UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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ARLINGTON, TEXAS 76011-4005

November 7, 2007

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

SUBJECT: COLUMBIA GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000397/2007004

Dear Mr. Parrish:

On September 28, 2007, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Columbia Generating Station. The enclosed inspection report documents the inspection results, which were discussed on October 1, 2007, with Mr. T. Lynch and other members of your staff.

The inspection 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 self-revealing finding of very low safety significance (Green) which did not involve a violation of NRC requirements. Additionally, a licensee-identified violation which was determined to be of very low safety significance is listed in this report. 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 (NCV) consistent with Section VI.A.1 of the NRC Enforcement Policy. If you contest any NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the 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.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) 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 Website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

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

Docket: 50-397
License: NPF-21

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NRC Inspection Report 05000397/2007004

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SUNSI Review Completed: CEJ ADAMS: √ Yes ☐ No Initials: CEJ
√ Publicly Available ☐ Non-Publicly Available ☐ Sensitive √ Non-Sensitive

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SRI:DRP/A	RI:DRP/A	PE:DRP/A	BC:DRP/A	BC:DRS/EB1
ZKDunham	RBCohen	MOHayes	CEJohnson	WBJones
E-CEJ	E-CEJ	/RA/	/RA/	/RA/
11/05/07	11/05/07	11/07/07	11/07/07	10/18/07
BC:DRS/PSB	BC:DRS/OB	BC:DRS/EB2		
MPShannon	ATGody	LJSmith		
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U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	50-397
License:	NPF-21
Report:	05000397/2007004
Licensee:	Energy Northwest
Facility:	Columbia Generating Station
Location:	Richland, Washington
Dates:	June 30 through September 28, 2007
Inspectors:	Z. Dunham, Senior Resident Inspector, Project Branch A, DRP R. Cohen, Resident Inspector, Project Branch A, DRP M. Hayes, Project Engineer, Project Branch A, DRP
Approved By:	C. E. Johnson, Chief, Project Branch A, Division of Reactor Projects
ATTACHMENT:	SUPPLEMENTAL INFORMATION

CONTENTS

SUMMARY OF FINDINGS

IR05000397/2007004; 06/30/2007 - 09/28/2007; Columbia Generating Station; Event Follow-up

The report covered a 13-week period of inspection by resident inspectors. One Green finding was 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: Initiating Events

- Green. A Green self-revealing finding was identified for the failure of operations staff to adhere to an operations instructions which provided operating expectations and standards for dealing with uncertain situations and time critical decisions. This resulted in the inadvertent loss of a condensate booster pump and a resultant reactor trip when operators attempted to shift the pump's lube oil duplex strainer with the pump in operation. This occurred while a second condensate booster pump was already out-of-service and the reactor at 70 percent power. The operating crew conducted the lube oil strainer shift even though the filter swap was not a time critical evolution and the operating condition of the pump had not been investigated. Energy Northwest entered the issue into the corrective action program and conducted a root cause evaluation.

  This finding is greater than minor because it is a human performance issue which affected both the initiating events and mitigating systems cornerstone objectives to limit the likelihood of those events that upset plant stability and ensure the availability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the loss of a condensate booster pump resulted in a loss of reactor feedwater pumps (Mitigating System) which resulted in a reactor scram on low reactor water level (Initiating Event). A Phase 1 Significance Determination Process evaluation determined that a Phase 2 evaluation was required because two cornerstones were affected by the performance deficiency (Initiating Events and Mitigating Systems). The inspectors consulted with a regional senior reactor analyst and determined that a Phase 3 analysis was required because a Phase 2 evaluation using the site specific worksheets did not adequately assess a loss of condensate booster pump event at reduced reactor power. As a result, a Phase 3 analysis was performed by the senior reactor analyst. Key assumptions included the probability of MSIV closure upon a loss of feed, operator recovery of the power conversion system following an MSIV closure, and the effect of containment failure on HPCS functionality. The core damage frequency result was less than 1.0E-6/yr. The initial screening of delta-LERF was slightly greater than 1.0E-7/yr., but a refinement of this result yielded a value less than 1.0E-7/yr.

Consequently, the significance of the finding was determined to be of very low risk significance (Green). The cause of the finding is related to the cross-cutting aspect of human performance with a decision making component (H.1.b) because operations staff failed to use conservative assumptions regarding operation of the condensate booster pump lube oil duplex strainer, contrary to relevant operations department standards and expectations. (Section 4OA3.2)

B. Licensee-Identified Violations

Violations of very low safety significance, which were identified by the licensee have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. These violations and corrective actions are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status:

The inspection period began with Columbia Generating Station shutdown in Mode 3 in forced outage FO-07-02. The reactor was brought critical on June 30, 2007, and the main generator synchronized to the grid on July 2. Power ascension was commenced with a hold at 85 percent power to support an economic dispatch request from the grid operator. The unit achieved 100 percent power on July 5. On August 2, 2007, power was reduced to 15 percent to take the main generator off line to support an emergent repair activity on one of the main generator transformers. Following the repair to the transformer, the main generator was synchronized to the grid on August 4 with 100 percent power achieved on August 6. On August 21, 2007, reactor power was reduced to 62 percent power due to a hydraulic leak which caused one of the low pressure turbine intercept valves to close. Following repairs of the hydraulic leak, power was returned to 100 percent on August 22, 2007. On September 15, 2007, reactor power was reduced to 60 percent power to perform maintenance on a reactor feedwater pump turbine governor. The reactor was returned to 100 percent power on September 18, 2007. The unit was operated at or near 100 percent power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather (71111.01)

.1 Readiness For Seasonal Susceptibilities

a. Inspection Scope

The inspectors completed a review of the licensee's readiness to accommodate ash fall at the facility due to volcanic eruption in the pacific northwest. 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 the readiness of essential systems; (2) walked down portions of the systems listed below to ensure that ash fall protection features 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.

