS Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Methods	Addressed by STS SRs?[a]
switches	contaminants	abrasion/galling	binding/lockup sticking open/ shut	operational testing	3.3.1.13, 3.3.1.14, 3.3.2.5, 3.3.2.7, 3.3.2.8, 3.3.2.11
				multiple signal analyses	no
				infrared thermography	no
				visual inspection	no
		arcing	melting/decrease in electrical resistance	voltage/resistance test	no
				visual inspection	no
				multiple signal analyses	no
				infrared thermography	no
	operation	wear	binding/loosening	operational testing	3.3.1.13, 3.3.1.14, 3.3.2.5, 3.3.2.7, 3.3.2.8, 3.3.2.11
				multiple signal analyses	no
				infrared thermography	no
				visual inspection	no
detectors/sensors	contaminants	arcing	melting/decrease in electrical resistance	calibration test	3.3.1.1, 3.3.1.6, 3.3.1.10, 3.3.1.11, 3.3.1.12, 3.3.2.1, 3.3.2.9
				voltage/resistance test	no
				infrared thermography	no
				redundant instrumentation monitoring	no
				multiple signal analyses	no
				visual inspection	no

(a) Representative SRs are listed where applicable.

Table 8.1. (contd)

RPS Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Methods	Addressed by STS SRs?[a]
detectors/sensors (contd)		corrosion	increase in electrical resistance	calibration test	3.3.1.1, 3.3.1.6, 3.3.1.10, 3.3.1.11, 3.3.1.12, 3.3.2.1, 3.3.2.9
				voltage/resistance test	no
				infrared thermography	no
				redundant instrumentation monitoring	no
				multiple signal analyses	no
			increase in electrical resistance	visual inspection	no
	heat	overheating	output drift	calibration test	3.3.1.1, 3.3.1.6, 3.3.1.10, 3.3.1.11, 3.3.1.12, 3.3.2.1, 3.3.2.9
				voltage/resistance test	no
				infrared thermography	no
				multiple signal analyses	no
				redundant instrumentation monitoring	no
				time response test	3.3.1.16, 3.3.2.10
power supplies, convertors, conditioners, amplifiers, computation modules	contaminants	arcing	melting/decrease in electrical resistance	calibration test	3.3.1.1, 3.3.1.6, 3.3.1.10, 3.3.1.11, 3.3.1.12, 3.3.2.1, 3.3.2.9
				voltage/resistance test	no
				infrared thermography	no
				redundant instrumentation monitoring	no

(a) Representative SRs are listed where applicable.

Table 8.1. (contd)

RPS Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Methods	Addressed by STS SRs?[a]
power supplies, convertors, conditioners, amplifiers, computation modules (contd)				multiple signal analyses	no
				visual inspection	no
		corrosion	increase in electrical resistance	calibration test	3.3.1.1, 3.3.1.6, 3.3.1.10, 3.3.1.11, 3.3.1.12, 3.3.2.1, 3.3.2.9
				voltage/resistance test	no
				infrared thermography	no
				redundant instrumentation monitoring	no
				multiple signal analyses	no
				visual inspection	no
	ohmic heating	differential thermal expansion	increase in electrical resistance	calibration test	3.3.1.1, 3.3.1.6, 3.3.1.10, 3.3.1.11, 3.3.1.12, 3.3.2.1, 3.3.2.9
				voltage/resistance testing	no
				infrared thermography	no
				redundant instrumentation monitoring	no
				multiple signal analyses	no
wiring\junction boxes	heat	embrittlement	loss of dielectric strength	resistance testing	no
				multiple signal analyses	no
				infrared thermography	no
	humidity	oxidation	increase in electrical resistance	resistance testing	no
				multiple signal analyses	no
				infrared thermography	no

(a) Representative SRs are listed where applicable.

Table 8.1. (contd)

RPS Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Methods	Addressed by STS SRs?[(a)]
wiring/junction boxes (contd)	contaminants	arcing	decrease in electrical resistance/loss of dielectric strength	resistance/voltage testing	no
				multiple signal analyses	no
				infrared thermography	no
actuation relay circuit	operation	wear	binding/loosening	operational test, time response test	3.3.1.5, 3.3.1.7, 3.3.1.8, 3.3.1.9, 3.3.1.13, 3.3.1.14, 3.3.1.15, 3.3.2.2, 3.3.2.3, 3.3.2.4, 3.3.2.5, 3.3.2.6, 3.3.2.7, 3.3.2.8, 3.3.2.11
		fatigue	cracking/fracture	analysis/visual inspection	no
				voltage/resistance testing	no
				infrared thermography	no
				multiple signal analyses	no
				redundant instrumentation monitoring	no
				operational test, time response test	3.3.1.5, 3.3.1.7, 3.3.1.8, 3.3.1.9, 3.3.1.13, 3.3.1.14, 3.3.1.15, 3.3.2.2, 3.3.2.3, 3.3.2.4, 3.3.2.5, 3.3.2.6, 3.3.2.7, 3.3.2.8, 3.3.2.11

(a) Representative SRs are listed where applicable.

Table 8.1. (contd)

RPS Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Methods	Addressed by STS SRs?[a]
actuation relay circuit (contd)		pitting	increase in electrical resistance	voltage/resistance testing	no
				infrared thermography	no
				multiple signal analyses	no
				redundant instrumentation monitoring	no
		arcing	melting/sticking closed	operational testing	3.3.1.5, 3.3.1.7, 3.3.1.8, 3.3.1.9, 3.3.1.13, 3.3.1.14, 3.3.1.16, 3.3.2.2, 3.3.2.3, 3.3.2.4, 3.3.2.5, 3.3.2.6, 3.3.2.7, 3.3.2.8, 3.3.2.10, 3.3.2.11
				voltage/resistance testing	no
				infrared thermography	no
				multiple signal analyses	no
				redundant instrumentation monitoring	no
	contaminants	abrasion/galling	binding/lockup sticking open/shut	operational testing	3.3.1.5, 3.3.1.7, 3.3.1.8, 3.3.1.9, 3.3.1.14, 3.3.1.16, 3.3.2.2, 3.3.2.3, 3.3.2.4, 3.3.2.5, 3.3.2.6, 3.3.2.7, 3.3.2.8, 3.3.2.10, 3.3.2.11

(a) Representative SRs are listed where applicable.

Table 8.1. (contd)

RPS Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Methods	Addressed by STS SRs?[(a)]
actuation relay circuit (contd)				infrared thermography	no
				multiple signal analyses	no
				visual inspection	no
		arcing	melting/decrease in electrical resistance	voltage/resistance test	no
				redundant instrumentation monitoring	no
				infrared thermography	no
				multiple signal analyses	no
				visual inspection	no
	humidity	oxidation	increase in electrical resistance	voltage/resistance test	no
				infrared thermography	no
				multiple signal analyses	no
				redundant instrumentation monitoring	no
logic circuits, bistables, comparators	contaminants	corrosion		voltage/resistance test	no
				infrared thermography	no
				multiple signal analyses	no
				redundant instrumentation monitoring	no
	humidity	oxidation	increase in electrical resistance	voltage/resistance test	no
				infrared thermography	no
				multiple signal analyses	no
				redundant instrumentation monitoring	no

(a) Representative SRs are listed where applicable.

Table 8.1. (contd)

RPS Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Methods	Addressed by STS SRs?[a]
breaker hardware	contaminants	abrasion/galling	binding/lockup of operating mechanisms	operational testing .	3.3.1.4
				infrared thermography	no
				multiple signal analyses	no
				visual inspection	no
	operation	wear	loosening operating mechanisms	operational testing	3.3.1.4
				infrared thermography	no
				multiple signal analyses	no
				time response test	no
				visual inspection	no
		fatigue	loss of mechanical strength	analysis	no
breaker relays and control circuits	operation	wear	binding/loosening	trip timing test	3.3.1.4
				infrared thermography	no
				multiple signal analyses	no
				visual inspection	no
		fatigue	cracking/fracture	analysis	no
				infrared thermography	no
				multiple signal analyses	no
				visual inspection	no
		pitting	increase in electrical resistance	voltage/resistance testing	no
				infrared thermography	no
				multiple signal analyses	no
		arcing	melting/sticking closed	operational testing	3.3.1.4
				voltage/resistance testing	no
				infrared thermography	no
				multiple signal analyses	no

(a) Representative SRs are listed where applicable.

Table 8.1. (contd)

RPS Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Methods	Addressed by STS SRs?[a]
breaker relays and control circuits (contd)	contaminants	abrasion/galling	binding/lockup sticking open/shut	operational testing	3.3.1.4
				infrared thermography	no
				multiple signal analyses	no
				visual inspection	no
		arcing	melting/decrease in electrical resistance	voltage/resistance test	no
				infrared thermography	no
			melting/decrease in electrical resistance	multiple signal analyses	no
				visual inspection	no
	humidity	oxidation	increase in electrical resistance	voltage/resistance test.	no
				infrared thermography	no
				multiple signal analyses	no

(a) Representative SRs are listed where applicable.

stressor can be responsible for the same ultimate aging degradation. Inadequate or improper maintenance of the RPS can also contribute to premature degradation. The overall impacts of these degradation mechanisms are plant-specific.

Also noted in Table 8.1 is whether or not a particular aging degradation effect is detected by the current Westinghouse plant surveillance requirements (SRs). The SRs are listed by number and the text of the SR is summarized in Appendix 8A. Appendices 8B and 8C list the reactor trip functions and engineered safety feature actuation functions, respectively, and their applicable SRs.

A potential deficiency in the SRs is identified when a particular aging effect is not detected by any existing SR (i.e., the component might experience undetected degradation). A list of recommended SRs to address the undetected degradation is presented in Section 8.6. Degradation effects that are more appropriately addressed by an effective maintenance program (i.e., swell of potting compound) are not included.

It is appropriate to address the obsolescence of RPS modules in this evaluation. Vendor-supplied replacement parts or repair support for signal conditioning devices are not normally provided beyond a nominal 15- to 20-year period; obsolescence of this module is a significant problem. Electric or electronic parts in nuclear power plants are replaced most often for reasons of technological obsolescence; such replacement is a continual activity at nuclear power plants. Further, some RPS components are routinely examined and refurbished under existing programs that are effective in mitigating or eliminating concerns due to the effects of aging.

8.3 Degradation Detection Methods

Several methods that are effective in detecting aging degradation of RPS have been developed, either historically or in response to specific aging concerns. The specific detection methods applicable to RPS aging degradation are identified in Table 8.1. While some traditional methods (e.g., calibration and operational testing) are implemented in the current SRs, a much broader assortment of methods is available for detecting RPS aging degradation. For example, a typical method for determining the location of increased circuit resistance would be a simple voltage/resistance test that might use a hand-held ohm meter.

Degradation detection methods that are less intrusive and provide a means of trending aging of an electric RPS component include infrared thermography, redundant instrumentation monitoring, and multiple signal analyses. These methods are useful and appropriate for inclusion in the SRs and are identified in Section 8.6 as recommendations to improve or supplement the SRs. A more detailed discussion of these detection methods is presented in Appendix 8D.

8.4 Evaluation of Existing Surveillance Requirements for Effectiveness in Detecting Aging Degradation

The current SRs (Appendix 8A) specify calibration and test requirements for RPS modules. Extensive RPS testing is required to ensure that failures are discovered as soon as possible to minimize the time during which the nuclear power plant operates with a reduced level of redundancy in the plant protection system. The potential effects of RPS failure are either

- an instrument failure produces a trip signal that, in coincidence with spurious signals on other instrument channels, results in a reactor trip, thus causing an unnecessary loss of plant availability

OR

- an instrument fails to produce a trip signal, thus reducing the redundancy of the protection system and, therefore, the safety of the system.

The STS surveillance requirements are useful to determine the current condition of an RPS module. If testing indicates marginal performance, then corrective action can be taken to prevent failure during operation. However, present SR testing cannot predict the occurrence of a forthcoming module failure or the effects of RPS aging. More importantly, a significant portion of the RPS failures are not being detected by the current SRs. Almost half of the RPS failures are being detected by nonroutine methods, such as operational abnormality, special inspection, audiovisual alarm, incidental observation, and corrective maintenance.

Evaluation of degradation conditions shows that the current SRs do not always detect significant aging degradation; electronic components and circuits tend to fail catastrophically rather than by gradual degradation. Applicable data are acquired on RPS modules, but methodologies are not generally in place for trending of the data. Surveillance requirements are typically based on functionality and pass or fail tolerance measurements of voltage and current; visual examination also plays an important part in these practices. "AS FOUND" and "AS LEFT" measurements are manually acquired and recorded, but long-term comparisons for trending are not performed.

Calibration and testing alone are therefore not sufficient to ensure RPS condition. Existing SRs do not allow adequate condition monitoring to detect and trend aging degradation. Improving current SRs for RPS modules can greatly enhance the reliability of the entire system.

8.5 Evaluation of Existing Surveillance Requirements for Possible Contributions to Premature Aging Degradation

The existing SRs for RPS are designed primarily to determine operability and not to trend aging degradation. This can cause problems when, for example, an undetected degraded relay exists which fails to detect abnormal voltage conditions, thus affecting system and equipment operability and lowering the level of plant safety. Conversely, when STS-required testing is performed too frequently, unnecessary stresses could be placed on some modules, thus causing a situation conducive to module degradation. This too-frequent testing could contribute to module degradation and accelerate aging of the RPS.

8.6 Recommendations to Improve or Supplement Surveillance Requirements

The NPAR studies of the RPS have determined that, in some cases, current SRs do not detect significant age-related degradation, and that in other cases, the parameter change detected can be misleading, overlooking serious age-related degradation. Sensors, electronic parts, and bistables are RPS components that fail most often. Over one third of RPS failures occur during plant operation rather than during maintenance, testing, or examination. Because of the redundancy built into the RPS, loss of system function is extremely rare; more often, the result is loss of a subsystem or channel, leading to a loss of redundancy and degraded system operation. This failure pattern and NPAR research results indicate that current monitoring and testing methods could be improved, leading to an improvement in RPS reliability. Advanced monitoring methods have been developed that could further ensure RPS reliability. These improved surveillance methods are more effective at detecting aging degradation than are the current practices at nuclear power plants. These improved methods are state-of-the-art infrared thermography data acquisition and analysis, redundant instrumentation monitoring, and multiple signal analyses.

8.6.1 Recommendations from the NPAR Aging Assessments

The NPAR studies of the RPS have developed additional recommendations that address age-related issues. Not every degradation detection method that is identified in Table 8.1 is appropriate for inclusion in the SRs. For example, visual examination of RPS modules can be very effective in detecting age-related degradation, but it is a method that is better suited for inclusion in a maintenance program than in the STS. The following recommendations address aging issues in the SRs, making them more effective in detecting, trending, and monitoring degradation of the RPS before failure. These recommendations are suggested for incorporation into SRs for risk significant and prioritized RPS modules:

1. Representative samples of risk-significant and prioritized RPS modules should be examined by a multiple signal analyses process, as described in Appendix 8D, once every week for evidence of aging degradation, such as an increase in electrical resistance.

2. Representative samples of risk-significant and prioritized RPS modules should be examined by a redundant instrumentation monitoring process once every week for evidence of aging degradation, such as calibration drift.

3. Representative samples of risk-significant and prioritized RPS modules should be tested for response time on *an increased frequency* (at least once every month) for evidence of aging degradation resulting in an increase in response time.

4. Representative samples of risk-significant and prioritized RPS modules should be examined by infrared thermography performed once every refueling cycle for modules that are not accessible during plant operation, and once every month for accessible modules for evidence of aging degradation, such as overheating.

