UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

November 7, 2005

J. V. Parrish (Mail Drop 1023)
Chief Executive Officer
Energy Northwest
P.O. Box 968
Richland, WA 99352-0968

SUBJECT: COLUMBIA GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000397/2005004

Dear Mr. Parrish:

On September 23, 2005, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Columbia Generating Station. The enclosed inspection report documents the inspection findings which were discussed on September 26, 2005, with Mr. Dale Atkinson and other members of your staff.

The inspections examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This report documents one NRC-identified finding and one self-revealing finding of very low risk significance. One of these findings was determined to involve a violation of NRC requirements. However, because of the very low safety significance and because it is entered into your corrective action program, the NRC is treating this finding as a noncited violation consistent with Section VI.A.1 of the NRC Enforcement Policy. If you contest these findings, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011-4005; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident inspector at the Columbia Generating Station.

This report also documents the closure of an unresolved item associated with the NRC's review of your staff's reclassification of two licensee event reports. These event reports were associated with two loss of shutdown cooling events which occurred during a refueling outage in 2003. Both events were originally reported by your staff as events that could have prevented the fulfillment of the safety function of a system needed to remove residual heat in accordance with 10 CFR 50.73(a)(2)(v)(B) and as an input to the NRC Safety System Functional Failure Performance Indicator. Subsequent to the submittal of this information, your staff reevaluated the characterization of both events and concluded that the events were not reportable in accordance with 50.73(a)(2)(v)(B). Your staff then revised the basis for both event reports as "voluntary." As a result, your staff revised the reported data for the Safety System Functional Failure Performance Indicator.

The NRC concluded that your staff misinterpreted the requirements of 10 CFR 50.73(a)(2)(v)(B) and the guidance provided in NUREG-1022, "Event Reporting Guidelines 10 CFR 50.72 and 50.73," Revision 2, when these two loss of shutdown cooling events were determined by your staff to not be reportable in accordance with 10 CFR 50.73(a)(2)(v)(B). By revising the performance indicator data, the Safety System Functional Failure Performance Indicator data was reported as "Green" for the 2nd quarter of 2004 when it should have been reported as "White". The basis for this conclusion is documented in Section 4OA5.2 of the report. Accordingly, the NRC plans to conduct Supplemental Inspection 95001, "Inspection For One Or Two White Inputs In A Strategic Performance Area," at Columbia Generating Station for the "White" 2nd quarter 2004 Safety System Functional Failure Performance Indicator consistent with Manual Chapter 0305, "Operating Reactor Assessment Program," Section 6.05.b which describes the NRC's response for performance in each Action Matrix column.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Should you have any questions concerning this inspection, we will be pleased to discuss them with you.

Sincerely,

/RA/

Claude E. Johnson, Chief
Project Branch A
Division of Reactor Projects

Docket: 50-397
License: NPF-21

Enclosure:
NRC Inspection Report
05000397/2005004

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SISP Review Completed: CEJ ADAMS: / Yes ☐ No Initials: CEJ
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ZKDunham	RBCohen	TRFarnholtz	CEJohnson	ATHowell
E-TRFarnholtz	E-TRFarnholtz	/RA/	/RA/	/RA/
10/27/05	10/27/05	10/25/05	11/07/05	10/31/05

AC:DRS/EB1	C:DRS/PSB	C:DRS/EB2	C:DRS/OB	
CJPaulk	MPShannon	LJSmith	ATGody	
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10/25/05	10/29/05	10/26/05	10/27/05	

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	50-397
License:	NPF-21
Report:	05000397/2005004
Licensee:	Energy Northwest
Facility:	Columbia Generating Station
Location:	Richland, Washington
Dates:	June 24, 2005 through September 23, 2005
Inspectors:	Z. Dunham, Senior Resident Inspector, Project Branch A, DRP R. Cohen, Resident Inspector, Project Branch A, DRP G. Pick, Reactor Inspector, Plant Support Branch B. Baca, Health Physicist, Plant Support Branch G. Guerra, Health Physicist, Plant Support Branch T. Jackson, Senior Resident Inspector, Project Branch B, DRP P. Elkmann, Emergency Preparedness Inspector, Operations Branch J. Keeton, Reactor Inspector, NRC Contractor
Approved By:	C. E. Johnson, Chief, Project Branch A, Division of Reactor Projects
ATTACHMENT:	Supplemental Information

CONTENTS

SUMMARY OF FINDINGS

IR05000397/2005004; 6/24/2005 - 9/23/2005; Columbia Generating Station; Post Maintenance Testing, Other Activities.

The report covered a 13-week period of inspection by resident inspectors, health physicist inspectors, and reactor inspectors. Two Green findings were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or, Red) using Inspection Manual Chapter 0609, “Significance Determination Process.” Findings for which the significance determination process does not apply may be Green or be assigned a severity level after NRC management review. The NRC’s program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, “Reactor Oversight Process,” Revision 3, dated July 2000.

A. NRC Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. A self-revealing finding associated with electricians’ failure to follow a maintenance procedure was identified following the discovery of an oil leak on the startup transformer. The oil leak occurred due to a damaged lead which had been incorrectly terminated during the maintenance activity. The finding had crosscutting aspects in the area of human performance because the electricians’ failed to follow a maintenance procedure.

  This finding was greater than minor because it was a human error which affected the mitigating system cornerstone objective to ensure the availability of systems that respond to initiating events. The finding was determined to be of very low safety significance because there was no actual loss of safety function, the finding was not a design qualification issue, and the finding was not potentially risk significant due to external events. No violation of NRC requirements was identified. (Section 1R19)

- Green. The inspectors identified a noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI (Corrective Actions), with two examples, because the licensee failed to promptly identify and correct conditions adverse to quality associated with seismically nonconforming 480 VAC and 4160 VAC breakers. For the first example, the licensee failed to identify dis-engaged restraint latches on 9 breakers in Motor Control Center (MCC) E-MC-4A, despite earlier, but narrowly focused, inspections for seismic issues. In the second example, the licensee missed several opportunities to identify that the front wheels of several safety-related 4160 VAC breakers did not touch the floor due to breaker-cubicle fit-up problems. These issues had crosscutting aspects in the area of problem identification because the licensee failed to promptly identify and correct seismically nonconforming breakers following a reasonable opportunity to do so.

The findings were more than minor because they impacted the Mitigating Systems Cornerstone objective of availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using the Phase 1 Significance Determination Process Screening Worksheet in Inspection Manual Chapter 0609, Appendix A, the findings were of very low risk significance because they constituted design/qualification deficiencies that did not result in a loss of function per Generic Letter 91-18, "Information to Licensees Regarding NRC Inspection Manual Section on Resolution of Degraded and Nonconforming Conditions," Revision 1. (Section 4OA5.1)

B. Licensee Identified Violations

Two violations of very low significance were identified by the licensee and reviewed by the inspectors. Corrective actions taken or planned by the licensee appeared reasonable. These violations are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status:

The inspection period began with Columbia Generating Station shutdown in forced outage F-5-02 following an automatic reactor scram on June 23, 2005, from approximately 24 percent power. The licensee commenced a reactor startup on June 30, 2005, and returned to full power on July 3. The licensee operated the facility at full power for the remainder of the inspection period except for brief reductions in power to facilitate plant maintenance and testing.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

The inspectors completed a review of the licensee’s readiness of seasonal susceptibilities involving damage from high winds or a tornado strike. The inspectors: (1) reviewed plant procedures, the Updated Safety Analysis Report, and Technical Specifications to ensure that operator actions defined in adverse weather procedures maintained readiness of essential systems; (2) walked down portions of the below listed area/system to ensure that system design and protective measures for protection against missile hazards were sufficient to support operability, including the ability to perform safe shutdown functions; (3) evaluated operator staffing levels to ensure the licensee could maintain the readiness of essential systems required by plant procedures; and (4) reviewed the corrective action program to determine if the licensee identified and corrected problems related to adverse weather conditions.

- Transformer Yard (Startup and Backup Transformers); August 2005

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignments (71111.04)

.1 Partial Walkdown

a. Inspection Scope

The inspectors: (1) walked down portions of the three risk important systems listed below and reviewed plant procedures and documents to verify that critical portions of the selected systems were correctly aligned; and (2) compared deficiencies identified during the walk down to the licensee's corrective action program to ensure problems were being identified and corrected.

- Reactor Core Isolation Cooling System; July 1, 2005
- Emergency Diesel Generator - Division 2; August 10, 2005
- Residual Heat Removal - Train A; September 7, 2005

The inspectors completed three samples.

b. Findings

No findings of significance were identified.

.2 Complete Walkdown

The inspectors: (1) reviewed plant procedures, drawings, the Updated Safety Analysis Report, Technical Specifications, and vendor manuals to determine the correct alignment of the system; (2) reviewed outstanding design issues, operator work arounds, and corrective action program documents to determine if open issues affected the functionality of the system; and (3) verified that the licensee was identifying and resolving equipment alignment problems.

- Division I Emergency Diesel Generator; September 6, 2005

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Quarterly Inspection

a. Inspection Scope

The inspectors walked down six plant areas listed below to assess the material condition of active and passive fire protection features and their operational lineup and readiness. The inspectors: (1) verified when applicable that transient combustibles and hot work activities were controlled in accordance with plant procedures; (2) observed the condition of fire detection devices to verify they remained functional; (3) observed fire suppression systems to verify they remained functional; (4) verified that fire extinguishers and hose stations were provided at their designated locations and that they were in a satisfactory condition; (5) verified that passive fire protection features (electrical raceway barriers, fire doors, fire dampers, steel fire proofing, penetration seals, and oil collection systems) were in a satisfactory material condition; (6) verified when applicable that adequate compensatory measures were established for degraded or inoperable fire protection features; and (7) reviewed the corrective action program to determine if the licensee identified and corrected fire protection problems.

- Fire Area RC-2; Cable Spreading Room - Corridor C304, Rad Waste Building 487' level; August 17, 2005
- Main Transformer Yard; Transformers E-TR-B and E-TR-S; September 16, 2005
- Fire Area R-1/1; Standby Gas Treatment Area; September 17, 2005
- Fire Area RC-3/1; Vertical Cable Chase; September 18, 2005
- Fire Area RC-11/1; HVAC Equipment Room “A” Div 1; September 18, 2005
- Fire Area RC-12/2; HVAC Equipment Room “B” Div 2; September 18, 2005

The inspectors completed six samples.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

.1 Annual External Flood Protection

a. Inspection Scope

The inspectors reviewed the Columbia Generating Station Final Safety Analysis Report (FSAR), Technical Specifications, and corrective action database to identify any external flood threats to the facility. Final Safety Analysis Report Sections 2.4.2 and 3.4.1.5.1, document that there are no external flood threats, either from ground water, local precipitation, or from the nearby Columbia River. The inspectors toured the external areas for any credible flood sources.

b. Findings

No findings of significance were identified.