- Diesel Generator HVAC; August 2, 2007
- Service Water Pump House HVAC; August 2, 2007

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 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.

- Low Pressure Core Spray; July 18, 2007
- Remote Shutdown Panel; July 30, 2007
- Division 1 Emergency Diesel Generator; September 10, 2007

The inspectors completed three samples.

b. Findings

No findings of significance were identified.

.2 Complete Walkdown

a. Inspection Scope

The inspectors: (1) reviewed plant procedures, drawings, the Updated Safety Analysis Report, Technical Specifications, and vendor manuals to determine the correct alignment; (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.

- High Pressure Core Spray Diesel Generator; July 11, 2007

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 the 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 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 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 - 7; Division 2 Electrical Equipment Room; July 31, 2007
- Fire Area RC-11; Unit A Air Conditioning Room Radwaste Control Building 525 Foot Elevation; August 1, 2007
- Fire Area RC-12; Unit B Air Conditioning Room Radwaste Control Building 525 Foot Elevation; August 7, 2007
- Fire Area R-18; Division 2 Motor Control Center Room Reactor Building 522 Foot Elevation; September 6, 2007
- Fire Area RC-5; Division 1 Battery Room Radwaste Control Building 467 Foot Elevation; September 6, 2007
- Fire Area RC-9; Remote Shutdown Panel Room; September 19, 2007
- Fire Area RC-10; Main Control Room; September 19, 2007
- Fire Area R-7; Residual Heat Removal Pump 2C Room; September 19, 2007

The inspectors completed eight samples.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

The inspectors: (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) verified that operator actions for coping with flooding can reasonably achieve the desired outcomes; and (4) walked down the below listed areas to verify, as applicable, the adequacy of: (a) equipment seals located below the floodline, (b) floor and wall penetration seals, (c) watertight door seals, (d) common drain lines and sumps, (e) sump pumps, level alarms, and control circuits, and (f) temporary or removable flood barriers.

- Service Water Pumphouse A; August 31, 2007

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07) (Annual)

a. Inspection Scope

On July 31, 2007, 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 for the Residual Heat Removal Heat Exchangers 1A and 1B. 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.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11) (Quarterly)

a. Inspection Scope

On September 13, 2007, 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 hydraulic Anticipated Transient Without Scram with only one Standby Liquid Control pump available, and failure of a Reactor Feedwater Pump.

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 below listed maintenance activities 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.

- EDR-FRS-623 Failed During Performance of ISP-FDR/EDR-M401; August 6, 2007

- Diesel Generator Output Breaker PER 207-0135; September 25, 2007

The inspectors completed two samples.

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 below listed assessment activities 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.

- WO 01137719; RRC-FT-14A and RRC-FT-14B Out of Service During Backfill; July 12, 2007

- WO 01130651; NDE Inspection of Spray Pond Siphon Line; September 12, 2007

- WO 01140780; Replace Recorder for Leak Detection Drywell Floor Drain and Drywell Equipment Drain; September 12, 2007

- WO 01136548; Downpower to 60 Percent Power and RFW-P-1B Planned Maintenance; September 15, 2007

The inspectors completed four samples.

b. Findings

No findings of significance were identified.

.2 Emergent Work Control

a. Inspection Scope

The inspectors: (1) verified 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) verified 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.

- WO 01113900; WEA-AD-51 Failed to Close When Required; July 29, 2007

- WO 01139198; Replace Overheated Links on E-TR-M1; August 6, 2007

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 2-07-06410; Condensate Injection Temperature; June 22, 2007
- CR 2-07-06618; Standby Gas Treatment Fan 1B2 Inoperable; July 9, 2007
- CR 2-07-06577; Reactor Recirculation Flow Instrumentation Flow Noise; July 10, 2007
- CR 2-07-07347; WEA-AD-51 Failure to Close; July 29, 2007
- PER 207-0319; Oil Leak From HPCS-P-1 Lower Bearing Oil Sump; August 22, 2007
- CR 2-07-07595; E-CB-3/8 Undervoltage Alarm; August 6, 2007

The inspectors completed six samples.

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors selected the postmaintenance test activities listed below for inspection. 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 postmaintenance testing.

- WO 01139000; Replace Damper Motor WEA-AD-51; July 29, 2007
- WO 01139111; Replace RHR-E/S-603B; August 1, 2007

- WO 011392245; Replace Switch Operator for RHR-V-48B; August 5, 2007
- WO 01137144; Trouble Shoot SGT-FN-1B2; August 16, 2007
- WO 01127995; RCIC-DT-1Oil Replacement and Coupling Repack; August 27, 2007
- WO 01113918; Detailed Inspection of Circuit Breaker E-CB-S/3; September 11, 2007

The inspectors completed six samples.

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

.1 Forced Outage FO-07-02 (June 28 to June 30, 2007)

a. Inspection Scope

The inspectors reviewed the following risk significant refueling items or outage activities 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 outage activities.