All surveillance results should be trended over time to note aging effects on the RPS and to identify potential RPS degradation. Additionally, in selecting the above-recommended representative samples, one of two valid sample selection options can be implemented. The first option is to select the sample for each calibration/test and to perform the initial and all subsequent calibration/tests on that sample; this option would facilitate trending of age-related degradation, which could then be extrapolated to the remaining RPS channels. Remaining RPS channels would be calibrated/tested only when deemed necessary, based on trending data. The second sample selection option is to rotate the sample through the RPS channels for subsequent calibration/tests; this option would expand coverage for a better understanding of plant-wide RPS conditions.

8.6.2 Implementing Suggested Recommendations

A list of suggested SRs with associated surveillance frequencies to implement the recommendations from the NPAR RPS aging assessments is provided in Table 8.2. These recommended SRs address the potential for undetected RPS module degradation that was identified in Table 8.1, except for those effects with a very low probability of failure of the module or those that are more appropriately addressed by an effective maintenance program.

An SR is not specified in Table 8.2 for each individual RPS module; rather, the individual degradation detection methods that apply to a particular degradation effect on a module are grouped to form a generically stated SR. Each of these generic SRs would then be expanded by writing them for RPS modules throughout the STS in a form consistent with that of existing SRs, as identified in Appendix 8A.

Table 8.2. Surveillance Requirement Recommendations to Detect and Trend RPS Aging Degradation

Surveillance Requirement[a]	Frequency of Action
Trend parameters (e.g., by means of a multiple signal analyses process) that demonstrate the operability and reliability of RPS modules will not be affected by the following degradation effects: • binding • cracking • fracture • sticking • increase in electrical resistance • decrease in electrical resistance • loosening	7 days
Trend parameters (e.g., by means of infrared thermography) that demonstrate the operability and reliability of accessible RPS modules will not be affected by the following degradation effects: • binding • cracking • fracture • loosening • melting • loss of dielectric strength • output drift • overheating • increase in electrical resistance • sticking	30 days (every refueling cycle for RPS modules not accessible during plant operation)
Trend parameters (e.g., by means of response time testing) that demonstrate the operability and reliability of RPS modules will not be affected by the following degradation effects: • fracture • output drift • loosening	30 days
Trend parameters (e.g., by means of a redundant instrumentation monitoring process) that demonstrate the operability and reliability of RPS modules will not be affected by the following degradation effects: • cracking • melting • output drift • loosening • sticking • increase in electrical resistance	7 days

(a) These SRs should be applied to a representative sample of risk-significant and prioritized RPS modules. In the event that degradation or failure is detected, additional modules should be examined.

Appendix 8A

Summary of Reactor Protection System Surveillance Requirements from Westinghouse STS

SR Number	Surveillance Requirement	Frequency	Detects Aging Degradation?
	Reactor Trip System Instrumentation		
3.3.1.1	Perform Channel Check.	12 hours	no
3.3.1.2	NOTES: 1. Adjust Nuclear Instrumentation System channel if absolute difference is > 2%. 2. not required to be performed until [12] hours after Thermal Power is ≥ 15% rated thermal power. Compare results of calorimetric heat balance calculation to Nuclear Instrumentation System channel output.	24 hours	no
3.3.1.3	NOTES: 1. Adjust Nuclear Instrumentation System channel if absolute difference is ≥ 3%. 2. not required to be performed until [24] hours after Thermal Power is ≥ [15%] Reactor Protection System. Compare results of the incore detector measurements to Nuclear Instrumentation System Axial Flux Difference.	31 effective full-power days	no
3.3.1.4	NOTE: This Surveillance must be performed on the reactor trip bypass breaker before placing the bypass breaker in service. Perform Trip Actuating Device Operational Test.	31 days on a Staggered-Test Basis	yes
3.3.1.5	Perform Actuation Logic Test.	31 days on a Staggered-Test Basis	yes
3.3.1.6	NOTE: not required to be performed until [24] hours after Thermal Power is ≥ 50% rated thermal power. Calibrate excore channels to agree with incore detector measurements.	[92] effective full-power days	no
3.3.1.7	Perform Channel Operational Test.	[92] days	yes
3.3.1.8	NOTE: This Surveillance shall include verification that interlocks P-6 and P-10 are in their required state for existing unit conditions. Perform Channel Operational Test.	[92] days	yes

SR Number	Surveillance Requirement	Frequency	Detects Aging Degradation?
3.3.1.9	NOTE: Verification of setpoint is not required. Perform Trip Actuating Device Operational Test.	[92] days	yes
3.3.1.10	NOTE: This Surveillance shall include verification that the time constants are adjusted to the prescribed values. Perform Channel Calibration.	[18] months	no
3.3.1.11	NOTE: Neutron detectors are excluded from Channel Calibration. Perform Channel Calibration.	[18] months	no
3.3.1.12	NOTE: This Surveillance shall include verification of Reactor Coolant System resistance temperature detector bypass loop flow rate. Perform Channel Calibration.	[18] months	no
3.3.1.13	Perform Channel Operational Test.	18 months	yes
3.3.1.14	NOTE: Verfication of setpoint is not required. Perform Trip Actuating Device Operational Test.	[18] months	yes
3.3.1.15	NOTE: Verification of setpoint is not required. Perform Trip Actuating Device Operational Test.	NOTE: Only required when not performed within previous 31 days Before reactor startup	yes
3.3.1.16	NOTE: Neutron detectors are excluded from response time testing. Verify Reactor Trip System Response Time is within limits.	[18] months on a Staggered-Test Basis	yes
	Engineered Safety Feature Actuation System Instrumentation		
3.3.2.1	Perform Channel Check	12 hours	no
3.3.2.2	Perform Actuation Logic Test.	31 days on a Staggered-Test Basis	yes
3.3.2.3	NOTE: The continuity check may be excluded Perform Actuation Logic Test	31 days on a Staggered-Test Basis	yes
3.3.2.4	Perform Master Relay Test	31 days on a Staggered-Test Basis	yes
3.3.2.5	Perform Channel Operational Test	92 days	yes
3.3.2.6	Perform Slave Relay Test	[92] days	yes
3.3.2.7	NOTE: Verification of relay setpoints not required. Perform Trip Actuating Device Operational Test	[92] days	yes

SR Number	Surveillance Requirement	Frequency	Detects Aging Degradation?
3.3.2.8	Perform Trip Actuating Device Operational Test	[18] months	yes
3.3.2.9	NOTE: Not required to be performed for the turbine driven auxiliary feedwater pump until [24] hours after steam generator pressure is ≥ [1000] psig. Perform Channel Calibration	[18] months	no
3.3.2.10	NOTE: Not required to be performed for the turbine driven auxiliary feedwater pump until [24] hours after steam generator pressure is ≥ [1000] psig. Verify Engineered Safety Features Actuation System Response Times are within limit.	[18] months on a Staggered-Test Basis	yes
3.3.2.11	Perform Trip Actuation Device Operational Test	Once per reactor trip breaker cycle	yes

Appendix 8B

Reactor Trip Functions and Applicable Surveillance Requirements (Westinghouse)

Function	SR
1. Manual Reactor Trip	3.3.1.14
2. Power Range Neutron Flux	
a. High	3.3.1.1 3.3.1.2 3.3.1.7 3.3.1.11 3.3.1.16
b. Low	3.3.1.1 3.3.1.7 3.3.1.11 3.3.1.16
c. f(ΔI)	3.3.1.3 3.3.1.6
3. Power Range Neutron Flux Rate	
a. High Positive Rate	3.3.1.7 3.3.1.11
b. High Negative Rate	3.3.1.1 3.3.1.11
4. Intermediate Range Neutron Flux	3.3.1.1 3.3.1.8 3.3.1.11
5. Source Range Neutron Flux	3.3.1.1 3.3.1.8 3.3.1.11 3.3.1.16
6. Overtemperature ΔT	3.3.1.1 3.3.1.7 3.3.1.12 3.3.1.16
7. Overpower ΔT	3.3.1.1 3.3.1.7 3.3.1.12 3.3.1.16
8. Pressurizer Pressure	
a. Low	3.3.1.1 3.3.1.7 3.3.1.10 3.3.1.16
b. High	3.3.1.1 3.3.1.7 3.3.1.10 3.3.1.16
9. Pressurizer Water Level - High	3.3.1.1 3.3.1.7 3.3.1.10
10. Reactor Coolant Flow - Low	
a. Single Loop	3.3.1.1 3.3.1.7 3.3.1.10 3.3.1.16
b. Two Loops	3.3.1.1 3.3.1.7 3.3.1.10 3.3.1.16
11. Reactor Coolant Pump Breaker Position	
a. Single Loop	3.3.1.14
b. Two Loops	3.3.1.14
12. Undervoltage Reactor Coolant Pump	3.3.1.9 3.3.1.10 3.3.1.16
13. Underfrequency Reactor Coolant Pumps	3.3.1.9 3.3.1.10 3.3.1.16
14. Steam Generator Water Level - Low Low	3.3.1.1 3.3.1.7 3.3.1.10 3.3.1.16

Function	SR
15. Steam Generator Water Level - Low	3.3.1.1 3.3.1.7 3.3.1.10 3.3.1.16
Coincident with Steam Flow/ Feedwater Flow Mismatch	3.3.1.1 3.3.1.7 3.3.1.10 3.3.1.16
16. Turbine Trip	
a. Low Fluid Oil Pressure	3.3.1.10 3.3.1.15
b. Turbine Stop Valve Closure	3.3.1.10 3.3.1.15
17. Safety Injection Input from Engineered Safety Feature Actuation System	3.3.1.14
18. Reactor Trip System Interlocks	
a. Intermediate Range Neutron Flux, P-6	3.3.1.11 3.3.1.13

Function	SR
18. Reactor Trip System Interlocks (continued)	
b. Low Power Reactor Trips Block, P-7	3.3.1.11 3.3.1.13
c. Power Range Neutron Flux, P-8	3.3.1.11 3.3.1.13
d. Power Range Neutron Flux, P-9	3.3.1.11 3.3.1.13
e. Power Range Neutron Flux, P-10	3.3.1.11 3.3.1.13
f. Turbine Impulse Pressure, P-13	3.3.1.1 3.3.1.10 3.3.1.13
19. Reactor Trip Breakers	3.3.1.4
20. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms	3.3.1.4
21. Automatic Trip Logic	3.3.1.5

Appendix 8C

Engineered Safety Feature Actuation Functions and Applicable Surveillance Requirements (Westinghouse)

Function	SR
1. Safety Injection	
a. Manual Initiation	3.3.2.8
b. Automatic Actuation Logic and Actuation Relays	3.3.2.2 3.3.2.4 3.3.2.6
c. Containment Pressure - High 1	3.3.2.1 3.3.2.5 3.3.2.9 3.3.2.10
d. Pressurizer Pressure - Low	3.3.2.1 3.3.2.5 3.3.2.9 3.3.2.10
e. Steam Line Pressure	
(1) Low	3.3.2.1 3.3.2.5 3.3.2.9 3.3.2.10
(2) High Differential Pressure Between Steam Lines	3.3.2.1 3.3.2.5 3.3.2.9 3.3.2.10
f. High Steam Flow in Two Steam Lines	3.3.2.1 3.3.2.5 3.3.2.9 3.3.2.10
Coincident with T_{avg} - Low Low	3.3.2.1 3.3.2.5 3.3.2.9 3.3.2.10
g. High Steam Flow in Two Steam Lines	3.3.2.1 3.3.2.5 3.3.2.9 3.3.2.10
Coincident with Steam Line Pressure - Low	3.3.2.1 3.3.2.5 3.3.2.9 3.3.2.10
2. Containment Spray	
a. Manual Initiation	3.3.2.8
b. Automatic Actuation Logic and Actuation Relays	3.3.2.2 3.3.2.4 3.3.2.6
c. Containment Pressure	
High - 3 (High High)	3.3.2.1 3.3.2.5 3.3.2.9 3.3.2.10
High - 3 (Two-Loop Plants)	3.3.2.1 3.3.2.5 3.3.2.9 3.3.2.10
3. Containment Isolation	
a. Phase A Isolation	
(1) Manual Initiation	3.3.2.8
(2) Automatic Actuation Logic and Actuation Relays	3.3.2.2 3.3.2.4 3.3.2.6
(3) Safety Injection	(see function 1)

Function	SR
3. Containment Isolation (continued)	
b. Phase B Isolation	
(1) Manual Initiation	3.3.2.8
(2) Automatic Actuation Logic and Actuation Relays	3.3.2.2 3.3.2.4 3.3.2.6
(3) Containment Pressure High - 3 (High High)	3.3.2.1 3.3.2.5 3.3.2.9 3.3.2.10
4. Steam Line Isolation	
a. Manual Initiation	3.3.2.8
b. Automatic Actuation Logic and Actuation Relays	3.3.2.2 3.3.2.4 3.3.2.6
c. Containment Pressure - High 2	3.3.2.1 3.3.2.5 3.3.2.9 3.3.2.10
d. Steam Line Pressure	
(1) Low	3.3.2.1 3.3.2.5 3.3.2.9 3.3.2.10
(2) Negative Rate - High	3.3.2.1 3.3.2.5 3.3.2.9 3.3.2.10
e. High Steam Flow in Two Steam Lines	3.3.2.1 3.3.2.5 3.3.2.9 3.3.2.10
Coincident with T_{avg} - Low Low	3.3.2.1 3.3.2.5 3.3.2.9 3.3.2.10
f. High Steam Flow in Two Steam Lines	3.3.2.1 3.3.2.5 3.3.2.9 3.3.2.10
Coincident with Steam Line Pressure - Low	3.3.2.1 3.3.2.5 3.3.2.9 3.3.2.10

Function	SR
g. High Steam Flow	3.3.2.1 3.3.2.5 3.3.2.9 3.3.2.10
Coincident with Safety Injection	(see function 1)
Coincident with T_{avg} - Low Low	3.3.2.1 3.3.2.5 3.3.2.9 3.3.2.10
h. High High Steam Flow	3.3.2.1 3.3.2.5 3.3.2.9 3.3.2.10
Coincident with Safety Injection	(see function 1)
5. Turbine Trip and Feedwater Isolation	
a. Automatic Actuation Logic and Actuation Relays	3.3.2.2 3.3.2.4 3.3.2.6
b. Steam Generator Water Level - High High (P-14)	3.3.2.1 3.3.2.5 3.3.2.9 3.3.2.10
c. Safety Injection	(see function 1)
6. Auxiliary Feedwater	
a. Automatic Actuation Logic and Actuation Relays (Solid State Protection System)	3.3.2.2 3.3.2.4 3.3.2.6
b. Automatic Actuation Logic and Actuation Relays [Balance of Plant Engineered Safety Feature(s) Actuation System]	3.3.2.3
c. Steam Generator Water Level - Low Low	3.3.2.1 3.3.2.5 3.3.2.9 3.3.2.10
d. Safety Injection	(see function 1)
e. Loss of Offsite Power	3.3.2.7 3.3.2.9 3.3.2.10
f. Undervoltage Reactor Coolant Pump	3.3.2.7 3.3.2.9 3.3.2.10

Function	SR
g. Trip of all Main Feedwater Pumps	3.3.2.8 3.3.2.9 3.3.2.10
h. Auxiliary Feedwater Pump Suction Transfer on Suction Pressure - Low	3.3.2.1 3.3.2.7 3.3.2.9
7. Automatic Switchover to Containment Sump	
a. Automatic Actuation Logic Actuation Relays	3.3.2.2 3.3.2.4 3.3.2.6
b. Refueling Water Storage Level - Low Low	3.3.2.1 3.3.2.5 3.3.2.9 3.3.2.10
Coincident with Safety Injection (see function 1)	

Function	SR
7. Automatic Switchover to Containment Sump (continued)	
c. Refueling Water Storage Level - Low Low	3.3.2.1 3.3.2.5 3.3.2.9 3.3.2.10
Coincident with Safety Injection	(see function 1)
and	
Coincident with Containment Sump Level - High	3.3.2.1 3.3.2.5 3.3.2.9 3.3.2.10
8. Engineered Safety Feature(s) Actuation System Interlocks	
a. Reactor Trip, P-4	3.3.2.11
b. Pressurizer Pressure, P-11	3.3.2.1 3.3.2.5 3.3.2.9
c. T_{avg} - Low Low, P-12	3.3.2.1 3.3.2.5 3.3.2.9
d. Steam Generator Water Level - High High, P-14	3.3.2.1 3.3.2.5 3.3.2.9

Appendix 8D

Discussion of Aging Degradation Detection Methods

Improved surveillance methods have been identified that are more effective in detecting aging degradation in nuclear power plants than the current practices. Nuclear Plant Aging studies have investigated three advanced surveillance techniques for trending component degradation in the RPS: state-of-the-art infrared thermography data acquisition and analysis, redundant instrumentation monitoring, and multiple signal analyses.

