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

February 14, 2005

EA 04-0192

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 05000397/2004005

Dear Mr. Parrish:

On December 31, 2004, 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 January 6, 2005, with yourself 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 and three self-revealing findings. All of these findings were determined to involve violations of NRC requirements. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these four findings as noncited violations (NCVs) 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.

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).

Sincerely,

/RA/

William B. Jones, Chief
Project Branch E
Division of Reactor Projects

Docket: 50-397
License: NPF-21

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NRC Inspection Report
05000397/2004005

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	50-397
License:	NPF-21
Report:	05000397/2004005
Licensee:	Energy Northwest
Facility:	Columbia Generating Station
Location:	Richland, Washington
Dates:	September 24 through December 31, 2004
Inspectors:	Z. Dunham, Senior Resident Inspector, Project Branch E, DRP R. Cohen, Resident Inspector, Project Branch E, DRP V. Gaddy, Senior Project Engineer, Project Branch E, DRP D. Stearns, Project Engineer, Project Branch E, DRP W. McNeill, Reactor Inspector, Engineering Branch C. Paulk, Senior Reactor Inspector, Engineering Branch
Accompanying Person:	N. Morgan, Reactor Inspector, Engineering Branch
Approved By:	W. B. Jones, Chief, Project Branch E, Division of Reactor Projects
ATTACHMENT:	Supplemental Information

CONTENTS

SUMMARY OF FINDINGS

IR05000397/2004005; 9/24/2004 - 12/31/2004; Columbia Generating Station. Adverse Weather Protection, Personnel Performance During Nonroutine Evolutions, Surveillance Testing, and Other.

The report covered a 13-week period of inspection by the resident inspectors, engineering inspectors. Four Green noncited violations and one unresolved item were identified. The significance of most findings is indicated by their color (Green, White, Yellow, 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. The NRC identified a noncited violation of Technical Specification 5.4.1.a associated with an inadequate procedure. Procedure ABN-ASH, Ash Fall, which identified Energy Northwest actions in the event of a volcanic eruption in the Pacific Northwest, was inadequate in that it defined design basis ash fall conditions at the site which could not be readily measured. In the event design basis ash fall conditions were to occur, Procedure ABN-ASH directed reducing power, scramming the reactor, and cooling down to cold shutdown. Without readily measurable criteria, the operators may not recognize design basis ash fall conditions and therefore may not initiate a reactor shutdown and cooldown in accordance with Procedure ABN-ASH prior to the degradation of balance of plant equipment. A human performance crosscutting aspect was identified for the inadequate procedure which could not be readily implemented as written. A problem identification and resolution crosscutting aspect was identified for the issue not being documented in the corrective action program until prompted by the inspectors. The immediate corrective actions that were taken included revising Procedure ABN-ASH to establish readily measurable criteria indicative of the site reaching design ash fall conditions.

  This finding was greater than minor because it involved a procedure quality 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 power operations. The finding was evaluated using Manual Chapter 0609, Significance Determination Process, Phase 1 worksheet. The finding was determined to be of very low safety significance (Green) because it was not associated with a loss of coolant accident initiator, it did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions were not available, and it did not increase the likelihood of a fire or internal/external flood (Section 1R01).

Cornerstone: Barrier Integrity

- Green. A self-revealing noncited violation of Technical Specification 5.4.1.a was identified for the failure to initiate a manual reactor scram when an equipment operator inadvertently scrammed an individual control rod from position 48 to 14. Abnormal Condition Procedure ABN-ROD, Control Rod Faults, Revision 6, required a manual scram for one or more control rods scrammed but do not indicate full-in. This finding had human performance crosscutting aspects related to the communications between the control room and the operator at the respective hydraulic control unit and for the failure to follow Procedure ABN-ROD and manually scram the reactor. Corrective actions included plant management reinforcing the requirement to immediately scram the reactor in the event of an inadvertently scrammed control rod which does not fully insert. The procedure was subsequently revised to rapidly reduce core flow as was done by the operations in response to this event.

  This issue affected the barrier integrity cornerstone and is greater then minor because it affects the fuel cladding barrier since failing to scram with a control rod not fully inserted increased the potential for fuel cladding damage. This issue was evaluated using NRC Manual Chapter 0609, Significance Determination Process, Phase 1 Worksheet, under the barrier integrity cornerstone Item 2, Fuel Barrier, and was determined to be of very low safety significance. A review of the thermal limits (nodes) for the adjacent fuel assemblies verified that no limits were exceeded (Section 1R14).

Cornerstone: Mitigating Systems

- Green. A self-revealing noncited violation of Technical Specification 5.4.1.a was identified for a technician's failure to follow a surveillance procedure. During the conduct of a surveillance test for the reactor core isolation cooling system the technician was directed by procedure to monitor voltage across two terminals, however, the technician inadvertently jumpered across the two terminals. This resulted in an unexpected isolation of the reactor core isolation cooling system for approximately two hours when an isolation signal was generated. This finding had human performance crosscutting aspects in that the technician failed to self-check and verify the configuration of the test equipment prior to use.