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 below listed surveillance activities 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.

- WO 01139196; PPM 2.11.5; Floor Drain System; Revision 32; July 3, 2007
- WO 01131029; ESP-B02B-A101; 12 Month Battery Inspection of 24 VDC E-B0-2B; Revision 5; July 24, 2007
- WO 01134354; OSP-HPCS/IST-Q701; HPCS System Operability Test; August 15, 2007
- WO 01135137; OSP-CCH/IST-M701; Control Room Emergency Chiller System A Operability; Revision 21; September 7, 2007

The inspectors completed four samples including: two routine surveillance tests; one inservice test; and one reactor coolant system leakage surveillance tests.

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 temporary modification 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; and (4) verified that appropriate safety evaluations were completed. The inspectors verified that licensee identified and implemented any needed corrective actions associated with temporary modifications.

- TMR 07-017; Connect temporary tubing to allow an alternate hydrogen feed to the main generator via the hydrogen dryer skid (for main generator rotor cooling) until an obstruction can be removed in R-19; September 24, 2007

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

For the below listed drills and simulator-based training evolutions contributing to Drill/Exercise Performance and Emergency Response Organization Performance Indicators, the inspectors: (1) observed the training evolution to identify any weaknesses and deficiencies in classification, notification, and Protective Action Recommendations (PAR) 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.

- Anticipatory transient without a scram, followed by a loss of coolant accident with drywell pressure response not consistent with a loss of coolant accident; August 28, 2007

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

a. Inspection Scope

Cornerstone: Mitigating Systems

The inspectors sampled licensee submittals for the mitigating system performance indicators listed below for the period from the fourth quarter 2006 through the third quarter 2007. To verify the accuracy of the data reported during that period, definitions and guidance contained in NEI 99-02, "Regulatory Assessment Indicator Guideline," Revision 5, were used to verify the basis in reporting for each data element. The inspectors reviewed the data the licensee used to generate the basis document unavailability and unreliability values. The licensee entered the values into a spreadsheet which was used to perform various calculations. The inspectors also used the following licensee source documents to verify the validity of the input data, Control Room Logs, Surveillance Test Procedures and Maintenance Procedures. The inspectors looked at the mitigating system performance indicators for the following systems:

- High Pressure Coolant Injection

- Heat Removal System
- Emergency AC Power System
- Residual Heat Removal System

The inspectors completed four samples.

b. Findings

No findings of significance were identified. The inspectors concluded that the licensee is monitoring, collecting and entering the appropriate data in accordance to the prescribed guidance.

4OA2 Identification and Resolution of Problems (71152)

.1 Review of Items Entered into the Corrective Action Program:

a. Inspection Scope

As required by Inspection Procedure 71152, Identification and Resolution of Problems, and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed screening of all items entered into the licensee's corrective action program. This was accomplished by reviewing the description of each new corrective action document and periodically attending daily management meetings.

b. Findings

No findings of significance were identified.

.2 Annual Sample - Review of Closed Operability Evaluations

a. Inspection Scope

The inspectors reviewed a sampling of prompt operability evaluations that had been closed by Energy Northwest to assess the basis for closure to ensure that there were no latent operability issues for the associated equipment. Additionally, the inspectors sampled other issues documented in the station's corrective action program which were assigned either an apparent cause or a root cause but for which no prompt operability determination was documented to verify the justification for not documenting a prompt operability determination.

The inspectors completed one sample.

b. Findings and Observations

No findings or observations of significance were identified.

.3 Annual Sample - Control of Level 1 Controlled Documents

a. Inspection Scope

On August 29, 2007, the inspectors reviewed Energy Northwest condition reports specifically related to maintaining procedures current associated with safety-related equipment (Level 1 procedures) from August 2005 through July 2007. The inspectors concluded that there was no programmatic problems associated with maintaining Level 1 procedures current.

The inspectors completed one sample.

b. Findings and Observations

No findings or observations of significance were identified.

4OA3 Event Followup (71153)

.1 Reactor Scram due to Tripped Condensate Booster Pump

On June 28, 2007, the reactor automatically scrammed on low reactor water level due to an unexpected trip of a condensate booster pump while the unit was at 70 percent power. The condensate booster pump tripped while operators were manually transferring the pump's duplex oil filter to the standby filter. At the time of the pump trip, only two of the three condensate booster pumps were in operation. As a result of the trip, only one condensate booster pump remained in operation and as a result the reactor feedwater pumps tripped on low suction pressure causing the lowering reactor water level. The inspectors also observed reactor operators actions in response to the reactor scram and senior reactor operators evaluation of plant conditions and oversight of the reactor operators to ensure that operators were adhering to plant procedures. See Section 4OA3.2 of this inspection report for a discussion of an associated self-revealing finding.

.2 (Closed) LER 05000397/2007-004-00; Reactor Scram due to Tripped Condensate Booster Pump

a. Inspection Scope

On June 28, 2007, the reactor automatically scrammed on low reactor water level due to an unexpected trip of a condensate booster pump while the unit was at 70 percent power. The condensate booster pump tripped while operators were manually transferring the pump's duplex oil filter to the standby filter. At the time of the pump trip, only two of the three condensate booster pumps were in operation. As a result of the trip, only one condensate booster pump remained in operation and as a result the reactor feedwater pumps tripped on low suction pressure causing the lowering reactor water level. The inspectors evaluated this LER to determine if any violations of regulatory requirements occurred. This LER is closed.