Infrared thermography has been used in industry for many years; for the purpose of RPS monitoring, simple use of hand-held pyrometers and infrared scanners would be sufficient. However, recent enhancements using microcomputers have allowed infrared technology to progress from pass or fail testing to condition monitoring. Enhancements have been achieved by going from black and white thermograms to color, which allows greater visual resolution in detecting temperature changes. In addition, the ability to digitally store and recall temperature profiles of components has enhanced detection of incipient failures. An infrared thermography program would cover surveillance of RPS electrical equipment and modules. Infrared thermography is applicable for detecting RPS degradation when overheating would occur as a result of component degradation. The ability to trend with an infrared system is greatly dependent on the repeatability of the system to permit comparison of temperature profiles over time.

Redundant instrumentation monitoring is a computer-based process that can be used to monitor the calibration status of selected redundant instrumentation during operation. Use of this method could have practical advantages for verifying instrumentation calibration and reducing failures caused by routine testing and calibration of RPS modules. Redundant instrumentation monitoring can detect channel drift, which has been identified as one cause of age degradation in the RPS. Redundant instrumentation monitoring is used to identify instrumentation indicating anomalous behavior, such as setpoint drift. Redundant instrumentation monitoring can be used to monitor select redundant instrumentation throughout the fuel cycle and to perform calibrations only on those instruments indicating drift. Another NPAR approach under investigation is to calibrate only one of four redundant channels during outages and use this channel to verify calibration of the remaining three. By calibrating a different channel each cycle, all channels would be calibrated within eight years.

Multiple signal analyses can be used for condition monitoring and troubleshooting of deenergized circuits. This system applies direct current, low-frequency alternating current, and radio frequency testing techniques to monitor electrical characteristics of the plant circuits. The direct and alternating current measurements provide the lumped values of circuit loop resistance, insulation resistance, inductance, capacitance, quality, and dissipation factor. These measurements indicate circuit degradation, such as insulation deterioration, corrosion, and moisture intrusion. The radio frequency technique, known as time domain reflectometry, identifies the distributed resistance, inductance, and capacitance of the circuit and detects the location of circuit degradation. Test data show that multiple signal analyses provide information that indicates degradation in components (i.e., insulation degradation caused by harsh environments and corroded connections).

Results of the NPAR evaluation suggest that the improved surveillance methods mentioned above can detect potential RPS failures. These methods are less intrusive, more sensitive to measured parameters, more effective in detecting aging degradation, and less labor-intensive than current surveillance practices.

9.0 Service Water System

Service water systems (SWSs) perform vital safety functions, such as providing the final link between the reactor and the ultimate heat sink (e.g., sea, river, lake, cooling pond). Service water systems also provide cooling to safety-related equipment, such as emergency diesel generators and emergency core cooling systems. Depending on the design, all or part of SWSs may be exposed to raw or relatively aggressive treated water; therefore, SWS components are subject to a range of age-related degradation mechanisms.

A Nuclear Plant Aging Research (NPAR) assessment of SWSs was conducted by Pacific Northwest Laboratory (PNL) (Jarrell et al. 1989; Jarrell et al. 1992). This study provided the technical basis for the SWS standard technical specifications (STS) aging evaluation. Additional information was obtained from publications by Blahnik et al. (1992) and Johnson and Neitzel (1987).

9.1 Service Water System Description And Boundaries

The three types of nuclear plant SWSs are

- an open, once-through type that involves once-through flow of raw water from a lake, river, or ocean that functions as an ultimate heat sink; this water interacts directly with SWS components
- an open, recirculating type that involves a self-contained ultimate heat sink (i.e., a spray pond or dedicated cooling tower)
- a closed type that involves a large intermediate heat exchanger that isolates most of the SWS components from direct contact with raw water.

The major SWS components (Figure 9.1) include

- the intake structure, including canals or other diversion structures from the ultimate heat sink to the pump debris removal mechanism
- the pump gallery and structures, with all associated level control devices (e.g., wires, gates, valves) and instrumentation
- the SWS pumps, shaft, and motive sources, including controls, cables/wires, and electrical distribution system
- the piping distribution network from the SWS pumps to the heat exchangers, including all valves, manifolds, instruments, and logic networks
- the SWS side of the heat exchanger

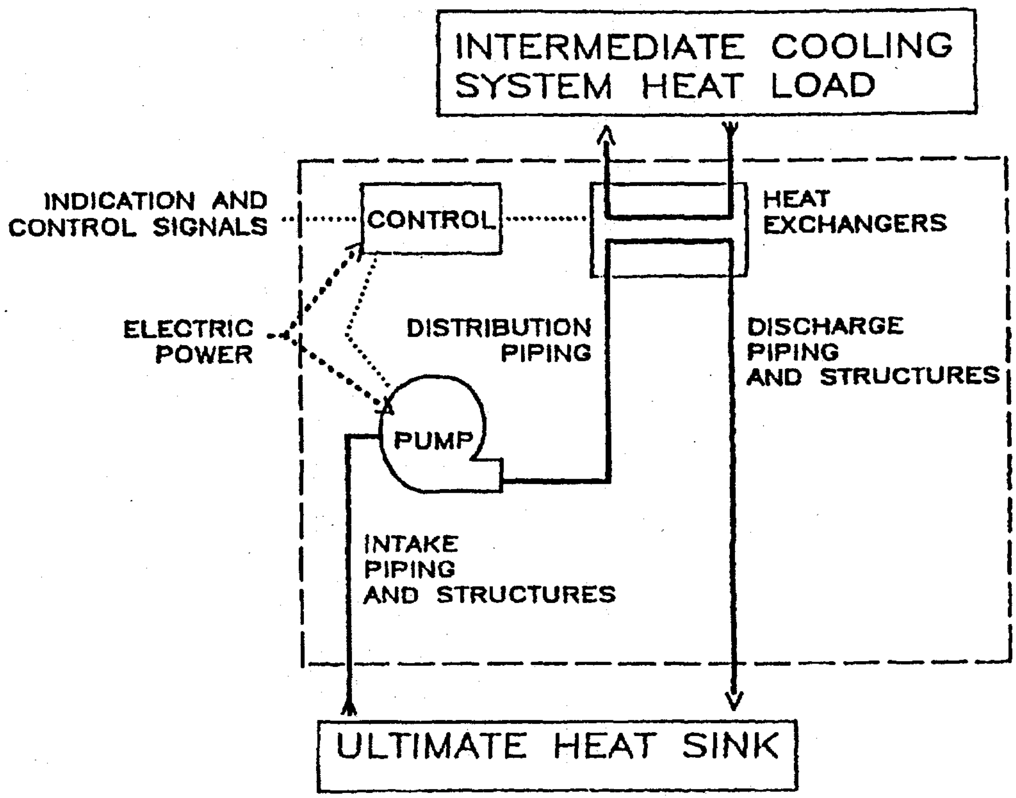

Figure 9.1. Service Water System

- the discharge piping, valves, and manifolds from the heat exchangers to the outlet/discharge structure

- the outlet/discharge structure, gates, and associated effluent channeling devices.

9.2 Stressors, Aging Mechanisms, and Aging Effects

To facilitate the aging evaluation, the SWS components were divided into the following groups:

- pumps and motors

- piping

- valves

- instrument and controls

- heat exchangers

- intake structures.

Known SWS stressors, the resulting aging mechanisms and aging degradation effects, and the locations where the stressors and aging mechanisms are operative are summarized in Table 9.1 for the major SWS components. The most important of the aging mechanisms for SWSs include biofouling, microbiologically influenced corrosion, corrosion, erosion, chemical attack, cavitation, and wear.

The aging stressors, mechanisms, and degradation effects that affect SWS valves can be found in Table 7.2 of this report.

Also noted in Table 9.1 is whether a particular aging degradation effect is detected by the current Westinghouse surveillance requirements (SRs). A potential deficiency in the SRs is identified when a particular aging effect is not detected by any existing SR (i.e., the component may experience undetected degradation). A list of recommended SRs to address the undetected degradation is presented in Section 9.6.

9.3 Degradation Detection Methods

Several methods that are effective in detecting aging degradation in SWSs have been developed, either historically or in response to specific aging concerns. The specific detection methods applicable to SWS aging degradation are identified in Table 9.1. Those methods that are useful and appropriate for inclusion in the SRs are identified in Section 9.6 as recommendations to improve or supplement the SRs.

Specific aging degradation detection methods for SWS valves are discussed in Section 7.0 of this report. Detection methods for the SWS instrument and control components are discussed in Section 8.0, Appendix 8D.

9.4 Evaluation of Existing Surveillance Requirements for Effectiveness in Detecting Aging Degradation

The SRs for SWSs for the Westinghouse plant STS are summarized in Appendix 9A. The existing SRs for SWSs focus primarily on operability concerns and not on addressing the detection and trending of aging degradation. For example, one SR requires that SWS pumps be demonstrated to start on an actual or simulated actuation signal. Yet another requires that the SWS automatic valves be demonstrated to align to their correct positions on an actual or simulated actuation signal; another requires verification that SWS valves are in the correct position.

None of the existing SRs is intended to monitor the onset of or directly indicate the age-related degradation of the SWS. Also, incomplete or ineffective root-cause analysis on failed SWS equipment has hampered efforts to detect and resolve age-related degradation.

Table 9.1. Summary of Detection Capability of Current SRs

SWS Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Methods	Addressed by STS SRs?[(a)]	Addressed by GL 89-13?
Pumps						
shafts & impellers	heat	wear, embrittlement, reduced material strength	cracking, scoring wiping, grooving, bowing, warping	visual inspection for leakage and blueing, acoustic emission, thermography, preventive maintenance tribology	no	no
	operation	wear	disc wall-thinning and impeller vane dimensional reduction	visual inspection for leakage	no	no
	chemical attack	corrosion, erosion, fatigue	cracking, fracture, reduced strength, disc wall-thinning, impeller vane dimensional reduction, local pitting	performance/ vibration monitoring, water impurity monitoring, preventive maintenance	no	no
	vibration	fatigue	cracking, distortion, seizure, loss of strength	performance/ vibration monitoring	no	no
	water hammer	fatigue, excessive structural loading, corrosion	cracking, fracture, bending, loosening, distortion, reduced strength	external visual for leakage, performance/ vibration monitoring, water impurity monitoring	no	no
	flow, low NPSH	cavitation, erosion	disc wall-thinning, impeller vane dimensional reduction, local pitting	performance/ vibration monitoring, acousitical monitoring, water impurity monitoring	no	no
casings	flow	erosion	wall-thinning	internal visual, analysis for thinning	no	no
	vibration	fatigue	loosening	performance/ vibration monitoring, visual inspection for leakage	no	no
	water hammer	fatigue, excessive structural loading	cracking, distortion, reduced strength	visual inspection for leakage, performance moitoring	no	no

(a) Representative SRs are listed where applicable.

Table 9.1. (contd)

SWS Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Methods	Addressed by STS SRs?[(a)]	Addressed by GL 89-13?
bearings	lubrication contamination and hardening	insufficient lubrication, increased wear, abrasion	interferences, cracked race, scored journal, damaged rolling element, widening tolerances	acoustical monitoring, temperature monitoring, visual inspection, lubricant analysis	no	no
	vibration, unbalanced rotating elements	increased wear	cracked race, scored journal, damaged rolling element, widening tolerances	performance/vibration monitoring, acoustical monitoring, visual inspection	no	no
	operation	wear	widening tolerances	performance monitoring, visual inspection	no	no
couplings	high temperature	excessive contact wear	coupling elastomer failure	shaft alignment, vibration monitoring, acoustic monitoring	no	no
	lack of lubrication	direct metal contact wear	broken spring or fastener	shaft alignment, vibration monitoring, acoustic monitoring	no	no
packing, seals, gaskets, & fasteners	contaminants, aggressive fluids	corrosion, increased wear	leakage	visual inspection for leakage and corrosion	no	no
	heat	embrittlement, overheating	cracking, distortion, loosening	visual inspection for leakage	no	no
	operation	abrasion, increased wear, erosion	cracking, breakdown	visual inspection for leakage	no	no
	unbalanced rotating assembly, vibration	fatigue, increased wear	cracking, distortion, loosening	acoustical monitoring, visual inspection for leakage	no	no
	water hammer	fatigue	distortion, cracking, loosening	performance monitoring	no	no
Motor Assembly						
contacts, windings	ohmic heating	oxidation, embrittlement, fatigue	shorting, increase in electrical resistance	resistance bridge testing, megger testing	no	no
				operation	3.7.8.3	no
contacts	overvoltage operation	arcing, current enhanced corrosion	shorting, fracture	visual	no	no
				operation	3.7.8.3	no
	vibration	fatigue, wear	loosening, fracture	torque verification	no	no

(a) Representative SRs are listed where applicable.

Table 9.1. (contd)

SWS Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Methods	Addressed by STS SRs?[(a)]	Addressed by GL 89-13?
motor	mechanical overload	overheating	loss of rated torque output, seizure	operation	3.7.8.3	no
				visual, polarization, index, resistant bridge test	no	no
	overvoltage operation	arcing	shorting	operation	3.7.8.3	no
				resistance bridge test	no	no
shaft	induction and heating contact	current enhanced corrosion	cracking, pitting, bowing	visual inspection, metalographic exam	no	no
rotor	ohmic heating	corrosion	cracking, softening	waveform analysis, visual	no	no
stator	overvoltage operation	fatigue	breakdown, shorting	resistance bridge testing, polarization index	no	no
	undervoltage and single phase operation	overheating	breakdown	polarization index testing, resistance bridge testing	no	no
	voltage imbalance	overheating	breakdown	polarization index testing, resistance bridge testing	no	no
bearings	overvoltage operation	wear, oxidation	breakdown, seizure	visual	no	no
	operation	wear	loosening, interferences	visual	no	no
moisture seal	humidity	corrosion	cracking, breakdown	visual	no	no
insulation	undervoltage and single phase operation	embrittlement	breakdown, fracture	visual, polarization index testing, resistance bridge testing	no	no
	voltage imbalance	embrittlement	loss of dielectric strength, fracture, breakdown	polarization index testing, resistance bridge testing	no	no
	mechanical overload	embrittlement	loss of dielectric strength, fracture, breakdown	visual, polarization index testing, resistance bridge testing	no	no
	humidity	corrosion	loss of dielectric strength, fracture, breakdown	polarization index testing, resistance bridge testing	no	no
	overvoltage operation	embrittlement	loss of dielectric strength, fracture, breakdown	polarization index testing, resistance bridge testing	no	no

(a) Representative SRs are listed where applicable.