.2 Internal Flood Protection

a. Inspection Scope

The inspectors performed the following: (1) reviewed the Updated Safety Analysis Report, the flooding analysis, and plant procedures to assess seasonal susceptibilities involving internal flooding; (2) reviewed the corrective action program to determine if the licensee identified and corrected flooding problems; (3) inspected underground bunkers/manholes to verify the adequacy of (a) sump pumps, (b) level alarm circuits, ©) cable splices subject to submergence, and (d) drainage for bunkers/manholes; (4) verified that operator actions for coping with flooding can reasonably achieve the desired outcomes; and (5) walked down the areas listed below to verify the adequacy of: (a) equipment seals located below the floodline, (b) floor and wall penetration seals, ©) watertight door seals, (d) common drain lines and sumps, (e) sump pumps, level alarms, and control circuits, and (f) temporary or removable flood barriers.

- Standby Service Water Pumphouse 1B; September 19, 2005
- 4160 VAC Switchgear Rooms; September 19, 2005

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance

.1 Biennial Heat Sink Performance (71111.07B)

a. Inspection Scope

The inspectors reviewed design documents (e.g., calculations and performance specifications), program documents, implementing documents (e.g., test and maintenance procedures), and corrective action documents. The inspectors interviewed chemistry personnel, maintenance personnel, engineers, and program managers.

The inspectors verified for heat exchangers directly connected to the safety-related service water system, whether testing, inspection and maintenance, or the biotic fouling monitoring program provided sufficient controls to ensure proper heat transfer. Specifically, the inspectors reviewed: (1) heat exchanger test methods and test results from performance testing, (2) if necessary, heat exchanger inspection and cleaning methods and results, and (3) chemical treatments for microfouling and controls for macrofouling.

The inspectors verified for heat exchangers directly or indirectly connected to the safety-related service water system the following: (1) condition and operation consistent with design assumptions in the heat transfer calculations, (2) potential for water hammer, as applicable, (3) vibration monitoring controls for the heat exchangers, (4) chemistry controls for heat exchangers indirectly connected to the safety-related service water system, and (5) redundant and infrequently used heat exchangers are flow tested periodically at maximum design flow.

The inspectors also evaluated for the ultimate heat sink and its subcomponents, the following requirements: (1) capacity of the reservoir, (2) macrofouling controls, (3) biotic fouling controls, and (4) performance tests for pumps and valves.

If available, the inspectors reviewed additional nondestructive examination results for the selected heat exchangers that demonstrated structural integrity.

The inspectors selected heat exchangers that ranked high in the plant specific risk assessment and were directly or indirectly connected to the safety-related service water system. The inspectors selected the following specific heat exchangers:

- Residual Heat Removal Heat Exchanger Train A
- Diesel Generator Train B Heat Exchangers
- Standby Service Water Train A Pump House Room Cooler

The inspectors completed three samples.

b. Findings

No findings of significance were identified.

.2 Annual Heat Sink Performance (71111.07)

a. Inspection Scope

The inspectors observed performance tests, reviewed test data from performance tests, or verified the licensee's execution and on-line monitoring of bio-fouling controls where applicable for the system listed below. The inspectors verified that: (1) test acceptance criteria and results considered differences between testing and design conditions; (2) inspection results were appropriately categorized against acceptable pre-established acceptance criteria; (3) the frequency of testing or inspection was sufficient to detect degradation prior to the loss of the heat removal function; (4) the test results considered instrument uncertainties; and (5) the licensee had established bio-fouling controls.

- Reactor Closed Loop Cooling Heat Exchangers; August 25, 2005

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

On August 22, 2005, the inspectors observed testing and training of senior reactor operators and reactor operators to identify deficiencies and discrepancies in the training, to assess operator performance, and to assess the evaluator's critique. The training scenario involved a loss of off-site power resulting in a loss of all high pressure feed to the reactor and a small loss of coolant accident from reactor recirculation Loop ‘B’.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed the maintenance activity listed below to: (1) verify the appropriate handling of structure, system, and component (SSC) performance or condition problems; (2) verify the appropriate handling of degraded SSC functional performance; (3) evaluate the role of work practices and common cause problems; and (4) evaluate the handling of SSC issues reviewed under the requirements of the maintenance rule, 10 CFR 50 Appendix B, and the Technical Specifications.

- Reactor Protection System Motor Generator Loss; July 26, 2005

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

.1 Risk Assessment and Management of Risk

a. Inspection Scope

The inspectors reviewed the three assessment activities listed below to verify: (1) performance of risk assessments when required by 10 CFR 50.65 (a)(4) and licensee procedures prior to changes in plant configuration for maintenance activities and plant operations; (2) the accuracy, adequacy, and completeness of the information considered in the risk assessment; (3) that the licensee recognizes, and/or enters as applicable, the appropriate licensee-established risk category according to the risk assessment results and licensee procedures, and (4) the licensee identified and corrected problems related to maintenance risk assessments.

- Diesel Generator Division 1 scheduled maintenance outage coincident with control room emergency filtration train A maintenance; August 8, 2005
- Repair work on the Startup Transformer with the 500 kV back feed through the main transformer; August 31, 2005
- High pressure core spray pump Switchgear SM-4 and the Division 3 Diesel Generator scheduled preventive maintenance outage; September 12 - 16, 2005

The inspectors completed three samples.

b. Findings

No findings of significance were identified.

.2 Emergent Work Control

a. Inspection Scope

The inspectors verified: (1) that the licensee performed actions to minimize the probability of initiating events and maintained the functional capability of mitigating systems and barrier integrity systems; (2) that emergent work-related activities such as troubleshooting, work planning/scheduling, establishing plant conditions, aligning equipment, tagging, temporary modifications, and equipment restoration did not place the plant in an unacceptable configuration; and (3) reviewed the corrective action program to determine if the licensee identified and corrected Risk Assessment and Emergent Work Control problems.

- 125 VDC Battery E-B1-2 (Division 2) individual cell number 48 below Category A/B limits and subsequent replacement coincident with High Pressure Core Spray Outage; July 22, 2005

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Nonroutine Plant Evolutions and Events (71111.14)

I. Inspection Scope

The inspectors: (1) reviewed operator logs, plant computer data, and/or strip charts for the evolutions listed below to evaluate operator performance in coping with non-routine events and transients; (2) verified that the operator response was in accordance with the response required by plant procedures and training; (3) verified that the licensee has identified and implemented appropriate corrective actions associated with personnel performance problems that occurred during the non-routine evolutions sampled.

- Reactor Startup following forced outage F-05-02; June 30, 2005
- Feedwater Heat Exchanger 2C High Level Trip; August 9, 2005

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors: (1) reviewed plants status documents such as operator shift logs, emergent work documentation, deferred modifications, and standing orders to determine if an operability evaluation was warranted for degraded components; (2) referred to the Updated Safety Analysis Report and design basis documents to review the technical adequacy of licensee operability evaluations; (3) evaluated compensatory measures associated with operability evaluations; (4) determined degraded component impact on any Technical Specifications; (5) used the Significance Determination Process to evaluate the risk significance of degraded or inoperable equipment; and (6) verified that the licensee has identified and implemented appropriate corrective actions associated with degraded components.

- CR 2-05-06556, DG-GEN-DG2 oil leak under heat exchanger for engine 1B2; August 18, 2005

- CR 2-05-06806, Control Rod Drive System Inoperative; September 14, 2005

- CR 2-05-05566; SW-FI-602A indicates approximately 2000 gpm with SW-P-1A off; July 6, 2005

- CR 2-05-05739; Suspected seat leakage past MS-V-20; July 12, 2005

- CR 2-05-06087; RHR-42-8BA/5D (the electrical disconnect for RHR-V-27B) overloads tripped during valve closure; August 5, 2005

The inspectors completed five samples.

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

a. Inspection Scope

The inspectors reviewed the circumstances associated with the equipment deficiency listed below to determine if the issue met the criteria for being an operator workaround. The inspectors also reviewed Energy Northwest's Operator Burden Log to determine if any other risk significant operator workaround samples were available for review. The following attributes were considered: (1) determine if the functional capability of the system or human reliability in responding to an initiating event is affected; (2) evaluate the effect of the operator workaround on the operator's ability to implement abnormal or emergency operating procedures; and (3) verify that the licensee has identified and implemented appropriate corrective actions associated with operator workarounds.

- CR 2-05-07177; High pressure core spray valve, HPCS-V-12, failed postmaintenance and operability testing resulting in Energy Northwest opening the supply breakers for HPCS-V-12 and HPCS-V-4 to comply with Technical Specification Action Statement 3.6.1.3.a; September 19, 2005

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope

The inspectors reviewed key affected parameters associated with energy needs, materials/replacement components, timing, heat removal, control signals, equipment protection from hazards, operations, flowpaths, pressure boundary, ventilation boundary, structural, process medium properties, licensing basis, and failure modes for the two modifications listed below. The inspectors verified when applicable that: (1) modification preparation, staging, and implementation does not impair emergency/abnormal operating procedure actions, key safety functions, or operator response to loss of key safety functions; (2) post-modification testing will maintain the plant in a safe configuration during testing by verifying that unintended system interactions will not occur, SSC performance characteristics still meet the design basis, the appropriateness of modification design assumptions, and the modification test acceptance criteria has been met; and (3) the licensee has identified and implemented appropriate corrective actions associated with permanent plant modifications.

- Basic Design Change (BDC) 394; Reactor Core Isolation Cooling (RCIC) Water Hammer Prevention System Upgrades; Implemented 2001; Reviewed July 2005
- Minor Plant Design Change MPDC 4073-06; RCIC time delay relay installation for the RCIC pump suction; Implemented June 29, 2005; Reviewed August 2005

The inspectors completed two samples.

b. Findings

Introduction. An unresolved item was identified pending the NRC's determination of the regulatory aspects and evaluation of the safety significance of a failure of the RCIC system to start when operators attempted to start the system following a scram on June 23, 2005.

Description. Energy Northwest determined that RCIC pump, RCIC-P-1, turbine tripped due to a momentary decrease in pressure in the RCIC system suction header following a scram on June 23, 2005. The momentary pressure decrease occurred as a result of a hydraulic pressure wave which resulted when RCIC pump discharge pressure overcame the differential pressure required to open a downstream injection check valve. The hydraulic pressure wave caused a momentary pressure decrease in the suction header of RCIC-P-1. The RCIC turbine steam admission valve, RCIC-V-1, automatically closed per design when suction header pressure momentarily decreased below 15" Hg Vacuum as sensed by a pressure switch located on the suction header of the RCIC pump. The RCIC pump is designed to trip on low suction pressure to ensure that sufficient net positive suction head is available to the pump to ensure operability.

The inspectors noted the following potential issue:

BDC 394, implemented on June 18, 2001, changed the operating characteristics of the RCIC keepfill pump, RCIC-P-3. RCIC-P-3 is a non-safety related and not credited in the facility safety analysis. Prior to the implementation of BDC 394, RCIC-P-3 operated continuously which maintained the discharge line and suction header pressurized to approximately 80 psig whenever RCIC-P-1 was stopped. Although not known by Energy Northwest at the time that BDC 394 was implemented, continuously running RCIC-P-3 helped historically to ensure that a momentary pressure transient during a start of RCIC-P-1 would not cause a low suction pressure trip of RCIC-P-1.

BDC 394 changed the RCIC-P-3 control logic to start RCIC-P-3 at 68 psig as sensed from a pressure sensor located downstream of the RCIC-P-1 discharge checkvalve.