The inspectors completed one sample.

b. Findings

Introduction. A self-revealing finding was identified for the failure to adhere to operations expectations and standards as provided in Operations Instruction OI-09, "Operations Standards and Expectations," Revision 12, an operations department instruction. As a result, an operating crew failed to make a conservative decision regarding transfer of a condensate booster pump lube oil duplex oil strainer, resulting in an inadvertent trip of the condensate booster pump and a plant scram. A crosscutting aspect in human performance was also identified.

Description. On June 28, 2007, with the facility operating at 70 percent power with Condensate Booster Pump 2A (COND-P-2A) out-of-service, a low oil pressure trip of COND-P-2B occurred during a swap of the pump's oil filter bank. The oil filter bank was swapped by an equipment operator with direction from control room staff after the equipment operator had noted that the differential pressure across the filter bank was 22 psid which was approximately 10 times the expected value. As a result of the trip of COND-P-2B with COND-P-2A already out-of-service, both operating reactor feedwater pumps tripped on low suction pressure causing a subsequent reactor trip on low reactor vessel water level.

Energy Northwest conducted a root cause evaluation as documented in PER 207-0261 and identified the following root causes:

1) Less than adequate configuration control was established or maintained for the COND-P-2B lube oil filter valves. Investigation of the valve configuration identified a "break before make" configuration for the as-found condition of the COND-P-2B lube oil filter transfer valves. This configuration contributed in the loss of oil pressure to the pump as the oil filter bank was swapped. The correct configuration was supposed to be "make before break" to ensure that lube oil flow and pressure was maintained during a transfer of the in-service oil filter.

Contributing to the incorrect as-found configuration was the fact that the transfer valves were designed by the manufacturer to be configured in either manner depending on the needs of the application for which the valves were installed. Adding to this was that historical maintenance and installation instructions did not specify which configuration the transfer valves should be installed or maintained. Energy Northwest concluded that the "break before make" configuration may have been in existence since initial installation considering that interviews with former and experienced equipment operators indicated that "tribal knowledge" was passed down that the valves were "break before make" and therefore should not be operated with the condensate booster pump in operation.

2) Less than adequate decision making process was employed by the operating crew. Investigation of the crew's performance identified that although the basis for the crew's decision to swap the filter while COND-P-2B was operating was reasonable and appeared at the time to be a successful path, it relied on

inaccurate assumptions and failed to accurately assess risk. Specifically, the operating crew incorrectly assumed that the high differential pressure was caused by a defective filter or had been installed incorrectly. Additionally, the only relevant procedural direction associated with a condensate booster pump oil filter high differential pressure was provided in an alarm response procedure which referenced swapping the filter if differential pressure was greater than 20 psid per procedure SOP-COND-OPS, “Main Condensate System Operations,” Revision 3. However, SOP-COND-OPS did not provide any procedural steps, guidance, or precautions for swapping condensate booster pump lube oil filters.

Contributing to the operating crew’s decision to swap the oil filters was that COND-P-2A was already out of service and that a loss of COND-P-2B due to a loss of lube oil pressure as a result of a fouled or incorrectly installed oil filter may cause an inadvertent plant scram due to a loss of reactor feedwater. However, the operating crew did not trend bearing oil pressure or filter differential pressure to determine if pump operating conditions were abnormal but stable or deteriorating. Another concern was that a high differential pressure might cause a filter failure or was an indicator of a failing filter, with the potential for damaging pump components. However, available indications were that the oil pressures were stable and bearing temperature was not excessive, which supported postponing action until COND-P-2A was back in service.

The inspectors reviewed Operating Instruction OI-09, “Operations Standards and Expectations,” Revision 12, and noted the following relevant standards:

- Section 4.2.3 provided examples of situations that require conservative decision making including unclear procedure steps.

- Section 4.2.4 provided to avoid hasty actions and that there are few time critical actions which require immediate response.

- Section 4.2.8 provided that when the control room is faced with time-critical decisions to question, verify and validate available information.

The inspectors concluded that contrary to the provisions in OI-09: 1) the operating crew swapped oil filters based on direction provided in an alarm response procedure which referenced transferring oil filters via a procedure which did not provide any relevant direction or guidance on swapping the filters, therefore making a decision to transfer the oil filters with unclear or no procedure steps; and 2) the operating crew swapped the oil filters under a perceived sense of urgency although pump operating parameters were stable and not degrading, therefore making a decision to swap the oil filters without questioning, verifying and validating available information.

It should be noted that although local lube oil filter gage indications, as read by the equipment operator, indicated a high differential pressure, an associated control room annunciator did not alarm nor were there any other indications of a high lube oil filter differential pressure. Additionally, local lube oil flows and bearing temperatures were normal.