Table 9.1. (contd)

SWS Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Methods	Addressed by STS SRs?[(a)]	Addressed by GL 89-13?
Piping						
walls	brackish water	microbiologically influenced corrosion, biofouling, biological reactions	blockage, flow reduction	external visual for leakage, ultrasonic examination, analysis for wall-thinning, increased hydraulic resistance	no	yes, Action 1, Enc. 1.D
	contaminants	corrosion, chemical reactions, fouling, oxidation	cracking, pitting perforation, flow reduction	external visual for leakage, ultrasonic examination, analysis for wall-thinning, increase in hydraulic resistance	no	no
	excessive fluid velocity	erosion, cavitation, abrasion	wall-thinning, elbow penetration	external visual for leakage, ultrasonic examination, analysis for wall-thinning	no	no
	operation	wear	wall-thinning	external visual for leakage, ultrasonic examination, analysis for wall-thinning	no	no
	vibrations	fatigue	loss of strength, cracking,	external visual for leakage, analysis	no	no
	water hammer	fatigue	cracking, fracture	external visual for leakage	no	no
flanges and gaskets	brackish water	microbiologically influenced corrosion, biofouling, biological reactions	blockage, increase in frictional resistance	external visual for leakage, analysis for wall- thinning, increase in frictional resistance	no	no
	contaminants	corrosion, chemical reactions, fouling, oxidation	contamination, cracking	external visual for leakage, analysis for wall-thinning, increase in frictional resistance	no	no
	flow	erosion, cavitation, wear	wall-thinning wear-reduction	external visual for leakage, analysis for wall-thinning	no	no
	operation	wear	wall-thinning	external visual for leakage, analysis for wall-thinning	no	no
	vibrations	fatigue	loss of strength, cracking, wear-reduction	external visual for leakage, analysis	no	no
	water hammer	fatigue	cracking, fracture	external visual for leakage	no	no

(a) Representative SRs are listed where applicable.

Table 9.1. (contd)

SWS Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Methods	Addressed by STS SRs?[(a)]	Addressed by GL 89-13?
Valves						
See Table 7.2	See Table 7.2	See Table 7.2	See Table 7.2	See Table 7.2	3.7.8.2 for automatic valve operation	no
Instrument & Controls						
seals, gaskets, other organic compounds	heat, operation, pressure, thermal cycling, vibration	curing, chemical reactions, embrittlement	hardening, loss of integrity, softening, cracking	external/internal visual, preventive maintenance	no	no
connectors and linkages	vibration, impact, contamination	wear	binding/lockup, drift, loosening, loss of mechanical strength, sticking open/shut	external visual, tribology	no	no
	operation, lack of lubrication	fatigue, over torque	binding/lockup, drift, loosening, sticking open/shut	operation	3.7.8.2	no
pneumatic components	humidity	oxidation, corrosion	loss of integrity	external/internal visual, pressure test	no	no
	thermal cycling	differential thermal expansion	loss of integrity	external/internal visual, temperature monitoring	no	no
	contaminants	fouling	blockage, sticking open/shut	internal visual	no	no
hydraulic components	operation	wear, embrittlement	loss of integrity, binding/lockup, breakdown	operation	3.7.8.2	no
				internal visual, preventive maintenance	no	no
	contaminants	fouling, abrasion	increase in frictional resistance	internal visual	no	no
hydraulic fluid	contamination	fouling	breakdown	fluid analysis	no	no
	heat	oxidation	breakdown	fluid analysis	no	no

(a) Representative SRs are listed where applicable.

Table 9.1. (contd)

SWS Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Methods	Addressed by STS SRs?[(a)]	Addressed by GL 89-13?
circuit breakers	operation	wear, galling, pitting	increase in electrical resistance, increase in response time	operation	3.7.8.2, 3.7.8.3	no
				resistance bridge testing, preventive maintenance	no	no
	contaminants	pitting, arcing, corrosion	melting, seizure, sticking shut	internal visual	no	no
	humidity	arcing, galling, pitting, oxidation	sticking open/shut, drift	internal visual	no	no
contacts	ohmic heating	overheating	sticking open/shut, melting	resistance bridge testing	no	no
	operation, contamination	wear, pitting, galling, corrosion	sticking open/shut	operation	3.7.8.2, 3.7.8.3	no
	overvoltage/ undervoltage operation	overheating, arcing	sticking open/shut, increase in response time, resistance, melting	resistance bridge testing	no	no
relays	ohmic heating	high-temperature breakdown	breakdown of insulation, decrease in electrical resistance, melting	resistance bridge testing	no	no
	operation	wear, pitting, galling	drift, sticking open/shut	operation	3.7.8.2, 3.7.8.3	no
				resistance bridge testing	no	no
	overvoltage/ undervoltage operation	overheating, arcing	sticking open/shut, increase in response time, decrease in electrical resistance, melting	resistance bridge testing	no	no
sensors	humidity	oxidation, chemical reactions, corrosion	decrease/increase in electrical resistance, drift	operation, calibration check, resistance bridge test	no	no
	heat	overheating, differential thermal expansion	decrease/increase in electrical resistance, breakdown of insulation	operation, calibration check resistance bridge test	no	no
	operation	wear, fatigue	seizure, breakdown, increase in electrical resistance	operation, calibration check, resistance bridge test	no	no

(a) Representative SRs are listed where applicable.

Table 9.1. (contd)

SWS Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Methods	Addressed by STS SRs?[a]	Addressed by GL 89-13?
solenoids	operation	wear, thermal cycling, corrosion	reduction in solenoid force, increase in stroke time	operation	3.7.8.2, 3.7.8.3	no
				internal visual	no	no
	contaminants	arcing, fouling	blockage, binding/lockup, sticking open/shut	internal visual	no	no
	humidity	corrosion, arcing, galling, pitting	decrease/increase in electrical resistance, shorting, open circuit	internal/external visual	no	no
	environmental and ohmic heating	thermal cycling, oxidation, corrosion	shorting, melting, open circuit	resistance bridge testing	no	no
Heat Exchangers						
tubes	chemicals	corrosion	blockage, loss of mechanical strength	fluid anaylsis, operation, internal visual, ultrasonic examination, ET, hydraulic resistance, hydrostatic testing	no	no
		chemical reactions	blockage, wall-thinning, material breakdown	fluid anaylsis, operation, internal visual, ultrasonic examination, ET, increased hydraulic resistance, hydrostatic testing, leakage	no	no
		fouling	blockage	operation, internal visual, ultrasonic examination, increased hydraulic resistance	no	Action II, Enc. 2, I & II
		pitting	wall-thinning, loss of mechanical strength	operation, internal visual, ultrasonic examination, ET, leakage, hydrostatic testing	no	no
	contaminants	fouling	blockage	operation, internal visual, increased hydrualic resistance	no	Action II, Enc. 2, I & II

(a) Representative SRs are listed where applicable.

Table 9.1. (contd)

SWS Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Methods	Addressed by STS SRs?[a]	Addressed by GL 89-13?
tubes	contaminants	abrasion, erosion	wall-thinning	operation, internal visual, ultrasonic examination, ET, leakage, hydrostatic testing	no	no
		biofouling	blockage, biological reactions, wall-thinning, loss of mechanical strength	operation, internal visual, ultrasonic examination, ET, leakage, increased hydrualic resistance	no	Act II, Enc. 2, I & II
	thermal-cycling	creep, fatigue	distortion, fracture, cracking, tube-to-tubesheet separation	operation, internal visual, ultrasonic examination, ET, leakage	no	no
	high fluid velocity	erosion	wall-thinning	operation, internal visual, ultrasonic examination, ET, leakage	no	no
	vibration	wear, fatigue	wall-thinning, distortion, fracture, cracking, loss of mechanical strength	operation, internal visual, ultrasonic examination, ET, leakage	no	no
tubesheets	chemicals	corrosion	blockage, loss of mechanical strength	internal visual, ultrasonic examination, ET	no	Act II, Enc. 2, I & II
		chemical reactions	material breakdown, oxidation, metal loss	operation, internal visual, ultrasonic examination, leakage	no	no
		fouling	blockage, reduction of heat transfer	operation, internal visual, preventive maintenance	no	Act II, Enc. 2, I & II
	high fluid vlocity	erosion	metal loss, cutting	operation, internal visual, ultrasonic examination, leakage	no	no
	thermal cycling	differential thermal expansion	distortion, separation, interferences, loss of integrity, loosening	operation, internal visual, ultrasonic examination, leakage	no	no
		creep, fatigue	cracking, fracture, loss of mechanical strength	operation, internal visual, ultrasonic examination, leakage	no	no

(a) Representative SRs are listed where applicable.

Table 9.1. (contd)

SWS Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Methods	Addressed by STS SRs?[a]	Addressed by GL 89-13?
waterboxes	chemicals	corrosion	blockage, loss of mechanical strength	operation, internal visual, ultrasonic examination, leakage	no	Act II, Enc. 2, I & II
		chemical reactions	material breakdown, oxidation, wall-thinning	operation, internal visual, ultrasonic examination, leakage	no	no
		fouling	blockage	operation, internal visual	no	Act II, Enc. 2, I & II
		pitting	wall-thinning, loss of mechanical strength	operation, internal visual, ultrasonic examination, leakage	no	no
	contaminants	fouling	blockage	operation, internal visual, preventive maintenance	no	Act II, Enc. 2, I & II
waterboxes	contaminants	abrasion	wall-thinning	operation, internal visual, ultrasonic examination, leakage	no	no
		biofouling	blockage, biological reactions, loss of mechanical strength	operation, internal visual, ultrasonic examination, leakage, preventive maintenance	no	Act II, Enc. 2, I & II
	high fluid velocity	erosion	wall-thinning, cutting	operation, internal visual, ultrasonic examination, leakage	no	no
	thermal cycling	fatigue	fracture, cracking, loss of mechanical strength	operation, internal visual, ultrasonic examination, leakage	no	no
		differential thermal expansion	distortion, loosening, interferences	operation, internal visual, ultrasonic examination, leakage	no	no
Intake Structures						
intake	brackish water	microbiologically influenced corrosion, biofouling, biological reactions	blockage	visual	no	yes (action 1, Enc. 1.A)
	flow	wear	wear-reduction	visual	no	no
	freezing/thawing	swelling/wear	cracking	visual	no	no
	contaminants	microbiologically influenced corrosion, biofouling, biological reactions	blockage	operation, visual	no	yes (action 1, enc. 1.A & D)

(a) Representative SRs are listed where applicable.

9.5 Evaluation of Existing Surveillance Requirements for Possible Contributions to Premature Aging Degradation

As stated in Section 9.4, the existing SRs for SWSs are designed primarily to determine operability and not to detect and trend aging degradation. Most SRs require verification of a condition or status, such as verifying valve position, which generally would have no aging impact. The few SRs that require demonstration or operation are on such a low frequency as to render their aging effects negligible. Thus, existing SRs for the SWS do not contribute to aging in that the test methods and the frequency of testing do not cause premature aging degradation.

9.6 Recommendations to Improve or Supplement Surveillance Requirements

9.6.1 Generic Letter 89-13

Generic Letter (GL) 89-13, "Service Water System Problems Affecting Safety-Related Equipment," dated July 18, 1989, and provided in Appendix 9B, contains specific recommended actions to be taken to address SWS problems. These recommended actions are intended to confirm that the SWS will perform its intended function in accordance with the licensing basis for the plant (i.e., to ensure adequate cooling for associated safety-related heat loads). The GL 89-13 provisions address 1) control of flow blockage and biofouling; 2) heat transfer capability (i.e., performance) of open-cycle safety-related heat exchangers, (closed-cycle exchangers are included selectively, if required by degraded performance trends); 3) inspection and maintenance programs for open-cycle piping and components for corrosion, erosion, coating failure, silting, and biofouling, including corrective actions; 4) confirmation that the SWS will perform its intended function; and 5) confirmation that maintenance practices, operating and emergency procedures, and training are adequate.

One supplement to the GL has been published that presents the results of the U.S. Nuclear Regulatory Commission (NRC)-sponsored public workshops regarding the SWS programs. Several Information Notices (see Appendix 9C) that address the continuing SWS problems also have been issued.

A number of significant aging degradation effects and appropriate detection methods that are applicable to SWS are listed in Table 9.1. Many of these effects are not addressed by current SRs. With implementation of a SWS program in response to the GL, an additional number of these aging degradation effects may be addressed. The following recommendations of GL 89-13, as modified by PNL staff, apply to the open portion of SWS and are suggested for incorporation into SRs.

1. Systematic Root-Cause Analysis

A systematic method for determining the root cause of an SWS component failure was developed for the NPAR program (Jarrell et al. 1992). This methodology focuses resources on mitigating the underlying cause of failure rather than the treatment of an indicating symptom. It is recommended that a utility-specific version of this approach be incorporated into the SR framework.

2. Heat Exchangers

Heat exchanger tubes, tubesheets, and waterboxes should be visually examined once every other refueling cycle or whenever opened for any other reason for evidence of corrosion, erosion, biofouling, metal leaching, debris accumulation, organic attack, or inorganic attack. Heat exchangers should be subjected to a performance test per the requirements of GL 89-13 once every three months for those that are normally in service and in stand-by to verify heat transfer capability. Test results should be trended over time to note the degradation characteristics for the unit. The minimum frequency for heat exchangers that are normally in service and in stand-by may be extended to a maximum of 18 months, based upon being able to demonstrate, upon a review of the trending data, that the applicable heat transfer capability meets safety analysis report, STS, and plant requirements.

3. Piping

Piping and associated gaskets should be visually examined once every refueling outage for evidence of leakage and for continuity of protective coatings. Additionally, piping should be subjected to a flow test once every refueling outage for evidence of flow degradation. Test results should be trended over time to anticipate potential effects of degradation.

4. Intake Structures

Intake structures should be visually examined once every refueling cycle for evidence of excessive biofouling, corrosion, or sediment accumulation.

9.6.2 Recommendations From the NPAR Aging Assessments

The NPAR studies of the SWS have developed additional recommendations that address age-related issues in the SRs, making them more useful and effective in detecting, trending, and monitoring SWS degradation before failure. The following recommendations are suggested for incorporation into SRs for risk-significant and prioritized components and subcomponents in the open portion of SWS.

1. Pumps

Unless otherwise dictated by experience, pump impellers, casings, packing, and seals should be visually examined once every other refueling cycle, or whenever opened for any other reason, for evidence of wear, erosion, cavitation, biofouling, debris accumulation, or inorganic attack. Pumps that are either normally in service or stand-by should be subjected to an operational performance test to demonstrate the adequacy of pump pressure/flow characteristics once every three months. If pumps that are normally in stand-by cannot be subjected to an operational test due to plant conditions or plant line-up, the minimum testing frequency should be once every refueling cycle.

Test results should be trended over time to note potential degradation. The minimum frequency for pumps that are normally in service and in stand-by may be extended up to a maximum of 18 months based upon being able to demonstrate, upon a review of the trending data, that pump pressure/flow characteristics are adequate to meet STS and plant requirements. Pump/motor bearings should be subjected to continuous, or at least weekly, vibration monitoring to demonstrate that bearing vibration is at acceptable levels, with attendant trending.