  This finding was greater than minor because it was a human performance 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. The safety significance associated with this performance deficiency was evaluated using the NRC Manual Chapter 0609, Significance Determination Process, Phase 1 Worksheet, under the mitigating system cornerstone. The finding was determined to be of very low safety significance 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 (Section 1R22).

- Green. A self-revealing noncited violation of Technical Specification 5.4.1.a and Procedure PPM 1.3.1, Conduct of Operations, was identified when a reactor operator failed to identify and communicate to the control room supervisor the reactor pressure vessel high trip annunciator following a reactor scram which occurred on July 30, 2004. An associated operating instruction also provides that during transient/emergency operating procedure implementation that alarms are promptly evaluated and operationally significant alarms are communicated by the operator to the control room supervisor. In addition, the annunciators flagged as potential emergency operating procedure entries are assessed by the operator and communicated to the control room supervisor as emergency operating procedure entry conditions including parameter, value, units, and trend. Human performance crosscutting aspects were identified for this finding involving the operator response to the annunciators and the lack of command and control within the control room that failed to promptly determine the cause for the reactor trip that was later considered in the emergency response managers decision to declare an Alert.

  This finding was greater than minor because the failure to properly acknowledge and address annunciators was a human performance error (postevent) 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. By acknowledging and resetting key annunciators prior to communicating key parameters, values and trends may not be appropriately considered for significance of mitigating system response, emergency operating procedure entry conditions as well as emergency plan implementation. The finding was determined to be of very low risk significance because the finding did not involve a design or qualification deficiency, it did not represent a loss of safety function of a system or train, and was not risk significant because of seismic, fire, or flooding event (Section 4OA5.1).

B. Licensee Identified Violations

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

REPORT DETAILS

Summary of Plant Status:

The inspection period began with Columbia Generating Station at 100 percent power. The plant was maintained at essentially 100 percent power for the entire inspection period except for brief reductions in power to facilitate plant testing and maintenance.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

On September 26, 2004, the United States Geological Survey issued a Notice of Volcanic Unrest for Mount St. Helens, located in Washington State. Seismic activity at Mount St. Helens had changed significantly within the previous 24 hours which suggested an increased likelihood of a hazardous event. This included the possibility of a volcanic eruption which could produce ash clouds. In response to the potential for a volcanic eruption, the inspectors reviewed Energy Northwest's FSAR, Technical Specifications, and emergency procedures to determine the susceptibility of Columbia Generating Station to ash fall at the site. Additionally, the inspectors reviewed and walked down Abnormal Condition Procedure ABN-ASH, Ash Fall, Revision 2, which prescribed actions to be taken in the event of predicted or actual ash fall on site to evaluate the adequacy of the procedure and to ensure that actions could be performed as prescribed. The inspectors also reviewed design basis documents and requirements for the two safety significant systems listed below to determine the readiness of the systems to perform their design function in the event of ash fall at the site.

- Standby Service Water; November 12, 2004
- Emergency Diesel Generators; November 16, 2004

b. Findings

Introduction. A Green noncited violation (NCV) of Technical Specification 5.4.1.a was identified by the inspectors for an inadequate abnormal condition procedure. Procedure ABN-ASH prescribed Energy Northwest's response to ash fall on site. The procedure was determined to be inadequate because it did not provide readily measurable criteria by which the operators would shutdown the plant in the event of design basis ash fall at the site.

Description. During a review of Abnormal Condition Procedure ABN-ASH, Ash Fall, Revision 2, the inspectors noted that Section 4.4 prescribed steps to reduce reactor power, scram the reactor, and cooldown to cold shutdown per plant procedures once design basis ash fall conditions were met. The procedure defined the design basis ash fall as either 1) an ash cloud at an elevation of 40,000 feet or higher, which was expected to begin passing over the Columbia Generating Station site within two hours and drop ash for up to 20 hours, or 2) an ash fall rate exceeding 0.21 in/hr. Although plant design documents described these conditions as the design basis ash fall, the inspectors identified that Energy Northwest could not readily determine if the procedure criteria had been met. For example, the procedure did not prescribe how or where the ash fall rate should be measured nor was there any means established for the measurement. Additionally, control room staff were not able to readily determine if an ash cloud was at an elevation of 40,000 feet or higher. Initiating a plant shutdown once design basis ash fall conditions are met is important due to the increased likelihood of balance of plant equipment degradation which could upset plant stability and cause an automatic reactor scram. On October 1, 2004, Energy Northwest revised Procedure ABN-ASH to reflect ash fall design parameters which could be directly measured. Energy Northwest documented the concerns in Condition Report 2-04-06284 on November 12, 2004. The inspectors noted that although Energy Northwest took prompt corrective actions to address the identified concerns, the concerns were not documented in their corrective action program until prompted by the inspectors. A human performance crosscutting aspect was identified for the inadequate procedure which could not be readily implemented as written. A problem identification and resolution crosscutting aspect was identified for not documenting the issue in a condition report (CR 2-04-06284) until the inspectors addressed the issue.