The change was made to minimize the run time of RCIC-P-3 to extend it's operating life. However, changing the control logic of RCIC-P-3 to run on demand resulted in unintended low suction pressure conditions. These conditions were conducive to RCIC-P-1 inadvertently tripping on low suction pressure when a pump start pressure transient occurred. For example, lower suction pressures which were experienced after initial operation of the RCIC system following a plant scram on June 23, 2005, resulted in two inadvertent trips of RCIC. Additionally, lower suction header pressure conditions periodically occurred following plant startups when RCIC was required to be operable. In these conditions following a plant startup, RCIC-P-1 was susceptible to an inadvertent low suction pressure trip upon initial operation in response to an event.

FSAR, Section 5.4.6, "Reactor Core Isolation Cooling System," Amendment 56, described that the RCIC system was designed to initiate automatically upon reaching a predetermined low level in the reactor vessel and to restart automatically with no operator action after a reactor vessel level 8 shutdown of RCIC-P-1. The inspectors also noted that technical specification surveillance requirement basis 3.5.3.5 required that the RCIC system actuate automatically to perform its design function. The inspectors reviewed Safety Evaluation SE-00-0068, Revision 0, which evaluated BDC 394 as required by 10 CFR 50.59 to determine the adequacy of the safety evaluation. Energy Northwest concluded that the proposed activity did not increase the probability of occurrence of a malfunction of equipment important to safety as previously evaluated in the final safety analysis report. Energy Northwest also stated in SE-00-0068 that the addition of a checkvalve in BDC 394, the elevation head of the condensate storage tanks or suppression pool, and the auto-inhibit feature of pressure switch RCIC-PIS-1 eliminated the system's reliance on keepfill during automatic operation. The inspectors determined Energy Northwest's conclusion that the keepfill system was not needed to ensure automatic operation of the RCIC system was incorrect.

During a review of the issue, Energy Northwest concluded that the dependency of the RCIC system on RCIC-P-3 operation to ensure that the RCIC system would successfully perform it's safety function to automatically start was a latent design issue which had been present since initial operation of the facility. Since RCIC-P-3 is not credited in the safety analysis and not safety-related, accident analysis could not take credit for operation of RCIC-P-3 to ensure the successful operation of the RCIC system. Any failure of RCIC-P-3, either before or after the implementation of BDC 394, would have impacted the ability of the RCIC system to automatically start and perform it's safety function.

An Unresolved Item (URI) (URI 50-397/05-04-01, Adequacy of Design of the Reactor Core Isolation Cooling System and the Keepfill Pump) was opened for further NRC review of regulatory impact of any potential performance issues and final evaluation of the safety significance. Energy Northwest took immediate corrective actions to implement a design change to install a time delay relay on the low suction pressure trip circuitry of the RCIC system to ensure that momentary pressure transients which occur during a RCIC pump start do not cause an inadvertent trip of RCIC-P-1. Energy Northwest documented the issue in their corrective action program in PER 205-0429 and planned an additional corrective action to benchmark other plants to evaluate how Energy Northwest operates the RCIC system to ensure consistent operation as compared to the rest of the industry.

Analysis. The issue associated with RCIC-P-3 and its impact on RCIC system performance is under review by NRC staff. A determination of the safety significance of any performance deficiencies will be addressed in the resolution of the URI.

Enforcement. Pending further review by the NRC staff, this item remains unresolved.

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors selected the seven post maintenance test activities listed below for review. For each item, the inspectors: (1) reviewed the applicable licensing basis and/or design-basis documents to determine the safety functions; (2) evaluated the safety functions that may have been affected by the maintenance activity; and (3) reviewed the test procedure to ensure it adequately tested the safety function that may have been affected. The inspectors either witnessed or reviewed test data to verify that acceptance criteria were met, plant impacts were evaluated, test equipment was calibrated, procedures were followed, jumpers were properly controlled, the test data results were complete and accurate, the test equipment was removed, the system was properly re-aligned, and deficiencies during testing were documented. The inspectors also reviewed the corrective action program to determine if the licensee identified and corrected problems related to post maintenance testing.

- WO 01093410 HPCS-V-10 Inspect Disconnect; July 18 and 22, 2005
- WO 01104698; Rod Drive Control System Branch Junction Module Transponder Replacement; September 1, 2005
- WO 01081617; E-CB-B/7 Truck Operated Cell Rod Replacement; August 11, 2005
- WO 01093021; Standby Liquid Control Pump 1A Test and Inspection; August 2, 2005
- WO 01102092; Battery E-B1-1 Cell 48 Replacement; July 22, 2005
- WO 01098390; RFW-V-65A Electrical Backseat; July 8, 2005
- **WO 01063246; E-TR-S Replace Wiring; May 26, 2005**

The inspectors completed seven samples.

b. Findings

Introduction. A Green self-revealing finding associated with maintenance technicians' failure to follow a maintenance work order instruction resulted in the incorrect termination of a current transformer lead and subsequent oil leak on the Startup Transformer (E-TR-S). A crosscutting aspect of human performance was identified because the technicians performing the task failed to follow the work order instruction and adequately self-check to ensure that the lead was terminated properly.

Description. During refueling outage 17, Energy Northwest replaced the leads for the current transformers on E-TR-S. On May 26, 2005, during post maintenance testing associated with the replacement of the leads, technicians lifted each wire to the current transformer to perform continuity checks. After the continuity checks were complete, the wires were sequentially re-landed and torqued to their respective terminals. On May 27, 2005, startup Transformer E-TR-S was energized following the planned maintenance and declared operable. Subsequently, on June 22, 2005, an oil leak on the startup transformer was identified by Energy Northwest. An subsequent investigation during a forced outage determined that one of the leads from one of the current transformers was burnt. The burnt lead caused a hole to develop in adjacent transformer insulation resulting in the oil leak. It was later determined that a lead associated with the post maintenance testing that occurred on startup Transformer E-TR-S on May 26, 2005, had not been terminated in accordance with the work order instructions and an associated system drawing. Specifically, one wire that was removed from the X1 terminal on the current transformer, was replaced on a different terminal counter-clockwise and adjacent to where it was removed. This adjacent terminal had no identifying marking. Although an oil leak developed as a result of the incorrectly terminated lead, the oil leak was not sufficient to impact operability of startup Transformer E-TR-S.

Analysis. The performance deficiency associated with this finding was Energy Northwest's failure to properly terminate the X1 lead from the startup Transformer E-TR-S in accordance with WO 01063246, Task 3. This finding is greater than minor because it matched example 5.b of the minor examples provided in MC 0612, Appendix E, in that the finding represented a maintenance error which was not identified by Energy Northwest prior to returning E-TR-S to service. Additionally, the finding was associated with a human error which affected the availability of E-TR-S and therefore affected the mitigating system cornerstone objective to ensure the availability of systems that respond to initiating events. The availability was affected because Energy Northwest had to take the transformer out of service to repair the damaged insulation and lead. Using Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have very low risk significance (Green) because there was no actual loss of safety function, the finding was not a design qualification issue, and the finding was not potentially risk significant due to external events. The finding had crosscutting aspects in the area of human performance in that the electricians failed to ensure the proper configuration of the wiring for the transformer and failed to meet the requirement of a procedural step during the maintenance activity.

Enforcement. Although the electricians failed to terminate the E-TR-S current transformer in accordance with a work order, no violations of NRC requirements were identified because E-TR-S, although required to be operable per technical specifications, is not a safety-related component and is therefore not subject to 10 CFR 50, Appendix B, requirements (FIN 50-397/05-04-02, Failure to Correctly Terminate Current Transformer Lead Results in Oil Leak). Energy Northwest documented the issue in PER 205-0434. Immediate corrective actions included repair of the current transformer and E-TR-S.

1R20 Refueling and Outage Activities (71111.20)

.1 Forced Outage FO-05-02

a. Inspection Scope

The inspectors reviewed the following risk significant outage activities for the sample listed below to verify defense in depth commensurate with the outage risk control plan and compliance with the technical specifications: (1) the outage risk control plan; (2) reactor coolant system instrumentation; (3) electrical power; (4) decay heat removal; (5) heatup and cooldown activities; and (6) licensee identification and implementation of appropriate corrective actions associated with refueling and outage activities.

- Forced Outage FO-05-02; June 24 to 30, 2005

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed the Updated Final Safety Analysis Report, procedure requirements, and Technical Specifications to ensure that the seven surveillance activities listed below demonstrated that the SSC's tested were capable of performing their intended safety functions. The inspectors either witnessed or reviewed test data to verify that the following significant surveillance test attributes were adequate: (1) preconditioning; (2) evaluation of testing impact on the plant; (3) acceptance criteria; (4) test equipment; (5) procedures; (6) jumper/lifted lead controls; (7) test data;

(8) testing frequency and method demonstrated Technical Specification operability; (9) test equipment removal; (10) restoration of plant systems; (11) fulfillment of ASME Code requirements; (12) updating of performance indicator data; (13) engineering evaluations, root causes, and bases for returning tested SSC's not meeting the test acceptance criteria were correct; (14) reference setting data; and (15) annunciators and alarms setpoints. The inspectors also verified that the licensee identified and implemented any needed corrective actions associated with the surveillance testing.

- ISP-MS-Q921; LPCS/RHR/ADS Actuation on Reactor Level 1 and RCIC Actuation on Reactor Level 2 - CFT/CC; Revision 2; July 1, 2005

- ISP-CRD-Q402; RPS-SDV Level Transmitter Channels B and D, CFT; Revision 10; July 16, 2005
- ISP-MS-Q903; RPS, Reactor Vessel Steam Dome Pressure - High Div 1 (A & C) - CFT/CC; Revision 6; July 6, 2005

- OSP-RHR/IST-Q703; RHR Loop B Operability Test; Revision 19; September 15, 2005

- ESP-BATT-W101, Weekly Battery Test; Revision 9

- PPM 2.11.5; Floor Drain System, Manual Determination of Drywell Unidentified Leakage; Revision 29; July 15, 2005

- ESP-SM7UV-M401; 4.16 KV Emergency Bus Degraded Undervoltage (SM7) - CFT; Revision 7; July 10, 2005

The inspectors completed seven samples. Included in the samples was one in-service test associated with the performance testing of RHR Loop B and one test associated with the manual determination of unidentified reactor coolant system leakage.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed the Updated Final Safety Analysis Report, plant drawings, procedure requirements, and Technical Specifications to ensure that the one temporary modifications listed below was properly implemented. The inspectors: (1) verified that the modification did not have an affect on system operability/availability; (2) verified that the installation was consistent with the modification documents; (3) ensured that the post-installation test results were satisfactory and that the impact of the temporary modification on permanently installed SSC's were supported by the test; (4) verified that the modification was identified on control room drawings and that appropriate identification tags were placed on the affected drawings; and (5) verified that appropriate safety evaluations were completed. The inspectors verified that licensee identified and implemented any needed corrective actions associated with temporary modifications.