2. Valves

Valve seats, discs/gates, swing arms, and stuffing boxes should be visually examined once every other refueling cycle, or whenever opened for any other reason, for evidence of degradation, debris accumulation, or biofouling. All SWS valves that are exposed to raw or aggressive water should be subjected to an operational test once every refueling outage to ensure proper operation. Test results should be trended over time to note potential degradation. Additional testing of valves, critical to the operation of the SWS, is discussed in Section 7.0 of this report.

9.6.3 Implementing Suggested Recommendations

A list of suggested SRs for SWS components with associated surveillance frequencies to implement the recommendations from the NPAR aging assessments is provided in Table 9.2. These recommended SRs address the potential for undetected SWS component degradation that was identified in Table 9.1, except for those effects with a very low probability of failure of the component or those that are more appropriately addressed by an effective maintenance program.

An SR is not specified in Table 9.2 for each individual SWS system component; rather, the individual degradation detection methods that apply to a particular degradation effect on a component are grouped to form a generically stated SR. For example, each visual examination that is deemed appropriate to detect a potential undetected component degradation effect, as reflected in Table 9.1, is combined into a single recommended SR in Table 9.2. Each of these generic SRs would then be expanded by writing them for SWS components throughout the STS in a form consistent with that of existing SRs, as identified in Appendix 9A.

Table 9.2. Surveillance Requirement Recommendations to Detect and Trend SWS Aging Degradation

Surveillance Requirement[a]	Frequency of Action
Verify that heat exchanger tubes, tubesheets, and waterboxes show no evidence of excessive corrosion, erosion, biofouling, metal leaching, debris accumulation, organic attack, or inorganic attack.	36 months or whenever opened
Trend parameters that demonstrate the adequacy of the heat transfer capability of the heat exchanger.[b]	three months in service and stand-by[d]
Verify that piping and associated pressure boundary items show no evidence of excessive leakage.	18 months
Trend parameters that demonstrate that flow in SWS piping shows no evidence of excessive flow degradation.[b]	18 months
Verify that intake structures show no evidence of excessive biofouling, corrosion, or sedimentation.[b]	18 months
Verify that pump components show no evidence of excessive wear, erosion, cavitation, inorganic attack, blockage, or biofouling.	36 months
Trend parameters that demonstrate the adequacy of pump pressure/flow characteristics.	three months[c],[d]
Trend parameters that demonstrate that pump bearing vibration is at acceptable levels.	seven days
Verify that valve components show no evidence of excessive degradation, blockage, or biofouling.	36 months or whenever opened
Trend parameters that demonstrate the operability of valves that are exposed to raw or aggressive water or biofouling.	18 months

(a) In the event of component failure, root-cause analysis of the component shall be performed to determine the underlying cause of failure.

(b) These recommended SRs are in accordance with GL 89-13.

(c) In the event that the pump cannot be tested due to plant condition or plant line-up, the minimum frequency shall be 18 months. Vibration monitoring shall be coincident with pump testing or upon scheduled restart after an extended shutdown.

(d) The minimum frequency may be lengthened to a maximum of 18 months upon being able to demonstrate, based upon a review of the component trending data, that the degradation mechanisms that are active on the component require a longer time period to show degradation. When warranted by a review of component trending data, frequency may be shortened to more accurately trend potential.

Appendix 9A

Summary of Service Water System Surveillance Requirements From Westinghouse STS

SR Number	Surveillance Requirement	Frequency	Detects Aging Degradation?
	Service Water System		
3.7.8.1	NOTE: Isolation of SWS flow to individual components does not render the SWS inoperable. Verify that each SWS manual, power-operated, and automatic valve in the flow path servicing safety-related equipment, and that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days	no
3.7.8.2	Verify that each SWS automatic valve in the flow path actuates to the correct position on the actual or simulated actuation signal.	[18 months]	yes
3.7.8.3	Verify that each SWS pump starts automatically on an actual or simulated actuation signal.	[18 months]	yes

Appendix 9B

Generic Letter 89-13 - Service Water System Problems Affecting Safety-Related Equipment

UNITED STATES
NUCLEAR REGULATORY COMMISSION
Washington, D.C. 20555

July 18, 1989

TO: ALL HOLDERS OF OPERATING LICENSES OR CONSTRUCTION PERMITS FOR NUCLEAR POWER PLANTS

SUBJECT: SERVICE WATER SYSTEM PROBLEMS AFFECTING SAFETY-RELATED EQUIPMENT (GENERIC LETTER 89-13)

Purpose:

Nuclear power plant facilities of licensees and applicants must meet the minimum requirements of the General Design Criteria (GDC) in 10 CFR Part 50, Appendix A. In particular, "GDC 44--Cooling Water" requires provision of a system (here called the service water system) "to transfer heat from structures, systems, and components important to safety to an ultimate heat sink" (UHS). "GDC 45--Inspection of Cooling Water System" requires the system design "to permit appropriate periodic inspection of important components, such as heat exchangers and piping, to assure the integrity and capability of the system." "GDC 46--Testing of Cooling Water System" requires the design "to permit appropriate periodic pressure and functional testing."

In addition, nuclear power plant facilities of licensees and applicants must meet the minimum requirements for quality assurance in 10 CFR Part 50, Appendix B. In particular, Section XI, "Test Control," requires that "a test program shall be established to assure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service is identified and performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in applicable design documents."

Recent operating experience and studies have led the NRC to question the compliance of the service water systems in the nuclear power plants of licensees and applicants with these GDC and quality assurance requirements. Therefore, this Generic Letter is being issued to require licensees and applicants to supply information about their respective service water systems to assure the NRC of such compliance and to confirm that the safety functions of their respective service water systems are being met.

Background:

Bulletin No. 81-03: The NRC staff has been studying the problems associated with service water cooling systems for a number of years. At Arkansas Nuclear One, Unit 2, on September 3, 1980, the licensee shut down the plant when the NRC Resident Inspector discovered that the service water flow rate through the containment cooling units did not meet the technical specification requirement. The licensee determined the cause to be extensive flow blockage by Asiatic clams (Corbicula species, a non-native fresh water bivalve mollusk). Prompted by this event and after determining that it represented a generic problem of safety significance, the NRC issued Bulletin No. 81-03, "Flow Blockage of Cooling Water to Safety System Components by Corbicula sp. (Asiatic Clam) and Mytilus sp. (Mussel)."

The bulletin required licensees and applicants to assess macroscopic biological fouling (biofouling) problems at their respective facilities in accordance with specific actions. A careful assessment of responses to the bulletin indicated that existing and potential fouling problems are generally unique to each facility ("Closeout of IE Bulletin 81-03...", NUREG/CR-3054), but that surprisingly, more than half the 129 nuclear generating units active at that time were considered to have a high potential for biofouling. At that time, the activities of licensees and applicants for biofouling detection and control ranged widely and, in many instances, were judged inappropriate to ensure safety system reliability. Too few of the facilities with high potential for biofouling had adopted effective control programs.

Information Notice No. 81-21: After issuance of Bulletin No. 81-03, one event at San Onofre Unit 1 and two events at the Brunswick station indicated that conditions not explicitly discussed in the bulletin can occur and cause loss of direct access to the UHS. These conditions include

1. Flow blockage by debris from shellfish other than Asiatic clams and blue mussels.

2. Flow blockage in heat exchangers causing high pressure drops that can deform baffles and allow flow to bypass heat exchanger tubes.

3. A change in operating conditions, such as a change from power operation to a lengthy outage, that permits a buildup of biofouling organisms.

The NRC issued Information Notice No. 81-21 to describe these events and concerns.

Generic Issue 51: By March 1982, several reports of serious fouling events caused by mud, silt, corrosion products, or aquatic bivalve organisms in open-cycle service water systems had been received. These events led to plant shutdowns, reduced power operation for repairs and modifications, and degraded modes of operation. This situation led the NRC to establish Generic Issue 51, "Improving the Reliability of Open-Cycle Service Water Systems." To resolve this issue, the NRC initiated a research program to compare alternative surveillance and control programs to minimize the effects of fouling on plant safety. Initially, the program was restricted to a study of biofouling, but in 1987 the program was expanded to also address fouling by mud, silt, and corrosion products.

This research program has recently been completed and the results have been published in "Technical Findings Document for Generic Issue 51...," NUREG/CR-5210. The NRC has concluded that the issue will be resolved when licensees and applicants implement either the recommended surveillance and control program described below (Enclosure 1) or its equivalent for the service water system at their respective facilities. Many licensees experiencing service water macroscopic biofouling problems at their plants have found that these techniques will effectively prevent recurrence of such problems. The examination of alternative corrective action programs is documented in "Value/Impact Analysis for Generic Issue 51...," NUREG/CR-5234.

Continuing Problems: Since the advent of Generic Issue 51, a considerable number of events with safety implications for the service water system have been reported. A number of these have been described in information notices, which are listed in "Information Notices Related to Fouling Problems in Service Water Systems" (Enclosure 3). Several events have been reported within the past 2 years: Oconee Licensee Event Report (LER) 50-269/87-04, Rancho Seco LER 50-312/87-36, Catawba LER 50-414/88-12, and Trojan LER 50-344/88-29. In the fall of 1988, the NRC conducted a special announced safety system functional inspection at the Surry station to assess the operational readiness of the service water and recirculation spray systems. A number of regulatory violations were identified (NRC Inspection Reports 50-280/88-32 and 50-281/88-32).

AEOD Case Study: In 1987, the Office for Analysis and Evaluation of Operational Data (AEOD) in the NRC initiated a systematic and comprehensive review and evaluation of service water system failures and degradations at light water reactors from 1980 to early 1987. The results of this AEOD case study are published in "Operating Experience Feedback Report - Service Water System Failures and Degradations," NUREG-1275, Volume 3 (Enclosure 4).

Of 980 operational events involving the service water system reported during this period, 276 were deemed to have potential generic safety significance. A majority (58 percent) of these events with generic significance involved system fouling. The fouling mechanisms included corrosion and erosion (27 percent), biofouling (10 percent), foreign material and debris intrusion (10 percent), sediment deposition (9 percent), and pipe coating failure and calcium carbonate deposition (1 percent).

The second most frequently observed cause of service water system degradations and failures is personnel and procedural errors (17 percent), followed by seismic deficiencies (10 percent), single failures and other design deficiencies (6 percent), flooding (4 percent), and significant equipment failures (4 percent).

During this period, 12 events involved a complete loss of service water system function. Several of the significant causes listed above for system degradation were also contributors to these 12 events involving system failure.

The study identified the following actions as potential NRC requirements.

1. Conduct, on a regular basis, performance testing of all heat exchangers, which are cooled by the service water system and which are needed to perform a safety function, to verify heat exchanger heat transfer capability.

2. Require licensees to verify that their service water systems are not vulnerable to a single failure of an active component.

3. Inspect, on a regular basis, important portions of the piping of the service water system for corrosion, erosion, and biofouling.

4. Reduce human errors in the operation, repair, and maintenance of the service water system.

Recommended Actions To Be Taken by Addressees:

On the basis of the discussion above, the NRC requests that licensees and applicants perform the following or equally effective actions to ensure that their service water systems are in compliance and will be maintained in compliance with 10 CFR Part 50, Appendix A, General Design Criteria 44, 45, and 46 and Appendix B, Section XI. If a licensee or applicant chooses a course of action different from the recommendations below, the licensee or applicant should document and retain in appropriate plant records a justification that the heat removal requirements of the service water system are satisfied by use of the alternative program.

Because the characteristics of the service water system may be unique to each facility, the service water system is defined as the system or systems that transfer heat from safety-related structures, systems, or components to the UHS. If an intermediate system is used between the safety-related items and the system rejecting heat to the UHS, it performs the function of a service water system and is thus included in the scope of this Generic Letter. A closed-cycle system is defined as a part of the service water system that is not subject to significant sources of contamination, one in which water chemistry is controlled, and one in which heat is not directly rejected to a heat sink. If all these conditions are not satisfied, the system is to be considered an open-cycle system in regard to the specific actions required below. (The scope of closed cooling water systems is discussed in the industrial standard "Operation and Maintenance of Nuclear Power Plants," ASME/ANSI OM-1987, Part 2.)

I. For open-cycle service water systems, implement and maintain an ongoing program of surveillance and control techniques to significantly reduce the incidence of flow blockage problems as a result of biofouling. A program acceptable to the NRC is described in "Recommended Program to Resolve Generic Issue 51" (Enclosure 1). It should be noted that Enclosure 1 is provided as guidance for an acceptable program. An equally effective program to preclude biofouling would also be acceptable. Initial activities should be completed before plant startup following the first refueling outage beginning 9 months or more after the date of this letter. All activities should be documented and all relevant documentation should be retained in appropriate plant records.

II. Conduct a test program to verify the heat transfer capability of all safety-related heat exchangers cooled by service water. The total test program should consist of an initial test program and a periodic retest program. Both the initial test program and the periodic retest program should include heat exchangers connected to or cooled by one or more open-cycle systems as defined above. Operating experience and studies indicate that closed-cycle service water systems, such as component cooling water systems, have the potential for significant fouling as a consequence of aging-related in-leakage and erosion or corrosion. The need for testing of closed-cycle system heat exchangers has not been considered necessary because of the assumed high quality of existing chemistry control programs. If the adequacy of these chemistry control programs cannot be confirmed over the total operating history of the plant or if during the conduct of the total testing program any unexplained downward trend in heat exchanger performance is identified that cannot be remedied by maintenance of an open-cycle system, it may be necessary to selectively extend the test program and the routine inspection and maintenance program addressed in Action III, below, to the attached closed-cycle systems.

A program acceptable to the NRC for heat exchanger testing is described in "Program for Testing Heat Transfer Capability" (Enclosure 2). It should be noted that Enclosure 2 is provided as guidance for an acceptable program. An equally effective program to ensure satisfaction of the heat removal requirements of the service water system would also be acceptable.

Testing should be done with necessary and sufficient instrumentation, though the instrumentation need not be permanently installed. The relevant temperatures should be verified to be within design limits. If similar or equivalent tests have not been performed during the past year, the initial tests should be completed before plant startup following the first refueling outage beginning 9 months or more after the date of this letter.

As a part of the initial test program, a licensee or applicant may decide to take corrective action before testing. Tests should be performed for the heat exchangers after the corrective actions are taken to establish baseline data for future monitoring of heat exchanger performance. In the periodic retest program, a licensee or applicant should determine after three tests the best frequency for testing to provide assurance that the equipment will perform the intended safety functions during the intervals between tests. Therefore, in the periodic retest program, to assist that determination, tests should be performed for the heat exchangers before any corrective actions are taken. As in the initial test program, tests should be repeated after any corrective actions are taken to establish baseline data for future monitoring of heat exchanger performance.

An example of an alternative action that would be acceptable to the NRC is frequent regular maintenance of a heat exchanger in lieu of testing for degraded performance of the heat exchanger. This alternative might apply to small heat exchangers, such as lube oil coolers or pump bearing coolers or readily serviceable heat exchangers located in low radiation areas of the facility.

In implementing the continuing program for periodic retesting of safety-related heat exchangers cooled by service water in open-cycle systems, the initial frequency of testing should be at least once each fuel cycle, but after three tests, licensees and applicants should determine the best frequency for testing to provide assurance that the equipment will perform the intended safety functions during the intervals between tests and meet the requirements of GDC 44, 45, and 46. The minimum final testing frequency should be once every 5 years. A summary of the program should be documented, including the schedule for tests, and all relevant documentation should be retained in appropriate plant records.