Analysis. The performance deficiency associated with the finding is Energy Northwest's failure to implement the standards and guidance provided in OI-09 in the decision making process to swap COND-P-2B's oil filters. As a result, the operating crew failed to make a conservative decision regarding the swap of the oil filters while the pump was in operation causing a loss of the pump and a resultant plant scram. This finding was more than minor because it was a human performance issue which affected the initiating events cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Additionally, the finding was more than minor because it was also a human performance issue which affected the mitigating systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using NRC Manual Chapter 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations," dated March 23, 2007, the inspectors conducted a Phase 1 screening and determined that since the performance deficiency affected both the initiating events and mitigating systems cornerstones that a Phase 2 evaluation was required. The inspectors consulted with a regional SRA and determined that a phase 2 evaluation was not appropriate for the circumstances associated with this finding because the performance deficiency was predicated on inappropriate operator actions at a reduced power level and not on any specific equipment deficiency. A Phase 3 analysis was performed by the senior reactor analyst. Key assumptions included the probability of MSIV closure upon a loss of feed, operator recovery of the power conversion system following an MSIV closure, and the effect of containment failure on HPCS functionality. The core damage frequency result was less than 1.0E-6/yr. The initial screening of delta-LERF was slightly greater than 1.0E-7/yr., but a refinement of this result yielded a value less than 1.0E-7/yr. Consequently, the significance of the finding was determined to be of very low risk significance (Green). A cross-cutting aspect in human performance with a component of decision-making (H.1.b) was identified because Energy Northwest operations staff failed to utilize conservative assumptions in the decision to swap the COND-P-2B oil filter bank with the pump in service.

Enforcement. No violations of NRC requirements were identified since the affected components, condensate booster pumps and reactor feedwater pumps, are non-safety related components (FIN 05000397/2007004-01; Failure to Adhere to Operations Standards and Expectations).

.3 (Closed) LER 05000397/2007-003-00; Technical Specification Required Shutdown due to Inoperable AC Electrical Power Subsystem

On April 8, 2007, Columbia Generating Station conducted a Technical Specification required shutdown due to power fluctuations on critical instrument power panel E-PP-8AA. The power fluctuations on the power panel occurred during the replacement of transformer E-TR-IN/2, when the ground reference for the power panel was unknowingly removed. The resulting power fluctuations resulted in the power panel being declared inoperable causing Columbia Generating Station to enter TS 3.8.7.A. Prior to exceeding the allowed outage time in TS 3.8.7.A, Energy Northwest decided to initiate a reactor shutdown to address the power fluctuations in the power panel. Energy Northwest determined the cause of the event to be a less than optimal design that introduced a vulnerability via the unnecessary routing of the grounded neutral wire for E-PP-8AA through E-TR-IN/2. See IR 05000397/2007003, Section 4OA3.1, for a discussion of the self-revealing NCV associated with this issue. The inspectors completed a review of the LER and did not identify any other violations of regulatory requirements or findings. Energy Northwest documented the issue in PER 207-0163. This LER is closed.

The inspectors completed one sample.

4OA5 Other Activities

.1 Institute of Nuclear Power Operations (INPO) Plant Assessment Report Review

a. Inspection Scope

On August 7, 2007, the inspectors completed a review of the final report for the INPO plant assessment of Columbia Generating Station conducted in December 2006. The inspectors reviewed the report to ensure that issues identified were consistent with the NRC perspectives of licensee performance and to verify if any significant safety issues were identified that required further NRC follow-up.

b. Findings

No findings of significance were identified.

4OA6 Meetings, Including Exit

Exit Meeting Summary

On October 1, 2007, the resident inspectors presented the inspection results to Mr. T. Lynch and other members of Energy Northwest staff, who acknowledged the findings. The inspectors asked Energy Northwest whether any of the material examined during the inspection should be considered proprietary. No proprietary information was identified.

4OA7 Licensee Identified Violations

The following violation of very low safety significance (Green) was identified by the licensee and is a violation of NRC requirements which meets the criteria of Section VI of the NRC Enforcement Policy for being dispositioned as an NCV.

- TS 5.4.1.a requires that the written applicable procedures contained in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978, shall be established, implemented, and maintained. Regulatory Guide 1.33, “Quality

Assurance Program Requirements (Operation)," Revision 2, Appendix A, Section 9(a), requires that maintenance that can affect the performance of safety-related equipment should be performed in accordance with written procedures that are appropriate to the circumstance. Contrary to this, on August 23, 2007, while performing a surveillance test on RHR-PS-16C, operators calibrated RHR-PS-16C outside of the allowable range required by technical specifications because the surveillance procedure provided incorrect calibration data. This caused a permissive signal to the automatic depressurization system to be inoperable. The cause of the inadequate surveillance procedure was due to a recent revision to the surveillance procedure which inadvertently incorporated the incorrect calibration data. This event is documented in the licensee's corrective action program as CR 2-07-07994. This finding is of very low safety significance because it did not result in the automatic depressurization system not being able to perform its safety function.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Energy Northwest

D. Atkinson, Vice President, Nuclear Generation
D. Coleman, Manager, Performance Assessment and Regulatory Programs
L. Cortopassi, Manager, Operations
G. Cullen, Licensing Supervisor, Regulatory Programs
J. Frisco, General Manager, Engineering
S. Gambhir, Vice President, Technical Services
T. Lynch, Plant General Manager
J. Parrish, Chief Executive Officer
F. Schill, Licensing
M. Shymanski, Manager, Radiation Protection
C. Whitcomb, Vice President, Organizational Performance and Staffing

NRC Personnel

M. Hayes, Reactor Engineer
R. Cohen, Resident Inspector
Z. Dunham, Senior Resident Inspector

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

None.