- TMR 05-017; Provide temporary nonsafety-related electrical power, demineralized water, service air and communications from sources in the Turbine Generator Building to a Relief valve Test Shop; July 27, 2005.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP4 Emergency Action Level and Emergency Plan Changes (71114.04)

a. Inspection Scope

The inspector performed an in-office review of Revision 41 to the Columbia Generating Station Emergency Plan, submitted July 22, 2005. This revision updated emergency planning zone evacuation time estimate information, tables, and figures with current information from the licensee's 2005 Evacuation Time Study performed according to NUREG/CR-6862, "Development of Evacuation Time Estimate Studies for Nuclear Power Plants," January, 2005. The revision was compared to its previous revision, to the criteria of NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," Revision 1, and to the requirements of 10 CFR 50.47(b) and 50.54(q) to determine if the licensee adequately implemented 10 CFR 50.54(q).

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

For the below listed drill contributing to Drill/Exercise Performance and Emergency Response Organization (ERO) Performance Indicators, the inspectors: (1) observed the training evolution to identify any weaknesses and deficiencies in classification, notification, and Protective Action Requirements development activities; (2) compared the identified weaknesses and deficiencies against licensee identified findings to determine whether the licensee is properly identifying failures; and (3) determined whether licensee performance is in accordance with the guidance of the NEI 99-02 document's acceptance criteria.

- WO 01061187; Conduct ERO Drill; The drill simulated plant casualties that included a fire in an Emergency Core Cooling System pump room, a Reactor Water Cleanup steam leak outside of primary containment and a significant radioactive release to the environment. The simulated conditions required notification and activation of ERO, notification of offsite agencies and protective action recommendations; August 30, 2005.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety (OS)

2OS2 ALARA Planning and Controls (71121.02)

a. Inspection Scope

The inspectors assessed licensee performance with respect to maintaining individual and collective radiation exposures as low as is reasonably achievable (ALARA). The inspectors used the requirements in 10 CFR Part 20 and the licensee's procedures required by Technical Specifications as criteria for determining compliance. The inspectors interviewed licensee personnel and reviewed:

- Current 3-year rolling average collective exposure.

- Ten outage work activities scheduled during the inspection period and associated work activity exposure estimates which were likely to result in the highest personnel collective exposures.

- Ten work activities from previous work history data which resulted in the highest personnel collective exposures.

- Site specific trends in collective exposures, plant historical data, and source-term measurements.

- Site specific ALARA procedures.
- Five work activities of highest exposure significance completed during the last outage.
- ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements
- Intended versus actual work activity doses and the reasons for any inconsistencies.
- Interfaces between operations, radiation protection, maintenance, maintenance planning, scheduling and engineering groups.
- Integration of ALARA requirements into work procedure and radiation work permit (or radiation exposure permit) documents.
- Person-hour estimates provided by maintenance planning and other groups to the radiation protection group with the actual work activity time requirements.
- Shielding requests and dose/benefit analyses.
- Dose rate reduction activities in work planning.
- Post-job (work activity) reviews.
- Assumptions and basis for the current annual collective exposure estimate, the methodology for estimating work activity exposures, the intended dose outcome, and the accuracy of dose rate and man-hour estimates.
- Method for adjusting exposure estimates, or re-planning work, when unexpected changes in scope or emergent work were encountered.
- Exposure tracking system.
- Use of engineering controls to achieve dose reductions and dose reduction benefits afforded by shielding.
- Exposures of individuals from selected work groups.
- Records detailing the historical trends and current status of tracked plant source terms and contingency plans for expected changes in the source term due to changes in plant fuel performance issues or changes in plant primary chemistry.

- Source-term control strategy.
- Declared pregnant workers during the current assessment period, monitoring controls, and the exposure results.
- Resolution through the corrective action process of problems identified through post-job reviews and post-outage ALARA report critiques.
- Corrective action documents related to the ALARA program and followup activities such as initial problem identification, characterization, and tracking.

Either because the conditions did not exist or an event had not occurred, no opportunities were available to review the following items:

- Self-assessments, audits, and special reports related to the ALARA program since the last inspection
- Radiation worker and radiation protection technician performance during work activities in radiation areas, airborne radioactivity areas, or high radiation areas
- Effectiveness of self-assessment activities with respect to identifying and addressing repetitive deficiencies or significant individual deficiencies

The inspectors completed 12 of the required 15 samples and 11 of the optional samples.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA2 Identification and Resolution of Problems (71152)

.1 Cross-References to PI&R Findings Documented Elsewhere

Section 4OA5.1 of this report describes a finding for the failure to promptly identify and correct numerous instances of seismically nonconforming breakers (conditions adverse to quality).

.2 Daily Corrective Action Document Review

a. Inspection Scope

The inspectors performed a review of all documented condition reports and problem evaluation reports to help identify repetitive equipment failures or specific human performance issues for followup inspection using other baseline inspection procedures. The review was accomplished by evaluating Energy Northwest's electronic condition report and problem evaluation report databases and attending periodic plant status meetings.

b. Findings

No findings of significance were identified.

.3 Annual Sample - Configuration Management of Temporary Lead Shielding

a. Inspection Scope

The inspectors selected Condition Report 2-05-02249 for detailed review, because it documented a concern that temporary shielding had not been subject to rigorous configuration management. Because the shielding was classified as temporary, plant documentation such as drawings had not been updated to show the temporary shielding installation. Also, no time limit for temporary shielding installations was specified. This condition could potentially impact engineering modifications to SSCs because of the absence of temporary shielding documentation. During the week of September 19, 2005, the inspectors reviewed the applicable administrative procedures and interviewed personnel involved in closure of the condition report. The revisions to the procedures had addressed the concerns of configuration control. Although there was no time limit on temporary shielding installations, a temporary shielding tracking log and periodic review of temporary shielding installations was found to be actively pursued. The inspectors also evaluated the issues for their potential impact on plant safety; classification and prioritization of the condition report; and timeliness of the resolution process.

b. Findings

No findings of significance were identified.

4OA3 Event Followup (71153)

.1 (Closed) Licensee Event Report (LER) 0500397/2004-005: Reactor Manual Scram During Plant Startup due to High Water Level in the Pumped Drain Tank

This event was identified as a Green finding and discussed in Section 4OA3.2 of NRC Inspection Report 05000397/2004004. During a reactor startup on August 15, 2004, the reactor operators initiated a manual reactor scram because of a decreasing RPV water level following a trip of the only running reactor feedwater pump. The feedwater pump trip was the result of the condenser hotwell level controller set at the high end of the setpoint range in an attempt to maintain a higher than normal water inventory to accommodate a water management strategy implemented during the shutdown period. This issue was documented in the licensee's corrective action program in Condition Report CR 2-04-04547. No additional issues were identified by the inspectors. This LER is closed.

.2 (Closed) LER 05000397/2004-006: Reactor Manual Scram During Reactor Startup Due to Improper Restoration of Feedwater Heater

This event was identified as a Green finding and discussed in Section 4OA3.3 of NRC Inspection Report 05000397/2004004. During a reactor startup on August 17, 2004, a licensed control room operator improperly filled a feedwater heater causing a loss of feedwater transient. The reactor operators initiated a manual reactor scram because of a decreasing RPV water level following a trip of the only running reactor feedwater pump. This issue was documented in the licensee's corrective action program in Condition Report PER 204-1042. Three corrective actions were implemented in response to this event, including additional controls on conduct of operations and disqualification and discipline of the four operators involved. No additional issues were identified by the inspectors. This LER is closed.

.3 (Closed) Licensee Event Report (LER) 05000397/2001-003-00: HPCS Inadvertently Disabled Due to Inadequate Procedural Guidance While Transferring Water From the Condensate Storage Tanks to the Suppression Pool

On May 21, 2001, with the plant in Mode 3, the High Pressure Core Spray (HPCS) system was inadvertently depressurized due to an inadequate maintenance procedure. This resulted in HPCS being declared inoperable and unable to perform its safety function. Specifically, Energy Northwest determined that procedure PPM 2.2.4, "High Pressure Core Spray," Revision 27, was inadequate in that it did not provide adequate instructions or guidance for overriding an expected HPCS pump suction switchover from the condensate storage tanks to the suppression pool. The inspectors reviewed the circumstances associated with the event and did not identify any other significant issues. However, the inspectors noted that Energy Northwest was conducting an extent of condition review associated with single train system functional failures when it was identified that this event was required to be reportable and that an inadequate procedure was the apparent cause. Therefore, the inspectors considered the finding to be licensee identified. See Section 4OA7.1 for a discussion of enforcement and characterization of the safety significance of this finding. No additional issues were identified by the inspectors. This LER is closed.

.4 Unusual Event due to Detection of a Flammable Gas in the General Services Building

a. Inspection Scope

On June 23, 2005, Energy Northwest declared an Unusual Event per Emergency Plan Implementing Procedure (EPIP) 13.1.1, "Classifying the Emergency," Revision 33, Emergency Action Level 9.3.U.3, due to detection of a flammable gas in the General Services Building (office space) which is attached to the turbine and reactor buildings in amounts that could affected the health of plant personnel or safe plant operation. The Hanford Fire Department Hazardous Material Team was called and responded to the scene. The highest level of flammability measured by Energy Northwest utilizing a portable gas meter was 50 percent of the Lower Explosive Limit (LEL). A thorough survey of the building was conducted by the Hanford Hazardous Material Team and it was determined that the building was free of any toxic gas. Energy Northwest subsequently terminated the event approximately 2 hours and 18 minutes later on June 23, 2005. During a subsequent investigation, Energy Northwest determined that the meter that was used during the event was not working properly and would not pass a calibration check. The inspector conducted an independent assessment of the event which included a review of EPIP 13.1.1 to determined the applicability for declaring the unusual event and to ensure that Energy Northwest followed applicable event response procedures. This event was entered into Energy Northwest's problem Evaluation request 205-0432.

b. Findings

No findings of significance were identified.

4OA4 Crosscutting Aspects of Findings

Section 1R19 documented a human performance crosscutting aspect associated with maintenance technicians failure to follow a work order instruction and correctly terminate a transformer lead.

4OA5 Other Activities

.1 (Closed) URI 50-397/05-08-01 and URI 50-397/05-08-02: Failure to Identify and Correct 480 V Breaker Seismic Restraint Issues / Failure to Identify and Correct a Seismically Nonconforming Configuration Related to Safety Related 4160 V Breakers

Introduction. The inspectors identified a noncited violation of 10 CFR 50, Appendix B, Criterion XVI (Corrective Actions), with two examples, because the licensee failed to promptly identify and correct conditions adverse to quality associated with seismically nonconforming 480 VAC and 4160 VAC breakers. For the first example, the licensee failed to identify dis-engaged restraint latches on 9 breakers in Motor Control Center(MCC) E-MC-4A, despite earlier, but narrowly focused, inspections for seismic issues. In the second example, the licensee missed several opportunities to identify that the front wheels of several safety-related 4160 VAC breakers did not touch the floor due to breaker-cubicle fit-up problems.

Description.

480 VAC Breaker Issues: In March 2004 the licensee identified that six breakers in MCC E-MC-4A were not properly secured to ensure seismic qualification. The breakers should have been secured with a stud, nut and washer assembly, although the assembly was not depicted on design drawings. Two of those breakers controlled the Division III diesel generator room inlet fan and the Division III diesel generator fuel oil transfer pump. The condition was documented in Problem Evaluation Request 204-0604. While the licensee had inspected other breakers for the missing assembly, they did not verify that all seismic restraints were properly configured.