III. Ensure by establishing a routine inspection and maintenance program for open-cycle service water system piping and components that corrosion, erosion, protective coating failure, silting, and biofouling cannot degrade the performance of the safety-related systems supplied by service water. The maintenance program should have at least the following purposes:

A. To remove excessive accumulations of biofouling agents, corrosion products, and silt;

B. To repair defective protective coatings and corroded service water system piping and components that could adversely affect performance of their intended safety functions.

This program should be established before plant startup following the first refueling outage beginning 9 months after the date of this letter. A description of the program and the results of these maintenance inspections should be documented. All relevant documentation should be retained in appropriate plant records.

IV. Confirm that the service water system will perform its intended function in accordance with the licensing basis for the plant. Reconstitution of the design basis of the system is not intended. This confirmation should include a review of the ability to perform required safety functions in the event of failure of a single active component. To ensure that the as-built system is in accordance with the appropriate licensing basis documentation, this confirmation should include recent (within the past 2 years) system walkdown inspections. This confirmation should be completed before plant startup following the first refueling outage beginning 9 months or more after the date of this letter. Results should be documented and retained in appropriate plant records.

V. Confirm that maintenance practices, operating and emergency procedures, and training that involves the service water system are adequate to ensure that safety-related equipment cooled by the service water system will function as intended and that operators of this equipment will perform effectively. This confirmation should include recent (within the past 2 years) reviews of practices, procedures, and training modules. The intent of this action is to reduce human errors in the operation, repair, and maintenance of the service water system. This confirmation should be completed before plant startup following the first refueling outage beginning 9 months or more after the date of this letter. Results should be documented and retained in appropriate plant records.

Reporting Requirements:

Pursuant to the provisions of Section 182a of the Atomic Energy Act of 1954, as amended, and 10 CFR 50.54(f), each licensee and applicant shall advise the NRC whether it has established programs to implement Recommendations I-V of this Generic Letter or that it has pursued an equally effective alternative course of action. Each addressee's response to this requirement for information shall be made to the NRC within 180 days of receipt of this Generic Letter. Licensees and applicants shall include schedules of plans for implementation of the various actions. The detailed documentation associated with this Generic Letter should be retained in appropriate plant records.

The response shall be submitted to the appropriate regional administrator under oath and affirmation under the provisions of Section 182a, Atomic Energy Act of 1954, as amended and 10 CFR 50.54(f). In addition, the original cover letter and a copy of any attachment shall be transmitted to the U.S. Nuclear Regulatory Commission, Document Control Desk, Washington DC 20555, for reproduction and distribution.

In addition to the 180-day response, each licensee and applicant shall confirm to the NRC that all the recommended actions or their justified alternatives have been implemented within 30 days of such implementation. This response need only be a single response to indicate that all initial tests or activities have been completed and that continuing programs have been established.

This request is covered by the Office of Management and Budget Clearance Number 3150-0011, which expires December 31, 1989. The estimated average burden is 1000 man-hours per addressee response, including assessing the actions to be taken, preparing the necessary plans, and preparing the 180-day response. This estimated average burden pertains only to these identified response-related matters and does not include the time for actual implementation of the recommended actions. Comments on the accuracy of this estimate and suggestions to reduce the burden may be directed to the Office of Management and Budget, Reports Management, Room 3208, New Executive Office Building, Washington, DC 20503 and to the U.S. Nuclear Regulatory Commission, Records and Reports Management Branch, Office of Information and Resources Management, Washington, DC 20555.

Although no specific request or requirement is intended, the following information would be helpful to the NRC in evaluating the cost of this Generic Letter:

1. Addressee time necessary to perform the requested confirmation and any needed follow-up actions.

2. Addressee time necessary to prepare the requested documentation. If there are any questions regarding this letter, please contact the regional administrator of the appropriate NRC regional office or your project manager in this office.

Sincerely,

James G. Partlow Associate Director for Projects Office of Nuclear Reactor Regulation

Enclosures:

1. "Recommended Program to Resolve Generic Issue 51"

2. "Program for Testing Heat Transfer Capability"

3. "Information Notices Related to Fouling Problems in Service Water Systems"

4. "Operating Experience Feedback Report - Service Water System Failures and Degradations in Light Water Reactors," NUREG-1275, Volume 3 5. List of Most Recently Issued Generic Letters

Appendix 9B
Enclosure 1

Recommended Program to Resolve Generic Issue 51

This enclosure describes a program acceptable to the NRC for meeting the objectives of the requested Action I in the proposed generic letter. Both Action I and this enclosure are based upon the recommendations described in "Technical Findings Document for Generic Issue 51: Improving the Reliability of Open-Cycle Service-Water Systems," NUREG/CR-5210, August 1988, and "Value/Impact Analysis for Generic Issue 51: Improving the Reliability of Open-Cycle Service-Water Systems," NUREG/CR-5234, February 1989. The NRC has concluded that Generic Issue 51 will be resolved when licensees and applicants implement either the recommended surveillance and control program addressed in this enclosure or an equally effective alternative course of action to satisfy the heat removal requirements of the service water system.

Water Source	Surveillance Techniques	Control Type Techniques
Marine or Estuarine (brackish) or Freshwater with clams	A	B and C
Freshwater without clams	A and D	B and C

A. The intake structure should be visually inspected, once per refueling cycle, for macroscopic biological fouling organisms (for example, blue mussels at marine plants, American oysters at estuarine plants, and Asiatic clams at freshwater plants), sediment, and corrosion. Inspections should be performed either by scuba divers or by dewatering the intake structure or by other comparable methods. Any fouling accumulations should be removed.

B. The service water system should be continuously (for example, during spawning) chlorinated (or equally effectively treated with another biocide) whenever the potential for a macroscopic biological fouling species exists (for example, blue mussels at marine plants, American oysters at estuarine plants, and Asiatic clams at freshwater plants). Chlorination or equally effective treatment is included for freshwater plants without clams because it can help prevent microbiologically influenced corrosion. However, the chlorination (or equally effective) treatment need not be as stringent for plants where the potential for macroscopic biological fouling species does not exist compared to those plants where it does. Precautions should be taken to obey Federal, State, and local environmental regulations regarding the use of biocides.

C. Redundant and infrequently used cooling loops should be flushed and flow tested periodically at the maximum design flow to ensure that they are not fouled or clogged. Other components in the service water system should be tested on a regular schedule to ensure that they are not fouled or clogged. Service water cooling loops should be filled with chlorinated or equivalently treated water before layup. Systems that use raw service water as a source, such as some fire protection systems, should also be chlorinated or equally effectively treated before layup to help prevent microbiologically influenced corrosion. Precautions should be taken to obey Federal, State, and local environmental regulations regarding the use of biocides.

D. Samples of water and substrate should be collected annually to determine if Asiatic clams have populated the water source. Water and substrate sampling is only necessary at freshwater plants that have not previously detected the presence of Asiatic clams in their source water bodies. If Asiatic clams are detected, utilities may discontinue this sampling activity if desired, and the chlorination (or equally effective) treatment program should be modified to be in agreement with paragraph B, above.

Appendix 9B
Enclosure 2

Program for Testing Heat Transfer Capability

This enclosure describes a program acceptable to the NRC for meeting the objectives of the requested Action II in the proposed generic letter. Both Action II and this enclosure are based in part on "Operating Experience Feedback Report - Service Water System Failures and Degradations," NUREG-1275, Volume 3, November 1988, and "Technical Findings Document for Generic Issue 51: Improving the Reliability of Open Cycle Service Water Systems," NUREG/CR-5210, August 1988. This enclosure reflects continuing operational problems, inspection reports, and industry standards ("Operation and Maintenance of Nuclear Power Plants," ASME/ANSI OM-1987, Part 2). The NRC requests licensees and applicants to implement either the steps addressed in this enclosure or an equally effective alternative course of action to satisfy the heat removal requirements of the service water system.

Both the initial test program and the periodic retest program should include all safety-related heat exchangers connected to or cooled by one or more open-cycle service water systems. A closed-cycle system is defined as a part of the service water system that is not subject to significant sources of contamination, one in which water chemistry is controlled, and one in which heat is not directly rejected to a heat sink. (The scope of closed cooling water systems is discussed in the industrial standard, "Operation and Maintenance of Nuclear Power Plants," ASME/ANSI OM-1987, Part 2.) If during the conduct of the total testing program any unexplained downward trend in heat exchanger performance is identified that cannot be remedied by maintenance of an open-cycle system, it may be necessary to selectively extend the test program to the attached closed-cycle system.

Testing should be done with necessary and sufficient instrumentation, though the instrumentation need not be permanently installed.

As a part of the initial test program, a licensee or applicant may decide to take corrective action before testing. Tests should be performed for the heat exchangers after the corrective actions are taken to establish baseline data for future monitoring of heat exchanger performance. In the periodic retest program, a licensee or applicant should determine after three tests the best frequency for testing to provide assurance that the equipment will perform the intended safety functions during the intervals between tests.

Therefore, in the periodic retest program, to assist that determination, tests should be performed for the heat exchangers before any corrective actions are taken. As in the initial test program, tests should be repeated after any corrective actions are taken to establish baseline data for future monitoring of heat exchanger performance.

An example of an alternative action that would be acceptable to the NRC is frequent regular maintenance of a heat exchanger in lieu of testing for degraded performance of the heat exchanger. This alternative might apply to small heat exchangers, such as lube oil coolers or pump bearing coolers or readily serviceable heat exchangers located in low radiation areas of the facility.

In implementing the continuing program for periodic retesting of safety-related heat exchangers cooled by service water in open-cycle systems, the initial frequency of testing should be at least once each fuel cycle, but after three tests, licensees and applicants should determine the best frequency for testing to provide assurance that the equipment will perform the intended safety functions during the intervals between tests and meet the requirements of GDC 44, 45, and 46. The minimum final testing frequency should be once every 5 years.

I. For all heat exchangers

Monitor and record cooling water flow and inlet and outlet temperatures for all affected heat exchangers during the modes of operation in which cooling water is flowing through the heat exchanger. For each measurement, verify that the cooling water temperatures and flows are within design limits for the conditions of the measurement. The test results from periodic testing should be trended to ensure that flow blockage or excessive fouling accumulation does not exist.

II. In addition to the considerations for all heat exchangers in Item I, for water-to-water heat exchangers

A. Perform functional testing with the heat exchanger operating, if practical, at its design heat removal rate to verify its capabilities. Temperature and flow compensation should be made in the calculations to adjust the results to the design conditions. Trend the results, as explained above, to monitor degradation. An example of this type of heat exchanger would be that used to cool a diesel generator. Engine jacket water flow and temperature and service water flow and temperature could be monitored and trended during the diesel generator surveillance testing.

B. If it is not practical to test the heat exchanger at the design heat removal rate, then trend test results for the heat exchanger efficiency or the overall heat transfer coefficient. Verify that heat removal would be adequate for the system operating with the most limiting combination of flow and temperature.

III. In addition to the considerations for all heat exchangers in Item I, for air-to-water heat exchangers

A. Perform efficiency testing (for example, in conjunction with surveillance testing) with the heat exchanger operating under the maximum heat load that can be obtained practically. Test results should be corrected for the off-design conditions. Design heat removal capacity should be verified. Results should be trended, as explained above, to identify any degraded equipment.

B. If it is not possible to test the heat exchanger to provide statistically significant results (for example, if error in the measurement exceeds the value of the parameter being measured), then

1. Trend test results for both the air and water flow rates in the heat exchanger.

2. Perform visual inspections, where possible, of both the air and water sides of the heat exchanger to ensure cleanliness of the heat exchanger.

IV. In addition to the considerations for all heat exchangers in Item I, for types of heat exchangers other than water-to-water or air-to-water heat exchangers (for example, penetration coolers, oil coolers, and motor coolers)

A. If plant conditions allow testing at design heat removal conditions, verify that the heat exchanger performs its intended functions. Trend the test results, as explained above, to monitor degradation.

B. If testing at design conditions is not possible, then provide for extrapolation of test data to design conditions. The heat exchanger efficiency or the overall heat transfer coefficient of the heat exchanger should be determined whenever possible. Where possible, provide for periodic visual inspection of the heat exchanger. Visual inspection of a heat exchanger that is an integral part of a larger component can be performed during the regularly scheduled disassembly of the larger component. For example, a motor cooler can be visually inspected when the motor disassembly and inspection are scheduled.

Appendix 9B
Enclosure 3

Information Notices Related to Fouling Problems in Service Water Systems

Information Notice No. 83-46: "Common-Mode Valve Failures Degrade Surry's Recirculation Spray Subsystem," July 11, 1983.

Information Notice No. 85-24: "Failures of Protective Coatings in Pipes and Heat Exchangers," March 26, 1985.

Information Notice No. 85-30: "Microbiologically Induced Corrosion of Containment Service Water System," April 19, 1985.

Information Notice No. 86-96: "Heat Exchanger Fouling Can Cause Inadequate Operability of Service Water Systems," November 20, 1986.

Information Notice No. 87-06: "Loss of Suction to Low Pressure Service Water System Pumps Resulting from Loss of Siphon," January 30, 1987.

Appendix 9C

Information Notices Related to Fouling Problems in Service Water Systems

Information Notice No. 83-46: "Common-Mode Valve Failures Degrade Surry's Recirculation Spray Subsystem," July 11, 1983.

Information Notice No. 85-24: "Failures of Protective Coatings in Pipes and Heat Exchangers," March 26, 1985.

Information Notice No. 85-30: "Microbiologically Induced Corrosion of Containment Service Water System," April 19, 1985.

Information Notice No. 86-96: "Heat Exchanger Fouling Can Cause Inadequate Operability of Service Water Systems," November 20, 1986.

Information Notice No. 87-06: "Loss of Suction to Low Pressure Service Water System Pumps Resulting from Loss of Siphon," January 30, 1987.

Information Notice No. 88-37: "Flow Blockage of Cooling Water to Safety System Components," June 14, 1988.

Information Notice No. 90-39: "Recent Problems with Service Water Systems," June 1, 1990.

Information Notice No. 92-49: "Recent Loss or Severe Degradation of Service Water Systems," July 2, 1992.

Information Notice No. 94-79: "Microbiologically Influenced Corrosion of Emergency Diesel Generator Service Water Piping," November 23, 1994.

10.0 Snubbers

Mechanical and hydraulic snubbers on safety-related piping systems and components provide a restraining function to reduce pipe and component stress and restrain excessive pipe and component movement under transient, faulted, and emergency conditions. Each snubber must accommodate a plant's normal thermal movements and be capable of restraining the maximum off-normal dynamic loads postulated for its specific location.

A Nuclear Plant Aging Research (NPAR) assessment of snubbers was conducted by Pacific Northwest Laboratory (Bush et al. 1986; Brown et al. 1990; Brown et al. 1992). This study provided the technical basis for the snubber standard technical specifications (STS) aging evaluation. Additional information was obtained from Blahnik et al. (1992).

10.1 Snubber Description

Approximately 66,000 snubbers are installed in U.S. nuclear power plants. Of these, approximately 15,000 are hydraulic piping snubbers, 50,000 are mechanical piping snubbers, and 1,200 are hydraulic equipment snubbers. Mechanical snubbers evaluated in the NPAR study were limited to the acceleration-limiting type that are manufactured by Pacific Scientific Company, which comprise approximately 95% of all mechanical snubbers in U.S. nuclear power plants. Hydraulic snubbers were limited to the lock-up/bleed-type that are manufactured by Grinnell Company and Bergen-Paterson Company, which comprise approximately 99% of the hydraulic snubbers in U.S. nuclear power plants. Examples of typical hydraulic and mechanical snubbers are shown in Figures 10.1 and 10.2, respectively.