Opened and Closed

05000397/2007004-01	FIN	Failure to Adhere to Operations Standards and Expectations (Section 4OA3.2)

Closed

05000397/2007-003-00	LER	Technical Specification Required Shutdown due to Inoperable AC Electrical Power Subsystem (Section 4OA3.3)
05000397/2007-004-00	LER	Reactor Scram due to Tripped Condensate Booster Pump (Section 4OA3.2)

Discussed

None.

PARTIAL LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection

Procedures

ABN-ASH; ASH FALL; Revision 7

Section 1R04: Equipment Alignment

Procedures

SOP-DG1-STBY; Emergency Diesel Generator (DIV 1) Standby Lineup, Revision 6

ABN-CR-EVAC; Control Room Evacuation and Remote Cooldown; Revision 10

SOP-DG3-STBY; High Pressure Core Spray Diesel Generator Standby Lineup; Revision 7

Drawings and Diagrams

M512-2; Revision 32

M520; Flow Diagram HPCS and LPCS Systems Reactor Building; Revision 95

M524-1; Flow Diagram Standby Service Water System Reactor, Radwaste, D.G. Bldg's and Yard; Revision 109

M512-1; Flow Diagram Diesel Oil & Miscellaneous Systems Diesel Generator Building; Revision 40

M551; Flow Diagram HVAC Circ. & M U Water, S.W. Pump Houses, & Diesel Generator Bldg.; Revision 56

Work Orders and Work Requests

WO 01111490	WO 01120222	WR 29060923

Corrective Action Documents

CR 2-07-06358	CR 2-07-06356	CR 2-07-06339	CR 2-07-06312
CR 2-07-06250	CR 2-07-05873	CR 2-07-05835	CR 2-07-05562
CR 2-07-05452	CR 2-07-05324	CR 2-07-05318	CR 2-07-05180

Miscellaneous

Check Valve Condition Monitoring Program Document; Revision 0

Section 1R05: Fire Protection

Procedures

FPP-1.6; Combustible Loading Calculation Control; July 22, 2004

Final Safety Analysis Report; Appendix F

National Fire Protection Association NFPA-10, 1984 Revision

Miscellaneous

Columbia Generating Station Final Safety Analysis Report; Appendix F; Amendment 57

Columbia Generating Station Pre-Fire Plans; Revision 3

Section 1R07: Heat Sink Performance

Procedures

SOP-SW-START, Standby Service Water System Start; Revision 2

PPM 1.5.9, Plant Performance Monitoring Program; Revision 8

Drawings and Diagrams

M521-1 Flow Diagram, Residual Heat Removal System Loop A; Revision 102

M521-2 Flow Diagram, Residual Heat Removal System Loop B; Revision 104

M524-1, Flow Diagram, Standby Service Water System; Revision 110

M524-2, Flow Diagram, Standby Service Water System; Revision 101

Work Orders and Work Requests

WO 01109770

Miscellaneous

FSAR 6.2.2, Residual Heat Removal Containment Heat Removal System; Amendment 59

FSAR 9.2.7, Standby Service Water System; Amendment 58

Calculation ME-02-92-231; Calculation For Evaluation OF Heat Exchanger Performance Data; Revision 1

Calculation ME-02-92-241; Calculation For DCW Heat Exchanger 1A1 and 1A2 Performance Data Monitoring data Evaluation; Revision 1

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

Section 1R11: Licensed Operator Requalification

Miscellaneous

LR001832; Operations Re-qualification Training; Revision 0

LR001832; Drill, Exercise, and Actual Events Opportunity Evaluation; Dated September 13, 2007

Section 1R12: Maintenance Effectiveness

Procedures

PPM ISP-FDR/EDR-M401; Drywell Sump Flow Monitors - CFT; Revision 5

Work Orders and Work Requests

WO 01133297	WO 01136813	WO 01125815	WO 01133505
WO 01140780			

Corrective Action Documents

CR 2-07-07399	CR 2-07-07521	CR 2-07-08459	PER 207-0331

Miscellaneous

Columbia Generating Station Maintenance Rule Scoping Matrix; Revision 17

Maintenance Rule Expert Panel Meeting Minutes; September 5, 2007

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Procedures

PPM 10.25.179; Flexible and Rigid Link Removal Inspection and Installation; Revision 1

Work Orders and Work Requests

WO 01139198	WO 01130651	WO 01139000

Corrective Action Documents

CR 2-07-07521	CR 2-07-06410

Miscellaneous

07-0326; Barrier Impairment Permit; August 17, 2007

07-0315; Barrier Impairment Permit; July 28, 2007

Section 1R15: Operability Evaluations

Procedures

PPM OSP-WMA-M701; Control Room Emergency Filtration system A Operability; Revision 5

PPM 8.3.406; Control Room Exhaust damper Test; Revision 0

PPM 1.3.57; Barrier Impairment; Revision 21

PPM 3.1.2; Reactor Plant Startup; Revision 68

PPM SOP-SGT-START; Standby Gas Treatment Start; Revision 3

TSP-RB-B501; Reactor Building (Secondary Containment) Drawdown/Leakage Functional Test; Revision 4

ABN-SGT-TEMP/RAD; Standby Gas Treatment Charcoal High Temperature/Radiation; Revision 0