While reviewing the corrective actions for the above finding, the inspectors identified a problem which led to the discovery of multiple seismically nonconforming breakers. During a walkdown of the Division III diesel generator room inlet fan breaker, the inspectors noted that a latch (required for seismic qualification) was not fully engaged. In response to the inspectors' finding, the licensee reviewed the configuration of other breakers in MCC E-MC-4A and found two basic problems:

- First, the licensee found an additional 8 out of 21 breakers where at least one of the seismic latches was not properly secured.

- Second, the licensee found that the Division III diesel generator fuel oil transfer pump breaker did not have the stud, nut and washer assembly, as noted in the first paragraph above. However, for this particular breaker, the assembly only prevented the chattering of the auxiliary contacts, which were used for indicating lights - a nonsafety related function. The breaker's safety function was not affected.

The licensee corrected the seismic qualification of the breakers and documented the concerns in Condition Reports (CR) 2-05-01801 and 2-05-01845.

The licensee performed an operability assessment and determined that the breakers with unsecured latches were degraded but still capable of performing their safety functions. The licensee reasoned that the breakers were still secured by the stud nut and washer assembly. While this was not consistent with the seismically tested configuration, the assembly provided adequate, but not optimal, seismic restraint.

4160 VAC Breaker Issues: During the Spring 2001 refueling outage, the licensee replaced 22 4160 VAC Westinghouse DHP-350 breakers with the Westinghouse DHP-VR 350 vacuum-operated breakers manufactured by Cutler-Hammer. Sixteen breakers have a safety function to reposition during design basis accidents, including those postulated accidents involving seismic events. The new breakers were utilized in power circuits for emergency diesel generators, standby service water pumps, and emergency core cooling system pumps and were installed in the old breaker cubicles. The new breakers did not have the same dimensions as the old breakers, which resulted in cubicle fit-up problems.

On May 17, 2004, an equipment operator noticed that the front wheels for one of the breakers were lifted off the floor and initiated Problem Evaluation Request 204-0775 to document the issue. The licensee checked the other safety-related 4160 VAC breakers and found that five breakers had both wheels off the floor and eight breakers had one wheel off the floor. The maximum distance between the wheels and the floor was approximately 1/16 of an inch. The licensee determined that the current breaker configuration was inconsistent with the seismically tested configuration and initiated Follow-up Assessment of Operability 204-0775 to evaluate 4160 VAC breaker operability.

The inspectors reviewed the licensee's operability determination. The licensee concluded that although the breakers were nonconforming to their seismically tested configuration, they were still capable of performing their safety function. Specifically, Calculation EQ Task W01425-01 showed that the circuit breakers would remain rigidly supported by the seismic latches, the cubicle frame, and the inboard wheels, although the outboard wheels did not contact the floor. Additional conservatism not considered in the calculation were the breakers' levering-in screws and electrical stabs which provided additional rigidity. Lack of breaker movement during normal opening and closing of the breaker also demonstrated sufficient support of the breaker during a seismic event.

While the equipment operator's identification of the problem was a positive aspect of the issue, the inspectors were concerned because the licensee had missed several prior opportunities to identify the seismically nonconforming breakers, which had likely existed since breaker installation in 2001. The missed opportunities included:

- On February 13 and 22, 2002, operators initiated Problem Evaluation Requests 202-0476 and 202-0556 to document the excessive manual force to engage the seismic latches for two of the safety-related 4160 VAC Breakers. As part of the resolution, engineers initiated a modification task to taper the seismic latches to provide a better fit.

- NRC Inspection Report 05000397/2002-005, dated June 24, 2002, discussed a White finding because the licensee: 1) failed to implement appropriate design controls to ensure that the new breakers could perform satisfactorily in service; and 2) failed to identify the cause of several failures, which were significant conditions adverse to quality.

- NRC Inspection Report 05000397/2003-009, dated November 24, 2003, discussed a Green finding associated with the licensee's failure to promptly correct a seismic qualification issue associated with safety-related 4160 VAC breaker truck-operated cell position switches.

- On December 17, 2003, the licensee initiated Problem Evaluation Request 203-4385 to document that three safety-related 4160 VAC breakers were bent horizontally across the face approximately 5 inches from the top of the panel. Excessive force to engage the seismic latches was suspected as the cause of the panel damage.

As a corrective measure, the licensee completed the modifications to the seismic latches in order to bring the 4160 VAC breakers back to their seismically tested configuration. This work was described in Work Request 29047446 and Condition Report 2-05-04675. Breaker E-CB-8/85/1, which is a feeder breaker to Turbine Service Water Pump TSW-P-1 and Bus E-SM-82, was found to have a potential non-concentric right front wheel that allows it to freely turn for one-half a revolution. The licensee is evaluating this issue under Condition Report 2-05-07232. The breaker remained operable, but potentially nonconforming, based on the licensee's previously noted operability evaluation.

These problem identification and resolution related findings are referenced in Section 4OA2.

<u>Analysis</u>. The failure to promptly identify conditions adverse to quality (seismically nonconforming breakers) was a performance deficiency. The findings were more than minor because they impacted the Mitigating Systems Cornerstone objective of availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using the Phase 1 Significance Determination Process Screening Worksheet in Inspection Manual Chapter 0609, Appendix A, the findings were of very low risk significance because they constituted design/qualification deficiencies that did not result in a loss of function per Generic Letter 91-18, "Information to Licensees Regarding NRC Inspection Manual Section on Resolution of Degraded and Nonconforming Conditions," Revision 1.

The failure to promptly identify and correct seismically nonconforming breakers, following a reasonable opportunity to do so, had cross-cutting aspects in the areas of problem identification.

Enforcement. 10 CFR Part 50, Appendix B, Criterion XVI requires, in part, that conditions adverse to quality be promptly identified and corrected. Contrary to the above, the licensee failed to promptly identify and correct numerous seismically nonconforming breakers (conditions adverse to quality), despite numerous opportunities to do so. Because these issues are of very low safety significance and have been entered into the corrective action program as Condition Reports 2-05-01854 and 02-05-01845, as well as Problem Evaluation Request 204-0775, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy (NCV 50-397/05-04-03, Failure to Promptly Identify and Correct Seismically Nonconforming Breakers).

.2 (Closed) URI 50-397/04-04-07; Retraction of Two Loss of Shutdown Cooling Events from Safety System Functional Failure Performance Indicator

Inspection report 50-397/04-04, Section 4OA5.2, documented Energy Northwest's change in characterization of the reporting basis of two LERs (LER 50-397/2003-003-00 and LER 50-397/2003-005-00) from reportable per 10 CFR 50.73(a)(2)(v) to "voluntary". Both LERs involved the interruption of flow in the residual heat removal system while in the shutdown cooling mode of operation. Additionally, both events were originally reported in 3rd quarter 2003 as mitigating systems performance indicator safety system functional failures. However, following the reclassification of the LERs to "voluntary" on May 26, 2004, Energy Northwest retracted both issues from the Safety System Functional Failure Performance Indicator in the 2nd quarter, 2004, performance indicator data submittal to the NRC. Unresolved Item 50-397/04-04-07 was opened pending the NRC's evaluation of the acceptability of not reporting both loss of shutdown cooling events and the subsequent retraction of both events from the Safety System Functional Failure Performance Indicator.

The following key communications regarding the issue occurred between NRC and Energy Northwest staff: 1) On January 13, 2004, representatives of Energy Northwest met with NRC staff to discuss the reportability of the two events and to propose that they were not reportable based on Energy Northwest's understanding of the regulations and NUREG-1022; 2) the NRC staff reviewed Energy Northwest's conclusions and determined that both events constituted a loss of safety function as communicated to Energy Northwest during a phone call on May 5, 2004; and 3) in a letter to the NRC dated May 26, 2004, Energy Northwest disagreed with this conclusion and reclassified LER 50-397/2003-003-00 and LER 50-397/2003-005-00 as "voluntary" and reported that neither event would have prevented the fulfillment of the safety functions of a system needed to remove residual heat in accordance with 10 CFR 50.73(a)(2)(v)(B).

Energy Northwest subsequently retracted both events from the Safety System Functional Failure Performance Indicator in July, 2004, thereby revising the 2nd quarter performance indicator data. The inspectors noted that if Energy Northwest had not retracted both events from the Safety System Functional Failure Performance Indicator, then the performance indicator would have been "White" for the 2nd quarter of 2004.

After additional review and consideration, the NRC staff determined that Energy Northwest misinterpreted the reporting requirements of 10 CFR 50.73(a)(2)(v)(B) and guidance provided in NUREG-1022, "Event Reporting Guidelines 10 CFR 50.72 and 50.73," Revision 2. Therefore, the NRC's original conclusion regarding reportability as communicated to Energy Northwest on May 5, 2004, remains unchanged and that both events should have been reported in accordance with the criteria provided in 10 CFR 50.73(a)(2)(v)(B) and included in the Safety System Functional Failure Performance Indicator data for the 2nd Quarter 2004 consistent with the performance indicator reporting criteria provided in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 2. NEI 99-02 provides that the definition of a safety system functional failure for performance indicator data reporting purposes is identical to the wording prescribed in 10 CFR 50.73(a)(2)(v).

The basis for the NRC staff's conclusion is that, in each event, unintentional closure of a common suction header isolation valve tripped the operating residual heat removal pump and interrupted fulfillment of the safety function to remove residual heat. In the absence of diagnostic and corrective action to reopen the isolation valve, the residual heat removal system could not have performed its safety function if called upon.

LER 50-397/2003-003-00 described that a wire had been lifted on an incorrect relay resulting in an unintentional loss of shutdown cooling flow. LER 50-397/2003-005-00 described that a loss of shutdown cooling flow occurred during a surveillance test when operators failed to anticipate that the test normally caused a loss of shutdown cooling flow.

In accordance with Manual Chapter 0305, ""Operating Reactor Assessment Program," Section 6.05.b, the NRC plans to conduct Supplemental Inspection 95001, "Inspection For One Or Two White Inputs In A Strategic Performance Area" at Columbia Generating Station to ensure that the following aspects of the "White" 2nd quarter 2004 Safety System Functional Failure Performance Indicator have been adequately assessed: (1) root causes and contributing causes have been properly identified and understood by Energy Northwest; (2) Energy Northwest's consideration of extent of condition and extent of cause; and (3) planned and completed corrective actions have been appropriately identified to prevent recurrence. The inspectors noted that the two loss of shutdown cooling events had no impact on the Safety System Functional Failure Performance Indicator data after the 2nd quarter of 2004 and the indicator has been correctly reported as "Green" since that time. This URI is closed.

4OA6 Meetings, Including Exit

On August 19, 2005, inspectors (B. Baca and G. Guerra) presented the ALARA inspection results to Mr. T. Lynch, Plant General Manager, and other members of his staff who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

On September 1, 2005 the inspector (G. Pick) presented the inspection results to Mr. S. Oxenford, Vice President, Technical Services, and other members of licensee management at the conclusion of the Heat Sink Performance biennial inspection. Proprietary information reviewed was returned to the licensee.

On September 14, 2005, inspector (P. Elkmann) conducted a telephonic exit meeting to present the inspection results to Mr. C. Moore, Supervisor, Emergency Preparedness, who acknowledged the findings. The inspector confirmed that proprietary information was not provided or examined during the inspection.