10.2 Stressors, Aging Mechanisms, and Aging Effects

1. Hydraulic Snubbers

Hydraulic snubbers degrade in response to a number of stressors, including vibration, transient loads, moisture, heat, and radiation. Vibration causes wear and can generate solid particles that can affect control valve performance; severe vibration can result in gelation of the hydraulic fluid. Transient loads can cause severe structural damage to hydraulic snubbers. Moisture has caused internal corrosion problems in a limited number of cases involving snubbers with vented reservoirs.

The primary aging concern for hydraulic snubbers is degradation of elastomeric seals. The two most significant aging stressors associated with such seal degradation are heat and radiation. Seals used in hydraulic snubbers are manufactured from thermoplastics, metal, and elastomers (rubber). Thermoplastics are used in snubbers that are designed to remain in service without scheduled seal replacement. Although quite resistant to environmental degradation, thermoplastics have very little memory, requiring the use of internal springs to provide sealing force. Unlike elastomers, thermoplastics are unable to accommodate surface discontinuities and variations in part fit-up clearances. For this reason, surface-finish and tolerance requirements are much more stringent than for elastomers.

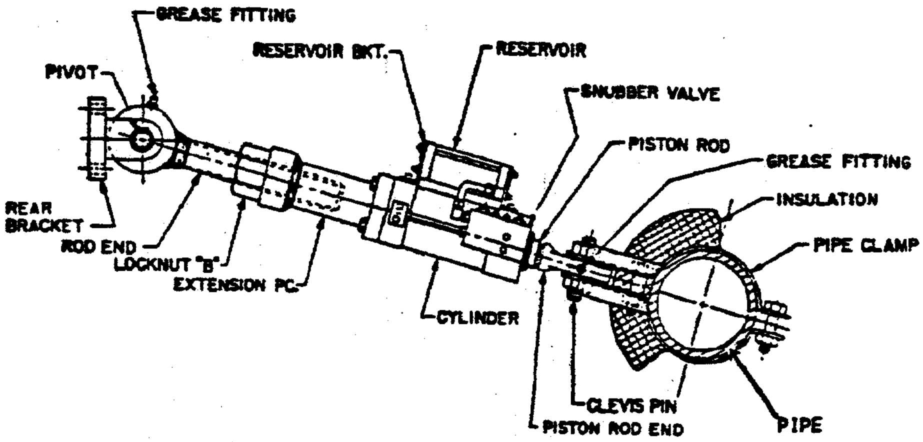

Figure 10.1. Typical Hydraulic Snubber

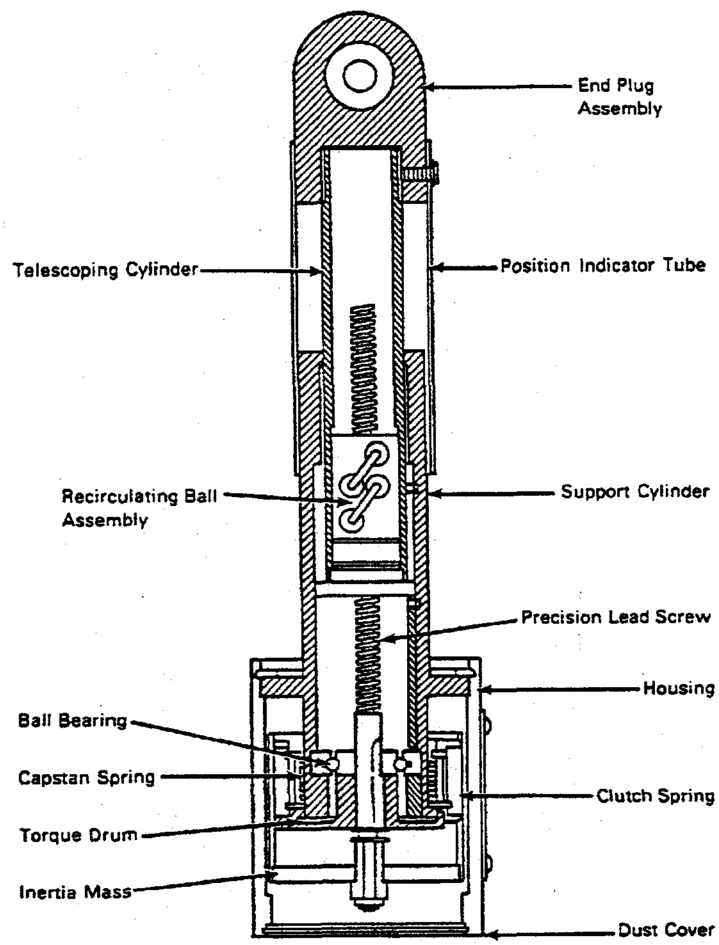

Figure 10.2. Typical Mechanical Snubber

As with thermoplastic seals, metallic seals require stringent machining and surface finish tolerances. Most metallic seals also require a soft plating to fill the gaps created by mating surface discontinuities. However, as with thermoplastic seals, once installed, there is a relatively low probability of degradation of sealing performance due to aging.

Elastomeric seals are the most commonly used seals in snubbers. In nuclear service, they are primarily provided in two basic rubber types. For the most part, the material of choice has been ethylene-propylene rubber, primarily due to its superior radiation resistance. Fluorocarbon rubber has a slightly lower resistance to radiation than ethylene-propylene rubber, but exhibits excellent temperature aging characteristics.

Elastomeric seals are subject to a number of service-related degradation problems, including extrusion, embrittlement, wear, fluid incompatibility, adhesion, and permanent set. Extrusion occurs when a seal flows through the gap formed between mating parts. Seal extrusion is not a common problem for hydraulic snubber seals; the limited number of these cases have been the result of design or assembly inadequacies.

Embrittlement is a potential failure mechanism for elastomeric seals that are exposed to elevated temperatures for prolonged periods. This is particularly true for seals that are exposed to air. Embrittlement can also occur due to fluid incompatibility.

In contrast to hydraulic cylinders that are used in most industrial applications, snubber seals rarely fail due to wear. However, solid particles generated by seal wear can affect snubber control valve performance. The limited amount of seal wear that has occurred in snubbers has generally been the result of excessive vibration.

Seals can also degrade due to incompatibility with the hydraulic fluid, resulting in volume changes and changes in durometer. Since the mid-1970s, however, there have been few instances of seal degradation due to fluid incompatibility.

2. Mechanical Snubbers

Mechanical snubbers, like their hydraulic counterparts, are subject to short-term degradation or failure due to excess heat, vibration, moisture, and load transients. There is also some indication of progressive (long-term) degradation in moderate operating environments.

A number of plants have reported degradation of mechanical snubber performance due to solidification of lubricants in high-temperature environments. In a scenario similar to that for seal materials, lubricants in mechanical snubbers were originally selected for their radiation resistance in lieu of alternative lubricants that are more heat resistant. For most applications, however, elevated temperature has proven to be a more prevalent stressor than radiation.

Component vibration is a significant cause of degradation for mechanical snubbers. High amplitude vibration can result in fretting and wear of mating internal and external parts. Such degradation often results in jamming, high drag force, and/or an increase in the snubber's mechanical clearances.

Low-amplitude, high-frequency vibration can cause many of the same problems as high-amplitude vibration and, in combination with the weight of the snubber, can cause significant wear of attachment pins and lugs. This type of vibration can also result in loosening of threaded fasteners.

Moisture can cause internal corrosion which, in turn, can lead to high drag force, jamming, or a decrease in the snubber's acceleration threshold. Corrosion has been a particular concern for snubbers installed vertically, whereby water may be trapped in the snubber.

Dynamic load transients are a common cause of mechanical snubber failure. This failure cause is particularly common for smaller load capacity snubbers, especially those that are installed on drain or instrumentation lines attached to larger piping. Two types of transient loadings are of concern: intermittent transient loading and severe overloading. In some cases, snubbers may be subject to intermittent transient loading in which the snubber is not rendered immediately inoperable. In this case, the snubber's ability to move freely may progressively degrade; the snubber may ultimately jam completely. This type of degradation is similar to degradation caused by high amplitude vibration, except that transient loading is not continuous. In other cases, snubbers may be subject to severe overloading as a result of a single dynamic transient, in which case, the snubber is rendered immediately inoperable. Failure, in such cases, is almost always in the form of total restriction of free motion (i.e., jamming). Some utilities have implemented requirements for handstroking snubbers suspected of having been subjected to transient loading to verify freedom of motion.

10.3 Degradation Detection Methods

Mechanical and hydraulic snubbers on safety-related piping systems and components provide a restraining function to reduce pipe and component stress and restrain excessive pipe and component movement under transient, faulted, and emergency conditions. The nature of this restraining function is such that it cannot be quantified by an operating parameter such as flow, pressure, level, etc. The only inherent parameters of the snubber system that can be measured under operating conditions are piping system vibration, snubber transient loads, and ambient temperatures. This type of monitoring, although helpful in determining operability with regards to snubber aging, is not cost effective on a major scale. However, limited monitoring in environments that are known to be severe, or where snubbers continually fail, is an option.

The effects of aging and the determination of "operability" can be accomplished by an in-depth snubber test and maintenance program, which is a maintenance activity. Handstroking of mechanical snubbers is an excellent method for identifying snubber degradation. Excessive resistance to motion and audible noises occurring when the snubber is stroked are indications of a potential problem. Jammed snubbers may often be detected by the snubber's inability to rotate around its end attachment bearings. Vibration or heat can sometimes be detected by placing a hand on snubbers that are accessible. Reinspection, just before start-up, of snubbers installed near outage-related activities will reduce the probability of plant operation with inoperable snubbers resulting from damage done by personnel.

10.4 Evaluation of Existing Surveillance Requirements for Effectiveness in Detecting Aging Degradation

There are no snubber-related surveillance requirements (SRs) in the Westinghouse plant STS.

10.5 Evaluation of Existing Surveillance Requirements for Possible Contributions to Premature Aging Degradation

There are no snubber-related SRs in the Westinghouse plant STS.

10.6 Recommendations to Improve or Supplement Surveillance Requirements

10.6.1 Recommendations from the NPAR Aging Assessments

The following service-life monitoring recommendations for mechanical and hydraulic snubbers resulted from the NPAR snubber aging studies:

1. It is essential that the snubber operating environment be identified. Specific parameters that should be monitored are: temperature, radiation, vibration, and dynamic load transients. Information about the environment can be obtained by visual examination of the snubbers (in situ and during installation), by evaluation of functional test data, by fluid sampling, and by conducting "hands-on" checks.

2. Root causes of failures should be determined. Determining the root cause of degradation in snubbers that are removed from service is also advisable. Data on degradation caused by nonservice-related influences should be interpreted separately from data that are used to verify service life.

3. Snubbers that are subjected to severe environmental influences should be identified and managed on a case-by-case basis.

4. Service life for the general snubber population should be established by trending relevant degradation parameters.

5. Augmented evaluation methods, such as handstroking, are useful to identify some forms of snubber degradation (i.e., degradation caused by dynamic load transients).

6. Service-life projections based on data from snubbers exposed to actual plant operating environments are preferable to analytical service-life projections.

7. Scheduled maintenance should be based on realistic expectations of service-related degradation. Unnecessary maintenance can increase the potential for snubber failure and result in unnecessary radiation exposure to personnel.

10.6.2 Implementing Suggested Recommendations

The effects of aging and the determination of "operability" can be accomplished by an in-depth snubber test and maintenance program, which is a maintenance activity. Such a snubber test program is required per Generic Letter 84-13, "Technical Specification for Snubbers," dated November 1984, and does not fall within the scope of the plant technical specifications to provide detailed directions or requirements.

Snubbers are also subject to the requirements of the *U.S. Code of Federal Regulations*, which specifies inspection and testing criteria. These criteria are contained in Section XI and Operations and Maintenance Standard, Part 4. The NPAR recommendations for improved service-life monitoring (Section 10.6.1) have been submitted for possible incorporation in the next revision of the ASME OM Code, Subsection ISTD.

It is concluded that snubbers are adequately addressed by present regulatory requirements and that no STS recommendations are needed.

11.0 Residual Heat Removal System

The Residual Heat Removal (RHR) system performs several safety functions during the various modes of Pressurized-Water Reactor (PWR) and Boiling-Water Reactor (BWR) operation. The primary function of the RHR system is to remove heat from the reactor core during normal shutdown, loss-of-coolant-accident (LOCA), and post-LOCA conditions. The RHR system may also assist in containment heat removal, containment spray operations, emergency reactor vessel level makeup, augmented fuel pool cooling, and refueling-water level control and transfer operations. The RHR system, also known among the different plant types as the low-pressure coolant injection system, the decay heat removal system, or the shutdown cooling system, thus plays a vital role in the safe operation of the plant during all modes of normal, accident, and post-accident operation.

A Nuclear Plant Aging Research (NPAR) assessment of RHR systems in BWRs was conducted by Brookhaven National Laboratory (Lofaro et al. 1989; Lofaro and Aggarwal 1992). This study provided the technical basis for the RHR standard technical specifications (STS) aging evaluation. Additional information was obtained from publications by Blahnik et al. (1992) and Jarrell et al. (1992).

11.1 Residual Heat Removal System Description and Boundaries

Residual Heat Removal systems are plant-specific. Generically, however, the RHR functions to transfer heat from three safety-related heat sources: core decay heat, decay heat removal components, and containment heat removal components. The following is a general description of the RHR system in PWRs and BWRs.

1. Pressurized-Water Reactor

The PWR RHR system (Figure 11.1) removes decay heat from the reactor core and sensible heat from the reactor coolant system to the component cooling water system. During normal plant operation, the RHR system is used to remove decay heat from the core and reduce the temperature of the reactor coolant to the cold shutdown temperature. During cold shutdown solid plant operations, the RHR system can be used in conjunction with the chemical and volume control system to maintain reactor coolant system chemistry and pressure control. The RHR system is also used to transfer water between the refueling water storage tank and the refueling cavity before and after refueling operations. In the event of a LOCA, the RHR system functions as the low-pressure coolant injection system to inject borated water into the reactor vessel for long-term emergency cooling.

2. Boiling-Water Reactor

Following a LOCA, the BWR RHR system (Figure 11.2) restores and maintains the prescribed water level in the reactor vessel and condenses steam and reduces airborne activity in the containment. The BWR RHR system also removes heat from the suppression pool, removes decay heat from the core following a reactor shutdown, condenses reactor steam, and returns the condensate back to the reactor vessel via the reactor core isolation cooling system. Other functions of the BWR RHR system are to provide fuel pool cooling if capacity beyond the normal system is required and flood the containment if required for long-term post-LOCA recovery operations.