Drawings and Diagrams

M530-1; Flow Diagram Nuclear Boiler Recirculation System; Revision 81

Work Orders and Work Requests

WO 01139354	WR 29062784	WO 01137719	WO 01138364
WO 01138357	WO 01107387	WO 01107614	

Corrective Action Documents

CR 2-07-07349	CR 2-07-07347	CR 2-07-07595	PER 207-0270
CR 2-07-06577	CR 2-07-06618	PER 207-0319	

Miscellaneous

Night Order 863; July 7, 2007

ME-02-05-01; Determination of Acceptable Oil Leakage Rates from Pump Motors; Revision 1

Section 1R19: Post Maintenance Testing

Procedures

PPM 10.25.13; Westinghouse Medium Voltage Circuit Breakers; Revision 27

SOP-ELEC-4160V-OPS; 4160 Volt AC Electrical Power Distribution System Operation; Revision 1

PPM 2.7.1A; 6900 Volt and 4160 Volt AC Electrical Power Distribution System; Revision 16

PPM 2.7.13; AC Electrical Breaker Racking

Drawings and Diagrams

EWD-9E-049; Electrical Wiring Diagram RHR System MOV RHR-V-48; Revision 16

M825; HVAC 501 and 507 Radwaste and Control Buildings; Revision 32

Work Orders and Work Requests

WO 01113918	WO 01139000	WO 01139245	WO 01137144

Corrective Action Documents

CR 2-07-07349

Miscellaneous

ME-02-83-64; Calculation for Verification of Flow Rates on WMA Air Handling Units 51A and 51 B

LCO INOP Sheet Log Number 11435; Dated July 28, 2007

Section 1R20: Refueling and Other Outage Activities

Procedures

PPM 1.16.8A; Outage Risk Management; Revision 4

PPM 3.3.1; General Operating Procedures; Reactor Scram; Revision 48

PPM 3.1.1; Master Startup Checklist; Revision 35

Work Orders and Work Requests

WO 01139000

Section 1R22: Surveillance Testing

Procedures

PPM ESP-B02B-A101; 12 Month Battery Inspection of 24 VDC E-B0-2B; Revision 5

PPM 2.11.5; System Operating Procedures; Floor Drain System; Revision 32

OSP-CCH/IST-M701; Control Room Emergency Chiller System A Operability; Revision 21

Drawings and Diagrams

Component Classification Evaluation Record CER C91-0200

Work Orders and Work Requests

WO 01139196	WO 01131029	WR 29062575	WR 29062577

Corrective Action Documents

CR 2-07-07628	CR 2-07-07228

Miscellaneous

LCO Log Number 11448; Dated September 8, 2007

LCO Log Number 11428; Dated July 24, 2007

FSAR 9.4.1; Amendment 54

Section 1R23: Temporary Plant Modifications

Procedures

PPM SOP-H2/CO2-OPS; H2/CO2 System Operations; Revision 8

Drawings and Diagrams

M957; Flow Diagram Generator Hydrogen System Turbine Generator Building; Revision 21

Miscellaneous

Temporary Modification Request TMR 07-017; Connect Temporary Tubing To Provide An Alternate Hydrogen Feed to the Hydrogen dryer Skid While The Line Is Blocked; Dated September 17, 2007

Section 4OA1: Performance Indicator Verification

Procedures

NEI 99-02; Regulatory Assessment Performance Indicator Guideline, Revision 4

NEI 99-02; Regulatory Assessment Performance Indicator Guideline, Section F; Revision 5

WNP-2 Performance Indicator Report Data; Mitigating System Unavailability; August 2007

Miscellaneous

Technical Specification Inoperable Equipment/LCO/RFO Status Sheet

LCO Log Number 11460	LCO Log Number 11293	LCO Log Number 11267
LCO Log Number 11162	LCO Log Number 11010	LCO Log Number 11984
LCO Log Number 11778	LCO Log Number 11261	LCO Log Number 10086
LCO Log Number 11394	LCO Log Number 11020	LCO Log Number 11913
LCO Log Number 11830	LCO Log Number 11598	LCO Log Number 11538
LCO Log Number 11189	LCO Log Number 11414	LCO Log Number 11447
LCO Log Number 11002	LCO Log Number 11813	LCO Log Number 11794
LCO Log Number 11790	LCO Log Number 11628	LCO Log Number 11477
LCO Log Number 11439	LCO Log Number 11415	LCO Log Number 11411
LCO Log Number 11408	LCO Log Number 11218	LCO Log Number 11173
LCO Log Number 11118	LCO Log Number 11111	LCO Log Number 11092
LCO Log Number 11084	LCO Log Number 11049	LCO Log Number 11016

Section 4OA2: Identification and Resolution of Problems

Procedures

PPM 1.3.66; Operability and Functionality Evaluation; Revision 8

ABN-FIRE, Fire; Revision 13

ABN-CR-EVAC, Control Room Evacuation and Remote Cooldown; Revision 10

SWP-DOC-01, Document Control; Revision 3

SWP-PRO-02, Preparation, Review, Approval and Distribution of Procedures; Revision 18

Corrective Action Documents

CR 2-06-00210	CR 2-05-06555	CR 2-05-07278	CR 2-06-01189
CR 2-06-08472	CR 2-07-04573	CR 2-07-03657	CR 2-07-08220
CR 2-07-08275	CR 2-05-05501	CR 2-05-05863	CR 2-05-06865
CR 2-05-07284	CR 2-06-00089	CR 2-06-00862	CR 2-06-03889
CR 2-06-09365	CR 2-07-01959	CR 2-07-03383	CR 2-07-00660
CR 2-07-06625	CR 2-07-08068	CR 2-06-00639	CR 2-06-01314
CR 2-06-02029	CR 2-06-03301	CR 2-06-06607	PER 207-0327
PER 205-0122	PER 207-0135	PER 205-0348	PER 205-0199
PER 206-0109	PER 206-0668		

Columbia Generating Station
Phase 3 Analysis
Reactor Trip Caused by Inappropriate Maintenance on Condensate System

Performance Deficiency

While Condensate Booster Pump 1A was out of service, maintenance was performed on Condensate Booster Pump 1B (swapping in-service oil filters). This maintenance carries a high risk for the tripping of the booster pump. The pump tripped and a trip of the reactor feed pumps and a reactor trip followed. An MSIV closure occurred on a Level 2 signal. No other significant equipment failed.