On September 26, 2005, the resident inspectors presented the inspection results to Mr. D. Atkinson, Vice President - Nuclear Generation, and other members of his staff who acknowledged the inspection findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

4OA7 Energy Northwest Identified Violations

The following violations of very low significance (Green) were identified by the licensee and are violations of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy for being dispositioned as noncited violations.

.1 Technical Specification 5.4.1.a required in part that written procedures be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, “Quality Assurance Program Requirements (Operation),” Revision 2, Appendix A, February 1978. Regulatory Guide 1.33, Revision 2, Appendix A, Item 4.h., required that procedures for changing modes of operation should be prepared for emergency core cooling systems. Contrary to this requirement on May 21, 2001, system operating procedure PPM 2.2.10, “High Pressure Core Spray,” Section 5.10 provided inadequate guidance for overriding the expected HPCS pump suction switchover from the CSTs to the suppression pool. This resulted in the unintentional depressurization of the HPCS system and system inoperability. This finding was greater than minor because it was a procedure quality issue which affected the mitigating systems cornerstone objective to ensure the reliability and availability of systems that respond to initiating events to prevent undesirable consequences. Utilizing NRC Manual Chapter 0609, “Significance Determination Process,” Phase 1 Worksheet, the finding was determined to be of very low safety significance (Green) because the finding did not result in the loss of a safety function of a single train for greater than the Technical Specification allowed outage time. Energy Northwest documented the issue in PER 201-0871.

.2 Technical Specification 3.1.7.a required that with one Standby Liquid Control (SLC) subsystem inoperable to restore the subsystem to an operable condition within 7 days. Technical Specification 3.1.7.c required that if the required action of TS 3.1.7.a is not completed within the allowed outage time to be in mode 3 (hot shutdown) within 12 hours. On July 28, 2005, the licensee identified as a result of a scheduled review of the plant fuse control log that SLC pump 1A, SLC-P-1A, had been inoperable from July 6 until July 29, 2005, a period of 23 days, due to incorrect fuses which had been installed in the pump motor control circuit during maintenance on July 6. Contrary to TS 3.1.7.c, with SLC-P-1A inoperable for greater than 7 days, Energy Northwest failed to place the reactor in Mode 3. The inspectors performed a significance determination Phase 2 evaluation because the finding represented a loss of a single train for greater than its allowed outage time. A Phase 3 evaluation was performed by a regional senior reactor analyst. The senior reactor analyst performed an evaluation of ΔCDF using both the Columbia Probabilistic Safety Assessment, Revision 4.2, dated June 22, 2001, and the Standardized Plant Analysis Risk Model for Washington Nuclear 2 (ASP BWR C), Revision 3.11, and determined that the ΔCDF was less than 10^{-7}. Therefore the inspectors and the senior reactor analyst concluded that the finding was of very low risk significance (Green). The licensee documented the issue in their corrective action program in PER 205-0502.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Energy Northwest

F. Schill	Engineer, Licensing
C. Sly	Engineer, Licensing
D. Atkinson	Vice President, Nuclear Generation
S. Belcher	Manager, Operations
I. Borland	Manager, Radiation Protection
D. Coleman	Manager, Performance Assessment and Regulatory Programs
G. Cullen	Licensing Supervisor, Regulatory Programs
D. Dinger	Planning Supervisor, Radiation Protection
A. Khanpour	General Manager, Engineering
W. LaFramboise	Manager, Technical Engineering
T. Lynch	Plant General Manager
W. Oxenford	Vice President, Technical Services
J. Parrish	Chief Executive Officer
C. Moore	Supervisor, Emergency Preparedeness

NRC Personnel

R. Cohen	Resident Inspector
Z. Dunham	Senior Resident Inspector

ITEMS OPENED AND CLOSED

Items Opened, Closed, and Discussed During this Inspection

Opened

50-397/05-04-01	URI	Adequacy of Design of the Reactor Core Isolation Cooling System and the Keepfill Pump (Section 1R17)

Opened and Closed

50-397/05-04-02	FIN	Failure to Correctly Terminate Current Transformer Lead Results in Oil Leak (Section 1R19)
50-397/05-04-03	NCV	Failure to Promptly Identify and Correct Seismically Nonconforming Breakers (Section 4OA5.1)

Closed

50-397/2001-03	LER	Inoperable High Pressure Core Spray (HPCS) System due to low system pressure (Section 4OA3.3)

50-3972004-05	LER	Reactor Manual Scram During Plant Startup due to High Water Level in the Pumped Drain Tank (Section 4OA3.1)
50-397/2004-06	LER	Reactor Manual Scram During Reactor Startup Due to Improper Restoration of Feedwater Heater (Section 4OA3.2)
50-397/05-08-01	URI	Failure to Identify and Correct 480 V Breaker Seismic Restraint Issues (Section 4OA5.1)
50-397/05-08-02	URI	Failure to Identify and Correct a Seismically Nonconforming Configuration Related to Safety Related 4160 V Breakers (Section 4OA5.1)
50-397/04-04-07	URI	Retraction of Two Loss of Shutdown Cooling Events from Safety System Functional Failure Performance Indicator (Section 4OA5.2)

Discussed

None

PARTIAL LIST OF DOCUMENTS REVIEWED

Procedures and Instructions

SOP-RCIC-STBY; Placing RCIC is standby status; Revision 0

SOP-DG2-STBY; Emergency Diesel Generator (Div 2) Standby Lineup; Revision 4

ESP-BAT-W101; Weekly Battery Testing; Revision 9

ABN-ELEC-125VDC; Plant BOP, Div 1, 2,& 3 125 VDC Distribution System Failures; Revision 3

PPM 15.1.14; Pre-Action and Deluge Systems Flow Switch CFT; Revision 10

PPM 15.2.23; Zone 51, 52, 54, 55, 57 Through 64, 68 and 69 Thermal Detector - Channel Functional Test; Revision 6

PPM 1.3.10; Plant Fire Protection Program Implementation; Revision 28

PPM 1.3.76; Integrated Risk Management; Revision 4

PPM 1.5.14; Risk Assessment and Management for Maintenance/Surveillance Activities; Revision 15

PPM 10.2.53; Seismic Requirements for Scaffolding, Ladders, Man-Lifts, Tool Gang Boxes, Hoists, and Metal Storage Cabinets; Revision 23

GEN-RPP-02; Alara Planning and Radiation Work Permits; Revision 12

GEN-RPP-14; Control of Temporary Shielding; Revision 4

PPM 1.3.9; Temporary Modifications; Revision 39

PPM 1.3.62; Use of Cable Ties (Tie Wraps); Revision 3

PPM 1.3.68; Work Management Process; Revision 7

PPM 13.14.4; Emergency Equipment Maintenance and Testing; Revision 42

CI-11.14; Corrosion Rate Measurements; Revision 4

CI-11.15; Coupon Replacement in Corrosion Monitoring Loops; Revision 1

OSP-SW/IST-Q701; Standby Service Water Loop A Operability; Revision 11

OSP-SW/IST-Q702; Standby Service Water Loop B Operability; Revision 9

OSP-SW/IST-Q703; HPCS Service Water Operability; Revision 5

OSP-SW-M101; Standby Service Water Loop A Valve Position Verification; Revision 18

OSP-SW-M102; Standby Service Water Loop B Valve Position Verification; Revision 13

OSP-DG2-STBY; Emergency Diesel Generator (DIV 2) Standby Lineup; Revision 4

OSP-ELEC-M702; Diesel Generator 2 - Monthly Operability Test; Revision 23

OSP-ELEC-M701; Diesel Generator 2 - Monthly Operability Test; Revision 21

OSP-SW-Q101; SW Spray Pond Average Sediment Depth Measurement; Revision 29

PPM 1.5.9; Plant Performance Monitoring Program; Revision 8

PPM 8.4.42; Thermal Performance Monitoring of RHR-HX-1A and RHR-HX-1B; Revision 6

PPM 8.4.62; Thermal Performance Monitoring of DCW-HX-1B1 and DCW-HX-1B2; Revision 6

PPM 8.5.13; Chemical Cleaning of SW Room Coolers; Revision 0

PPM 12.14.1; Chemical Treatment of Standby Service Water; Revision 13

QCI 2-2; Eddy Current Examination of Heat Exchanger Tubing; Revision 7

QCI 2-3; Analysis of Heat Exchanger Eddy Current Examination Data; Revision 6

SOP-SW-COLD WEATHER; Standby Service Water Cold Weather Operations; Revision 2

SWP-CHE-02; Chemical Process Management and Control; Revision 11

TSP-SW-A101; Service Water Loop A Cooling Coil Heat Load Capacity Test; Revision 0

TSP-SW-A102; Service Water Loop B Cooling Coil Heat Load Capacity Test; Revision 0

PPM 11.2.2.11; Exposure Evaluations for Maintaining TEDE ALARA; Revision 3

GEN-RPP-01; ALARA Program Description; Revision 5

GEN-RPP-02; ALARA Planning and Radiation Work Permits; Revision 11

GEN-RPP-09; Monitoring of Declared Pregnant Women and Authorized Minors; Revision 2

GEN-RPP-13; ALARA Committee; Revision 4

GEN-RPP-14; Control of Temporary Shielding; Revision 4

PPM 2.11.5; Floor Drain System; Revision 29

ESP-SM7UV-M401; 4.16 KV Emergency Bus Degraded Undervoltage (SM7) - CFT; Revision 7

PPM 4.840.A2; 840.2 Annunciator Panel Alarms; Revision 5

PPM 1.3.47; Fuse Replacement Control; Revision 9

SOP-RCIC-Injection; RCIC RPV Injection; Revision 2

ABN-RCIC-ISOL/Trip; RCIC Recovery Following an Isolation or Trip; Revision 2

ESP-B12-Q101; Quarterly Battery Testing 125 VDC E-B1-2; Revision 7

OSP-RFW/IST-Q701; RFW Valve Operability - Shutdown; Revision 6

Calculations

ME-02-01-30; Determination of RCIC Availability Without Standby Service Water; Revision 0

ME-02-91-28; Heat Exchanger Effectiveness Evaluation; Revision 0

ME-02-91-42; Service Water Flow Rate to DCW Heat Exchangers; Revision 1

ME-02-92-14; Evaluation of Low Service Water Flow to DCW Heat Exchanger; Revision 1

ME-02-92-43; Room Temperature Calculation for DG Building; Reactor Building, and Service Water Pumphouse Under Design Basis Conditions; Revision 7

ME-02-95-25; Evaluation of Standby Service Water Capability; Revision 1

ME-02-97-08; Evaluate Ability of the Service Water System to Provide Cooling to the Diesel Generators While Operating in a RPV/Containment Flooding Configuration; Revision 0

ME-02-99-03; Alternate Decay Heat Removal Using RHR With Suction From the Fuel Pool; Revision 0

ME-02-04-02; Minimum Allowable Service Water Flows in Winter; Revision 0

NE-02-82-13; Fuel Pool Temperature Transient and Steady State Calculation Revision 2

ME-02-02-44; Standby Service Water Pumphouses 1A and 1B - Flooding Analysis; Revision 0