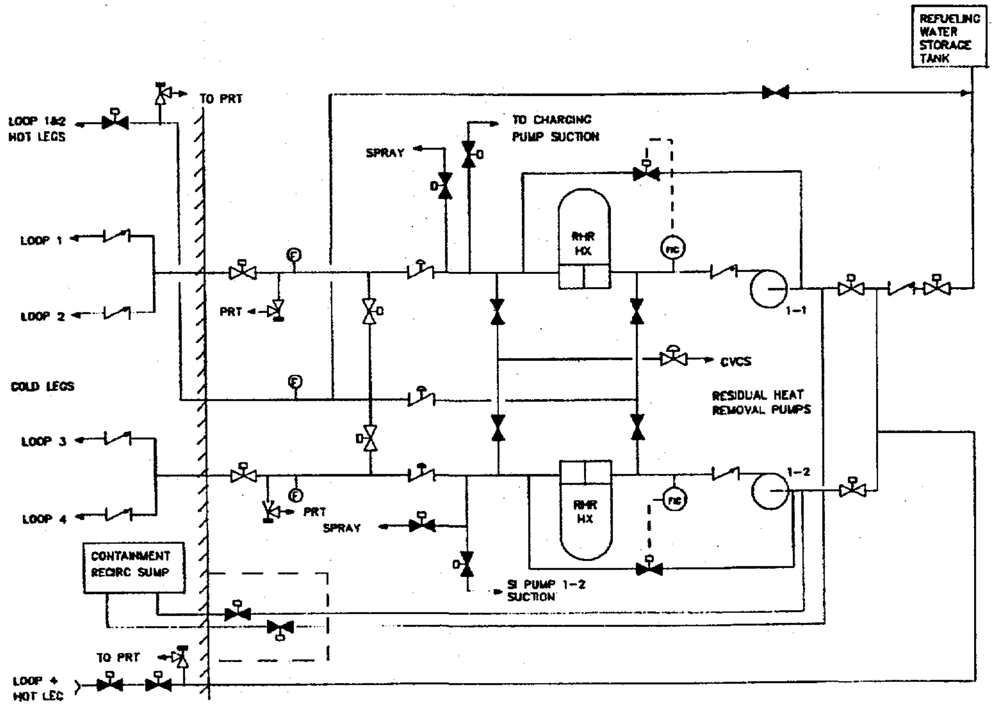

Figure 11.1. Typical RHR System for PWRs

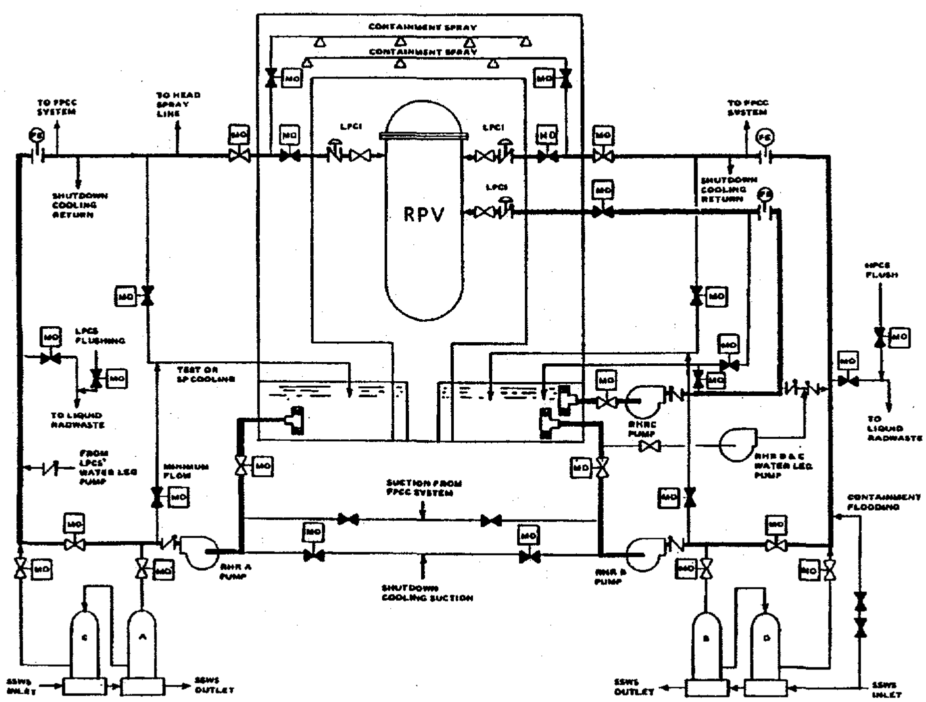

Figure 11.2. Typical RHR System for BWRs

For the normal shutdown cooling function, the RHR system pumps coolant from the reactor recirculation loop through the RHR system heat exchanger and then back into the reactor. For the low-pressure coolant injection function (which is automatically initiated by a LOCA), the RHR system pumps coolant from the suppression pool directly into the reactor without passing through the heat exchanger.

The RHR system includes the following active and passive components:

- RHR system pumps and motive sources, which include controls, cables/wires, and electrical distribution system

- the piping distribution network, from the RHR system pumps through the heat exchangers to the reactor coolant system injection and return legs. Interfaces include the fuel pool, refueling cavity, containment sprays and, if applicable, suppression pool and containment sumps. All valves, piping, heat exchangers, instrumentation, and logic networks are inclusive.

11.2 Stressors, Aging Mechanisms, and Aging Effects

Lofaro et al. (1989) was the only study found on aging of the RHR system; this study did not involve a detailed discussion of the aging of RHR subcomponents like that presented in previous sections of this report. Hence, Table 11.1 highlights specific problems of RHR aging that were found in Lofaro et al. 1989 and then references other tables in the report that discuss aging degradation that may be generally applicable to the RHR system. The following lists stressors, aging mechanisms, and resulting aging mechanisms that may apply to the RHR system components.

1. Pumps

- impellers are subject to wear, cavitation, and erosion

- casings are subject to erosion and cavitation

- bearings are subject to vibration, corrosion, wear, and lubrication degradation

- packing and seals are subject to overheating, thermal degradation, corrosion, erosion, and wear

- motors are subject to winding failures.

2. Valves

- bodies are subject to corrosion, erosion, and pitting

- seats are subject to corrosion and erosion

Table 11.1. Summary of Detection Capability of Current SRs

RHR Component	Known Stressors Contributing to Aging	Resulting Aging Mechanisms	Aging Degradation Effects	Recommended/ Suggested Degradation Detection Methods	Addressed by STS SRs?[a]
Pumps/Motors					
seals and packing	operation	wear, erosion	leakage	visual inspection	no
See Table 9.1	See Table 9.1	See Table 9.1	See Table 9.1	See Table 9.1	3.5.1.7, 3.5.1.10, 3.5.2.5, 3.5.2.6, 3.6.2.3.2, 3.6.2.4.2
Piping					
See Table 9.1	See Table 9.1	See Table 9.1	See Table 9.1	See Table 9.1	no
Valves					
check valves	See Table 5.2	See Table 5.2	See Table 5.2	See Table 5.2	no
isolation valves (including motor- and manually operated valves)	See Table 7.2	See Table 7.2	See Table 7.2	See Table 7.2	3.5.1.10, 3.5.2.6 (for automatic valve actuation on a simulated initiation signal)
Instrument & Controls					
See Table 9.1	See Table 9.1	See Table 9.1	See Table 9.1	See Table 9.1	3.5.1.10, 3.5.2.6
Heat Exchangers					
tubes	contaminants	fouling	blockage, wall-thinning, loss of mechanical strength	operation, high differential pressure, internal visual, ultrasonic examination, ET	no
See Table 9.1	See Table 9.1	See Table 9.1	See Table 9.1	See Table 9.1	no

(a) Representative SRs are listed where applicable.

- swing arms are subject to corrosion and fatigue
- stuffing boxes are subject to corrosion and wear
- discs/gates are subject to corrosion and erosion.

3. Heat Exchangers

- tubes are subject to corrosion, erosion, vibration, and distortion
- tubesheets are subject to corrosion
- waterboxes are subject to corrosion.

4. Piping

- walls are subject to erosion
- flanges and gaskets are subject to thermal fatigue, corrosion, erosion, and pitting.

5. Instruments and Controls

- switches are subject to cycling wear, thermal transients, humidity, corrosion, contamination, and vibration.

Also noted in Table 11.1 is whether or not a particular aging degradation effect is detected by the current surveillance requirements (SRs). Surveillance requirements from the General Electric BWR-4 STS are cited for those aging effects that are detectable. A potential deficiency in the STS is identified when a particular aging effect is not detected by any existing SR (i.e., the component may experience undetected degradation). A list of recommended SRs to address the undetected degradation in RHR systems is presented in Section 11.6.

11.3 Degradation Detection Methods

Several methods that are effective in detecting aging degradation have been developed, either historically or in response to specific aging concerns. The specific detection methods that are applicable to RHR system aging degradation are identified in Table 11.1 or in the other sections that are referenced by Table 11.1. Those methods that are useful and appropriate for inclusion in the SRs are identified in Section 11.6 as recommendations to improve and supplement the SRs.

11.4 Evaluation of Existing Surveillance Requirements for Effectiveness in Detecting Aging Degradation

The existing SRs for the RHR system focus primarily on operability concerns and not on addressing the detection and trending of aging degradation. For example, one SR requires that RHR pumps be demonstrated to start on an actuation signal; another requires that RHR automatic valves be demonstrated to align to their correct positions on an actuation signal; others require the measurement of plant conditions within the RHR system, such as water levels, developed differential pressure, and flows.

The parameters that are monitored and recorded during the American Society of Mechanical Engineers (ASME) Section XI testing do provide some data useful in identifying potential aging concerns. Twenty-seven percent of RHR failures are detected through operational abnormalities (i.e., during operation/testing). This indicates that some failures are not detected by current SRs until the component is required to operate. The data that are collected during the testing of RHR components could be augmented by additional information that would focus more on the detection and trending of aging degradation. The RHR-related SRs for the General Electric BWR-4 STS are summarized in Appendix 11A.

11.5 Evaluation of Existing Surveillance Requirements for Possible Contributions to Premature Aging Degradation

As noted in Section 11.4, existing SRs for the RHR system are designed primarily to determine operability and not to detect and trend aging degradation. Most SRs require verification of a condition or status, such as verifying valve position, which generally would have no aging impact. The few SRs that require demonstration or operation (i.e., in accordance with the ASME Section XI testing requirements) are on such a low frequency as to render their aging effects negligible. Thus, existing SRs for the RHR system do not contribute to aging in that the test methods and the frequency of testing do not cause premature aging degradation.

11.6 Recommendations to Improve or Supplement Surveillance Requirements

11.6.1 Recommendations from the NPAR Aging Assessments

Lofaro et al. (1989) surveyed nine BWR plants regarding the operational readiness of the RHR system. The survey suggested that since trending is an important tool for detecting aging degradation, the implementation of a trending program should be considered by all plants. The results of the survey indicated that the operational readiness of the RHR system could best be assured from three tests: valve stroke tests, control logic response tests, and in-service inspection pump tests. Lofaro et al. (1989) recommended that pump performance should be closely monitored and trended to identify performance degradation due to aging.

The RHR system valves fall under the recommendations made in Sections 5.0 and 7.0.

A systematic method for determining the root cause of a component failure was developed for the NPAR program (Jarrell et al. 1992). This methodology focuses resources on identifying and mitigating the underlying cause of failure rather than the treatment of an indicating symptom. It is recommended that a utility-specific version of this approach be incorporated into the SR framework.

11.6.2 Implementing Suggested Recommendations

A list of suggested SRs for RHR system components with associated surveillance frequencies to implement the recommendations from the NPAR aging assessments is provided in Table 11.2. Each of these generic SRs should be expanded by writing them for RHR system components throughout the STS in a form consistent with that of existing SRs, as identified in Appendix 11A.

These recommended SRs address the need for trending operational parameters that would detect age degradation and allow timely corrective action. Valve stroke tests, control logic response tests, and in-service inspection pump tests are already addressed in the STS.

Table 11.2. Surveillance Recommendations to Detect and Trend RHR System Aging Degradation

Surveillance Requirement	Frequency of Action
Trend pump parameters that include bearing temperature and vibration	7 days (during operation)
Trend parameters (i.e., pressure drop and temperature differential) that demonstrate the adequacy of the heat transfer capability of the heat exchangers	7 days (during operation)

Appendix 11A

Summary of RHR Surveillance Requirements from General Electric (BWR-4) STS

SR Number	Surveillance Requirement	Frequency	Detects Aging Degradation?
	RHR Shutdown Cooling - Hot Shutdown		
3.4.8.1	----------NOTE---------- Not required to be met until two hours after reactor steam dome pressure is < [the RHR cut in permissive pressure]. ------------------------ Verify one RHR shutdown cooling subsystem or recirculation pump is operating.	12 hours	no
	RHR Shutdown Cooling - Cold Shutdown		
3.4.9.1	Verify one RHR shutdown cooling subsystem or recirculation pump is operating.	12 hours	no
	Emergency Core Cooling Systems - Operating		
3.5.1.1	Verify, for each Emergency Core Cooling System injection/spray subsystem, the piping is filled with water from the pump discharge valve to the injection valve.	31 days	no
3.5.1.2	----------NOTE---------- Low pressure coolant injection subsystems may be considered OPERABLE during alignment and operation for decay heat removal with reactor steam dome pressure less than [RHR cut in permissive pressure] in MODE 3, if capable of being manually realigned and not otherwise inoperable. ------------------------ Verify each Emergency Core Cooling System injection/spray subsystem manual, power operated, and automatic valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days	no
3.5.1.4	Verify the [RHR] System cross tie valve[s] [is] closed and power is removed from the valve operator[s].	31 days	no
3.5.1.7	Verify the following Emergency Core Cooling System pumps develop the specified flow rate [against a system head corresponding to the specified reactor pressure]	In accordance with ISI testing program or 92 days	yes

SR Number	Surveillance Requirement	Frequency	Detects Aging Degradation?
3.5.1.10	---NOTE--- Vessel injection/spray may be excluded. --- Verify each Emergency Core Cooling System injection/spray subsystem actuates on an actual or simulated automatic initiation signal.	18 months	yes
	Emergency Core Cooling Systems - Shutdown		
3.5.2.1	Verify, for each required low pressure coolant injection subsystem, the suppression pool water level is ≥ [12 ft 2 inches].	12 hours	no
3.5.2.3	Verify, for each required Emergency Core Cooling System injection/ spray subsystem, the piping is filled with water from the pump discharge valve to the injection valve.	31 days	no
3.5.2.4	---NOTE--- One low-pressure coolant injection subsystem may be considered OPERABLE during alignment and operation for decay heat removal if capable of being manually realigned and not otherwise inoperable. --- Verify each required Emergency Core Cooling System injection/spray subsystem manual, power operated, and automatic valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days	no
3.5.2.5	Verify each required Emergency Core Cooling System pump develops the specified flow rate [against a system head corresponding to the specified reactor pressure].	In accordance with ISI testing or 92 days	yes
3.5.2.6	---NOTE--- Vessel injection/spray may be excluded. --- Verify each required Emergency Core Cooling System injection/spray subsystem actuates on an actual or simulated automatic initiation signal.	18 months	yes
	RHR Suppression Pool Cooling		
3.6.2.3.1	Verify each RHR suppression pool cooling subsystem manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position or can be aligned to the correct position.	31 days	no
3.6.2.3.2	Verify each RHR pump develops a flow rate > [7700] gpm through the associated heat exchanger while operating in the suppression pool cooling mode.	In accordance with ISI testing or 92 days	yes

SR Number	Surveillance Requirement	Frequency	Detects Aging Degradation?
	RHR Suppression Pool Spray		
3.6.2.4.1	Verify each RHR suppression pool spray subsystem manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position or can be aligned to the correct position.	31 days	no
3.6.2.4.2	Verify each RHR pump develops a flow rate ≥ [400] gpm through the heat exchanger while operating in the suppression pool spray mode.	In accordance with ISI testing or 92 days	yes
	Refueling Operations RHR-High Level		
3.9.8.1	Verify one RHR shutdown cooling subsystem is operating.	12 hours	no
	Refueling Operations RHR-Low Level		
3.9.9.1	Verify one RHR shutdown cooling subsystem is operating.	12 hours	no

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