<u>Assumptions</u>

1. This event is considered to be the result of an inadequate approach to practicing risk-informed maintenance. The deficiency can be considered to have been in existence for a period of one-year, but would likely have resulted in at most one reactor trip during that time, because it is likely that changes to the maintenance approach would ensue following the first event. Therefore, the delta-CDF of the finding can be considered equivalent to the CCDP of a reactor trip with the observed occurrences.

   The design of the oil filter for Condensate Booster Pump 1B is different than that for Pumps 1A and 1C in that the swapping of filters results in a break before make situation. This implies that the 1B pump would trip whenever operators swap the oil filters while it is running. Based on this information, the analyst concluded that using a 1.0 event frequency as described above is correct.

2. Recovering the power conversion system, if necessary, following the trip and closure of the MSIVs was available to operators if other mitigating systems had failed. This would have entailed re-opening the MSIVs, re-establishing steam condensing in the main condenser, and starting the necessary pumps to inject into the reactor vessel. The analyst used the SPAR-H method to calculate a failure probability, with the following result:

	Diagnosis (0.01)	Action (0.001)
Available Time	Nominal	Nominal
Stress	High (2.0)	High (2.0)
Complexity	Nominal	Moderately Complex (2.0)
Total	2E-2	4E-3
Overall Total	2.4E-2	

3. Historically, there have been three loss of feed reactor trips at Columbia. On two of these occasions, the MSIVs closed; on one occasion, operators were able to control level such that the MSIVs did not close. The analyst used this information to set the probability of an MSIV isolation to 2/3.

4. The SPAR model contained a basic event, CFAILED01, containment failure causes loss of HPCS injection, with a base case value of 1/3. This was determined to be an over-conservatism because of the small range of containment failure locations that would affect HPCS operation. To account for this conservatism, the analyst changed the value of CFAILED01 to 0.1.

5. Although Condensate Booster Pump 1B tripped on momentary low oil pressure, it was still available and therefore was not changed from the base case in the SPAR model.

Analysis

The Columbia SPAR model, Revision 3.31, was used with a truncation of E-12. Average test and maintenance was assumed because the event could have occurred at any time during the operating cycle.

Within SAPHIRE, the following change set was constructed:

IE-TRANS (general plant transient) was set to a probability of 1.0
CDS-MDP-TM-B1A (Condensate Booster Pump 1A in test and maintenance) set to a probability of 1.0
PCS-XHE-XL-LTTRAN (Operator Fails to recover PCS in the long-term) set to 2.4E-2
MSS-MSV-OC-STEAM (Steam valves fail to remain open) set to 2/3
CFAILED01 (Containment failure causes loss of HPCS injection) to 0.1

The /CND top event tree quantification defaults to 1.0 as a small-event approximation. However, with the change set used, CND quantifies to 6.691E-1; therefore /CND should receive a value of 3.309E-1. This correction applies to Transient sequences 7 and 8.

Only transient sequences were quantified. The current case result was 8.527E-7. When Sequences 7 and 8 are corrected as discussed above, the result is 7.404E-7, which in this instance is identical to the CCDP. The dominant cutsets involved a failure to control high pressure injection sources and a failure to depressurize the reactor.

External events were not additive to the significance of this finding. IMC 0609, Appendix H, was reviewed to consider the possibility of a large early release. For a Mark II containment, contribution to large early release occurs with high pressure and ATWS sequences. The following table presents the results:

Transient Sequence Number	Type	CDF contribution	LERF Factor	LERF frequency
8	High Pressure	3.53E-8[1]	0.3	1.06E-8
12	High Pressure	0	0.3	0
14	High Pressure	4.87E-8	0.3	1.46E-8
31	High Pressure	2.01E-8	0.3	6.03E-9
49	High Pressure	4.07E-7	0.3	1.22E-7
52 (all)	ATWS	3.60E-8	0.4	1.44E-8
Total LERF				1.68E-7

1. This is the corrected sequence result for the /CND correction.

The calculated LERF of 1.68E-7/yr. indicated a WHITE significance to the finding. The analyst contacted the NRR containment specialist to refine the 0609, Appendix H, result since it is essentially a screening value. Information developed for a Mark I containment plant (Brunswick), but which is applicable to Mark II containments as well, suggests that approximately 95 percent of what is typically characterized as a high-pressure sequence will involve an automatic depressurization by either temperature-induced creep rupture or a stuck open SRV such that the vessel breach will actually occur at low pressure. Based on this information, the NRR specialist and the analyst agreed that the LERF associated with this finding can be considered to be less than E-7/yr. and that the finding should be characterized as having a green significance.