Calculation Modification Requests

94-1104	94-1115	95-0656	97-0010	98-0177	1455
3610	3585				

Drawings

GE Drawing 807E173TC; RCIC Elementary Diagram and Relay Tabulation; Revision 32

Flow Diagram M512-4; Diesel Oil and Miscellaneous Systems; Revision 8

Flow Diagram M519; Reactor Core Isolation Cooling System; Revision 86

EWD-46E-106A; Electrical Wiring Diagram AC Electrical Distribution Systems 4.16 kv SWGR SM-7 Crit Bus 7 Undervoltage; Revision 16

EWD-10E-003; Electrical Wiring Diagram Standby Liquid Control System Pump SLC-P-1A and Squib Valve SLC-V-4A; Revision 14

Work Orders / Work Requests

WO 01058493-01	WO 01068515-01	WO 01009801	WO 01014488
WO 01022197	WO 01022656	WO 01022657	WO 01034934
WO 01037255	WO 01037256	WO 01038813	WO 01039358
WO 01043656	WO 01045230	WO 01050492	WO 01050546
WO 01052777	WO 01053303	WO 01053441	WO 01053442
WO 01054172	WO 01054705	WO 01054724	WO 01054790

WO 01054791	WO 01056593	WO 01056666	WO 01058472
WO 01058634	WO 01058827	WO 01059360	WO 01059384
WO 01060142	WO 01060284	WO 01064376	WO 01064456
WO 01064519	WO 01064583	WO 01069288	WO 01069414
WO 01070387	WO 01072732	WO 01072733	WO 01073762
WO 01073856	WO 01077640	WO 01078143	WO 01078483
WO 01078500	WO 01078607	WO 01079758	WO 01083141
WO 01083197	WO 01083269	WO 01086048	WO 01087250
WO 01087289	WO 01087370	WO 01089912	WO 01091013
WO 01091095	WO 01091096	WO 01091512	WO 01091584
WO 01092504	WO 01092506	WO 01094773	WO 01095543
WO 01095602	WO 01020837	WO 01063246	WO 01093021
WO 01101602	WO 01100222	WO 01102092	WO 01098390
WO 01081617			

<u>Other</u>

Columbia Operational Challenges List

IN 83-64; Lead Shielding Attached to Safety-Related Systems Without 10 CFR 50.59 Evaluations

Action Request AR8319

XF4201 BX2301 RDF901 RDG001 TMR 05-17

Technical Memorandum 2050; Classification of Design Base Functions and Primary Containment Isolation Boundaries of the RCIC System

FSAR; Section 3.4; Amendment 57

FSAR; Section 3.8; Amendment 54/57

FSAR; Section 9.2; Amendment 57

FSAR; Appendix F; Amendment 54

Columbia Generating Station Pre-Fire Plan; Revision 6

NRC Inspection Report 05000397/2004004

Conceptual Design Report 88-0450; Cathodic Protection for Spray Pond 1A Supports; Revision 0

EPRI NP-7552; Heat Exchanger Performance Monitoring Guidelines; dated December 1991

Final Safety Analysis Report; Sections 9.2.5, Ultimate Heat Sink, and 9.2.7; Standby Service Water System

Generic Letter 89-13; Service Water System Problems Affecting Safety-Related Equipment; dated July 18, 1989

Generic Letter 89-13; Supplement 1, Service Water System Problems Affecting Safety-Related Equipment; dated April 4, 1990

Letter G02-89-205; Generic Letter 89-13 - Service Water System Problems Affecting Safety-Related Equipment; dated November 9, 1989

Letter G02-90-017; Response to Generic Letter 89-13 - Service Water System Problems Affecting Safety-Related Equipment; dated February 5, 1990

Letter G02-91-041; Response to Generic Letter 89-13 - Service Water System Problems Affecting Safety-Related Equipment; dated February 28, 1991

NUREG/CR-5685; Generic Service Water System Risk-Based Inspection Guide

Thermal performance trend graphs for Standby Service Water Pump A room cooler; Diesel Generator B heat exchangers, and Residual Heat Removal A heat exchanger

Plant Modification Request 84-1059-00; Chemical Addition System For Service Water Spray Ponds

Plant Modification Request 86-0068-00; Service Water Corrosion Monitoring Coupon Station

Regulatory Commitment Change RCC-110797-00; G02-90-017, WNP-2 Response to USNRC GL 89-13

Specifications for the residual heat removal, spent fuel pool cooling, reactor core isolation cooling pump room cooler, and standby service water pump room coolers

Self-assessment SA-2003-0051; Heat Exchanger Program Self-assessment; dated October 3, 2003

Standby Service Water System Description; Revision 13

Standby Service Water System Design Specification

Technical Memorandum TM-2111; Thermal Performance Testing of Air-to-Water Heat Exchangers in the WNP-2 Service Water System; Revision 0

WNP-2 Service Water System Site Information Report; dated August 22, 1989

Standby service water system health reports for Calendar Years 2003, 2004, and 2005

Standby Service Water System Performance Monitoring Plan

Inservice test program trend data for Calendar Years 2003, 2004, and 2005 for selected standby service water system components

1996 - 2004 BRAC Drywell Survey Results

Accelerated Dose Reduction Strategy for Refueling Outage 17

Comparison Study for Cavity Decontamination Possibilities in Refueling Outage 17 Dose Reduction Strategy; Revision 3

Dosimetry records for three Declared Pregnant Females

Radiologically Controlled Area Exit Dose Transactions for selected workers

Refueling Outage 17 ALARA Review

2005 Temporary Shielding Tracking Log

Basic Design Change 394; RCIC Water Hammer Prevention System Upgrade

Reactor Trip Report 205-03; June 23, 2005

<u>PER/Condition Reports</u>

PER 204-1092	CR 2-05-05820	CR 2-05-06542	LER 2004-006
CR 2-04-04547	CR 2-05-06682	CR 2-05-05068	CR 2-05-05078
CR 2-05-07280	LER 2004-005	CR 2-05-04532	CR 2-05-04445
CR 2-04-01208	CR 2-04-01977	CR 2-04-03730	CR 2-04-04167
CR 2-04-04171	CR 2-04-05191	CR 2-04-05737	CR 2-04-06176
CR 2-04-06542	CR 2-04-06857	CR 2-05-00126	CR 2-05-00188
CR 2-05-01706	CR 2-05-02695	CR 2-05-04277	CR 2-04-03730

PER 203-0169	PER 203-1642	PER 203-1661	PER 204-0033
PER 204-0246	PER 204-0366	CR 2-04-01208	CR 2-04-01977
CR 2-04-04167	CR 2-04-04171	CR 2-04-05191	CR 2-04-05737
CR 2-04-06176	CR 2-04-06542	CR 2-04-06857	CR 2-05-00126
CR 2-05-00188	CR 2-05-01706	CR 2-05-02695	CR 2-05-04277
CR 2-05-04445	CR 2-05-04532	CR 2-05-06682	CR 2-05-05068
CR 2-05-05078	CR 2-05-05820	CR 2-05-06542	CR 2-05-1953
CR 2-05-2730	CR 2-05-3003	CR 2-05-3197	CR 2-05-3204
CR 2-05-3249	CR 2-05-3285	CR 2-05-3291	CR 2-05-3312
CR 2-05-3386	CR 2-05-3714	CR 2-05-3972	CR 2-05-3986
CR 2-05-4084	CR 2-05-4468	CR 2-05-4521	CR 2-05-4624
CR 2-05-4752	CR 2-05-4876	CR 2-05-5213	CR 2-05-5568
CR 2-05-5704	PER 205-0502	CR 2-04-03099	CR 2-04-00001
CR 2-04-03043	CR 2-04–03044	CR 2-04-06597	CR 2-05-04320
CR 2-05-0461	CR 2-05-04803	CR 2-05-05526	CR 2-04-01355
CR 2-04-01356	CR 2-04-02048	CR 2-04-02050	CR 2-04-03708
CR 2-04-04313	CR 2-04-04504	CR 2-04-05200	CR 2-04-05467
CR 2-04-05480	CR 2-04-05852	CR 2-04-06442	CR 2-04-07009
CR 2-04-07045	CR 2-05-00095	CR 2-05-00119	CR 2-05-01114
CR 2-05-02663	CR 2-05-03086	CR 2-05-05482	CR 2-05-06633
CR 2-05-06749	CR 2-05-05294	CR 2-04-02818	CR 2-04-04050
CR 2-04-04998	CR 2-04-05000	CR 2-04-06138	CR 2-04-06172
CR 2-04-06708	CR 2-05-00972	CR 2-05-00984	CR 2-05-01148
CR 2-04-06847	CR 2-04-06861	CR 2-05-00425	CR 2-05-00681
CR 2-05-01178	CR 2-05-02796	CR 2-05-04006	CR 2-05-04179

CR 2-05-068057	PER 205-0386	PER 204-0066	CR 2-04-07002
CR 2-05-02333	CR 2-05-02796	CR 2-05-03945	CR 2-05-04552
CR 2-05-04716	CR 2-04-01297	CR 2-05-00891	CR 2-05-04011
CR 2-05-04380	CR 2-05-04792	CR 2-05-05616	PER 204-0280
CR 2.05-06417	PER 201-0871	PER 205-0434	CR 2-05-06556
PER 205-0502	PER 205-0429	CR 2-05-05566	CR 2-05-05739
CR 2-05-06087	PER 205-0500	PER 203-3059	

Radiation Work Permits

30001237	30001238	30001239	30001240	30001245	30001246
30001255	30001265	30001275	30001285	30001286	30001291
30001292	30001298	30001299	30001300	30001310	30001311
30001325	30001329	30001336	30001345	30001387	30001421
30001491	30001492	30001493	30001495	30001539	30001549
30001551	30001556				

2005 ALARA Committee Minutes

April 19, May 13, May 23, June 30, July 26

Temporary Shielding Requests

05-10	05-12	05-20

COLUMBIA GENERATING STATION
Incorrect Fuses Installed in the Standby Liquid Control Pump 1A Circuitry
SDP Phase 3 Analysis

I. Performance Deficiency:

On July 6, 2005, the licensee failed to meet the requirements of their fuse control program resulting in the installation of the incorrect fuses in the motor starter control circuit for Standby Liquid Control Pump 1A. This resulted in the Pump being incapable of starting and performing its intended risk-significant function.

II. Safety Significance:

The analyst determined that the performance deficiency represented a finding of very low risk significance. This was based on a Phase 3 evaluation using NRC Inspection Manual Chapter 0609, Appendix A, “Significance Determination of Reactor Inspection Findings for At-Power Situations."

III. Description of Condition:

On July 6, as part of performing maintenance on Pump SLC-P-1A, “Standby Liquid Control Pump 1A,” the pump control power fuses were replaced as directed by a work order. The electrician retrieved replacement fuses from the tool crib but failed to retrieve “like for like” fuses as required by the fuse control program instruction. The fuse which was installed was a quick-clearing fuse. The required fuse was a slow-clearing fuse. A slow-clearing fuse is needed to ensure that the fuses do not inadvertently open during brief moments of increased starting current while a large motor is starting. Licensee personnel determined that the quick-clearing fuse type installed would most likely open during a pump actuation causing the pump to trip. The installation of incorrect fuses was discovered during a review of the fuse control log on July 28. The correct fuses were installed on July 29 restoring the pump to an operable status.

The standby liquid control system is manually initiated from the control room, as directed by the emergency operating procedures, if the operator determines that the reactor cannot be shut down, or kept shut down, with the control rods. The standby liquid control system is used in the event that not enough control rods can be inserted to accomplish shutdown and cooldown in the normal manner. The system injects borated water into the reactor core, via the high pressure core spray sparger, to compensate for all of the various reactivity effects that could occur during plant shutdown and cooldown. The system is designed to inject a quantity of boron that produces a concentration of 660 ppm natural boron in the reactor coolant system. The injection rate required by the ATWS rule necessitates injection using both standby liquid control pumps.

The inspectors noted that the standby liquid control system can be used as an alternate method of water injection for core cooling (over short periods of time) in accordance with the emergency operating procedures but this is not a credited function.

IV. Characterization of Risk:

In accordance with NRC Inspection Manual Chapter 0612, Section 05.03, “Screen for Minor Issues,” the inspectors determined that the finding was more than minor. This finding was associated with the equipment performance, availability attribute of the Mitigating Systems cornerstone and was determined to affect the objective of that cornerstone. Specifically, the finding resulted in a reduction of the reliability of Standby Liquid Control Pump 1A in responding to and mitigate an anticipated transient without scram (ATWS).

The inspectors evaluated the issue using the SDP Phase 1 Screening Worksheet for the Initiating Events, Mitigating Systems, and Barriers Cornerstones provided in NRC Inspection Manual Chapter 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations." In order to achieve its design basis function of injecting boron at a rate sufficient to meet ATWS event requirements per 10 CFR 50.62, both standby liquid control pumps are required to inject boron at the necessary injection rate. Therefore, the entire reactivity control system mitigating function for an ATWS is affected by an inoperable pump. It is unclear whether the total risk-significant function was lost. Regardless, the screening indicated that a Phase 2 estimation was required because the performance deficiency represented an actual loss of safety function of a single train of standby liquid control for greater than its Technical Specification Allowed Outage Time of seven days.

In accordance with NRC Inspection Manual Chapter 0609, Appendix A, Attachment 1, "User Guidance for Determining the Significance of Reactor Inspection Findings for At-Power Situations," the inspectors estimated the risk of the subject finding using the Risk-Informed Inspection Notebook for Columbia Generating Station, Revision 1. The inspectors made the following assumptions:

1) The incorrect fuses were installed on July 6 and remained in the circuit until July 29 when they were replaced. This represented an exposure time of 23 days. Therefore, the 3 to 30-day exposure window was used.

2) The quick clearing fuses installed in the Standby Liquid Control Pump circuitry would have opened during a pump demand, causing the pump not to start.

3) Table 2 of the Risk-Informed Inspection Notebook identified that the only initiating event scenario impacted by a finding that affects standby liquid control is an ATWS.

4) Table 1 of the Risk-Informed Inspection Notebook identified that the Initiating Event Likelihood (IEL) for an ATWS having an exposure time window of 3 - 30 days was 6.

5) The Columbia standby liquid control system was originally designed to meet the requirements of 10 CFR, Appendix A, Criterion 29, “Protection Against Anticipated Operational Occurrences,” with two pumps capable of independently shutting down the reactor. However, the system was incapable of meeting the revised requirements in 10 CFR 50.62, “Requirements for Reduction of Risk from

Anticipated Transient Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants," with only a single pump. Therefore, the Risk-Informed Inspection Notebook requires that both pumps be functional to give mitigating system credit to the standby liquid control system.

6) Given Assumption 5, the inspectors adjusted the reactivity control mitigation capability (SLC) from a credit of 1 to no credit.

7) No credit was given for recovery of the failed circuit by replacing the fuses following a pump demand and subsequent opening of the fuse element. During an ATWS, starting the standby liquid control system is required within 20 minutes to prevent core damage. Therefore, there was insufficient time to diagnose the failed circuit, identify the failed fuse, and replace it. Additionally, operator credit is not warranted because, with time being critical, the operator or electrician replacing the fuse would most likely replace it with a fuse of the same design.

Based on the above assumptions, only one sequence in the Risk-Informed Inspection Notebook, ATWS worksheet was applicable. The resulting sequence is provided below:

Anticipated Transients without Scram Worksheet Results			
Sequence	IEL	Mitigating Functions	Result
4	6	SLC	6

By application of the Counting Rule, the internal event risk contribution of this finding was approximately 3×10^{-6}. In a memorandum dated April 28, 2002 (Reinhart to Carpenter) regarding: "Results of the Columbia Generating Station SDP Phase 2 Notebook Benchmarking Visit," the team concluded in Attachment A, Table 1, "Comparison of Component Sensitivity Calculations between Phase 2 Worksheets and Columbia RAWs," that the Phase 2 result for a single failed standby liquid control injection pump was conservative by one order of magnitude. Therefore, a senior reactor analyst determined that a Phase 3 analysis of this performance deficiency was appropriate.

<u>Phase 3 Evaluation</u>:

The analyst utilized Assumptions 2, 5, and 7 from the Phase 2 estimation. Additionally, the analyst used the dates listed in Assumption 1. However, an exposure time (EXP) of 23 days was used, as opposed to the Phase 2 order-of-magnitude exposure range. The analyst then evaluated the risk associated with the performance deficiency using two separate tools:

1) Licensee's Probabilistic Model:

The Columbia Probabilistic Safety Assessment, Revision 4.2, dated June 22, 2001, provides a risk-achievement worth (RAW) of 1.18 for the failure of a standby liquid control pump. Given the model's baseline core damage frequency (CDF_{Base})

of 2.25×10^{-5}/yr, the analyst calculated the change in CDF as follows:

$$\Delta CDF = [(CDF_{Base} * RAW) - CDF_{Base}] * EXP$$

$$= [(2.25 \times 10^{-5}/yr * 1.18) - 2.25 \times 10^{-5}/yr] * [22 \text{ days} / 365 \text{ days/yr}]$$

$$= 4.1 \times 10^{-6}/yr * 6.1 \times 10^{-2} \text{ yrs}$$

$$= 2.5 \times 10^{-7}$$

2) Standardized Plant Analysis Risk Model:

The analyst used the Standardized Plant Analysis Risk Model for Washington Nuclear 2 (ASP BWR C), Revision 3.11, to evaluate the risk associated with the subject performance deficiency. The analyst set Basic Event SLC-MDP-FS-1A, "SLC MDP 1A Fails to Start," to the house event, "TRUE," indicating that the pump failed to start. The resulting value for CDF (CDF_{Case}) was 1.407×10^{-5}/yr. Given the model's baseline core damage frequency (CDF_{Base}) of 1.137×10^{-5}/yr, the analyst calculated the change in CDF as follows:

$$\Delta CDF = [CDF_{Case} - CDF_{Base}] * EXP$$

$$= [1.407 \times 10^{-5}/yr - 1.137 \times 10^{-5}/yr] * [22 \text{ days} / 365 \text{ days/yr}]$$

$$= 2.7 \times 10^{-6}/yr * 6.1 \times 10^{-2} \text{ yrs}$$

$$= 1.6 \times 10^{-7}$$

The analyst noted that both results were within a factor of two with each other, indicating good correlation between the models. Additionally, these values indicated that the Phase 2 result obtained from the Risk-Informed Inspection Notebook was, in fact, an order of magnitude off. Therefore, the analyst concluded that the best characterization of the risk related to this performance deficiency was very low risk significance, given the change in core damage frequency from internal initiators quantified by the Standardized Plant Analysis Risk Model to be 1.6×10^{-7}.

<u>External Events</u>:

The plant-specific SDP worksheets do not currently include initiating events related to fire, flooding, severe weather, seismic, or other external initiating events. In accordance with Manual Chapter 0609, Appendix A, Attachment 1, Step 2.5, "Screening for the Potential Risk Contribution Due to External Initiating Events," experience with using the Site Specific Risk-Informed Inspection Notebooks has indicated that accounting for external initiators could result in increasing the risk significance attributed to an inspection finding by as much as one order of magnitude.

The analyst reviewed the WNP-2 Individual Plant Examination for External Events Main Report, dated June 1995 (IPEEE). The analyst assumed that only external initiators that increased the likelihood of an ATWS would be affected by the subject performance deficiency. Of the events that could potentially affect Columbia, the analyst ruled out all but the following because these events would not increase the likelihood of an ATWS:

- Seismic Events
- External Floods
- Internal Floods

The analyst determined that the elevation of the hydraulic control units was located at Elevation 472 and that ground level was approximately Elevation 441. Additionally, the 441-foot elevation has open stairways that would drain water from internal pipe breaks. Therefore, the analyst determined that a flood induced ATWS was not a credible external event.

In the IPEEE, the licensee documented that analysis showed no additional credible seismic failure modes beyond the baseline mechanical failure modes developed for the internal events analysis of ATWS. Therefore, a seismically induced ATWS was not considered credible beyond the seismically-induced loss of offsite power rate. This loss of offsite power mode is included in the calculated initiating event likelihood used in the internal events assessment.

Based on this review, the analyst concluded that the risk from external events related to the subject performance deficiency was bounded by the internal events analysis. Therefore, no additional external initiated risk was assumed as the analyst's best estimate.

<u>Large Early Release Frequency</u>:

In accordance with Manual Chapter 0609, Appendix A, Attachment 1, Step 2.6, "Screening for the Potential Risk Contribution Due to LERF," the analyst assessed the impact of large early release frequency because the Phase 2 SDP result provided a risk significance estimation of 7.

Only a subset of those sequences contributing to CDF significance of a finding has the potential to impact LERF. For boiling water reactor Mark II containments, findings related to ATWS do potentially impact LERF. In accordance with Manual Chapter 0609, Appendix H, "Containment Integrity Significance Determination Process," Table 5.1, these sequences must be evaluated using the Phase 2 estimation approach.

Table 5.2, "Phase 2 Assessment Factors - Type A Findings at Full Power," provides a LERF factor of 0.4 for Mark II containments during ATWS sequences. Therefore, the estimated change in LERF (ΔLERF) can be calculated by multiplying the change in core damage frequency and this LERF factor as follows:

$$\Delta LERF = 1.6 \times 10^{-7} * 0.4$$

$$= 6.8 \times 10^{-8}$$

Because the ΔLERF is less than the threshold value of 1.0×10^{-7}, this finding is of very low risk significance (green).

V. Conclusion:

The performance deficiency resulted in a finding that was of very low risk significance (green). The best estimate change in core damage frequency was 1.6×10^{-7} representing the risk related to internal initiators. The change in risk related to external events as well as the change in large-early release frequency were evaluated and the impact of this finding was considered to be negligible.

VI. References:

Draft NRC Inspection Report Input for 50-397/2005004
Draft Phase 2 Estimation provided by lead inspector
Columbia Generating Station, Technical Specification 3.1.7 and basis.
NRC Inspection Manual Chapter 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations"
NRC Inspection Manual Chapter 0612, "Power Reactor Inspection Reports"
Risk-Informed Notebook for Columbia Generating Station, Revision 1

VII. Participation:

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