Analysis. Procedure ABN-ASH, Ash Fall, Revision 2, was inadequate in that the design basis ash fall conditions, which were required to be met in Section 4.4, to initiate a plant shutdown could not be adequately monitored. This is a performance deficiency of greater than minor risk significance because the finding was a procedure quality issue that affected the initiating events cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during power operations. Without the ability to adequately monitor design basis ash fall conditions on site, the control room staff may not initiate a reactor shutdown and cooldown in accordance with Procedure ABN-ASH prior to the degradation of balance of plant equipment. The finding was evaluated using Manual Chapter 0609, Significance Determination Process, Phase 1 worksheet. The finding was determined to be of very low safety significance (Green) because it was not associated with a loss of coolant accident initiator, it did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions were not available, and it did not increase the likelihood of a fire or internal/external flood.

Enforcement. Technical Specification 5.4.1.a required, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Regulatory Guide 1.33, “Quality Assurance Program Requirements (Operation),” Appendix A, Section 6, required, in part, that specific procedures for combating emergencies, including acts of nature (i.e., volcanic eruption) be written. Contrary to this requirement from September 11, 2000, to October 1, 2004, Procedure ABN-ASH, was inadequate in that the means to determine whether design basis ash fall conditions were met, which were required to be met in Section 4.4, to initiate a plant shutdown, had not been established. Because the violation was of very low safety significance and has been entered into Energy Northwest's corrective action program, this violation is being treated as a noncited violation, consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 50-397/04-05-01, Inadequate Ash Fall Procedure). Energy Northwest documented this issue in their corrective action program as CR 2-04-06284. Immediate corrective actions included revising the procedure to establish measurable criteria to implement the abnormal condition procedure.

1R04 Equipment Alignments (71111.04)

a. Inspection Scope

The inspectors completed partial system walkdowns of the three safety-related systems listed below. The inspectors reviewed system drawings, the Final Safety Analysis Report, Technical Specifications, and operating procedures to establish the proper equipment alignment to ensure system operability. The walkdowns consisted of verifying the mechanical and electrical alignments for each of these systems.

- Residual Heat Removal Train C while LPCS surveillance test in progress; November 15, 2004
- High Pressure Core Spray Diesel Generator; November 29, 2004
- 250 VDC Battery and Associated Electrical Distribution; December 9, 2004

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Quarterly Walkdowns

a. Inspection Scope

The inspectors performed walkdowns of six fire protection areas to verify operational status and material condition of fire detection and mitigation systems, passive fire barriers, and fire suppression equipment. The inspectors reviewed Energy Northwest's implementation of controls for combustible materials and ignition sources in selected fire protection zones. The inspectors compared observed plant conditions against descriptions and commitments in the Final Safety Analysis Report, Section 9.5.1, "Fire Protection System," and Appendix F, "Fire Protection Evaluation." The fire areas inspected were:

- Fire Area RC-10; Main Control Room; November 30, 2004
- Fire Area RC-14; Division I Switchgear Room; December 13, 2004
- Fire Area R-6; Reactor Core Isolation Cooling Pump Room; December 13, 2004
- Fire Area R-18; Division II MCC Room; December 13, 2004
- Fire Area SW-1; Standby Service Water Pump House 1A; December 15, 2004
- Fire Area SW-2; Standby Service Water Pump House 1B; December 16, 2004

b. <u>Findings</u>

No findings of significance were identified.

1R06 <u>Flood Protection Measures (71111.06)</u>

.1 <u>External Flood Protection</u>

a. <u>Inspection Scope</u>

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 other credible flood sources.

b. <u>Findings</u>

No findings of significance were identified.

.2 <u>Internal Flood Protection</u>

a. <u>Inspection Scope</u>

During the week of December 12, 2004, the inspectors examined one area, the Service Water A building, which contained the Service Water Pump A and the High Pressure Core Spray Service Water Pump, to validate Energy Northwest's assumptions and design analysis for internal flood mitigation. The review included walkdowns of the building to verify material condition of door seals and sealed wall penetrations, and a verification of assumptions stated in the flooding calculations. Additionally, the inspectors examined the building for any additional sources of internal flooding which Energy Northwest's internal flooding calculations and analysis had not accounted.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

On November 9, 2004, the inspectors observed one licensed operator requalification training exam. The inspectors evaluated crew performance in terms of formality of communication, prioritization of actions, annunciator response and implementation of procedures. The inspectors also observed Energy Northwest's evaluation of the crew's performance to ensure that performance deficiencies were appropriately discussed and evaluated. Simulator fidelity was also evaluated by the inspectors.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed the three maintenance rule related issues and/or safety related systems listed below to evaluate Energy Northwest's assessment of availability and reliability of risk-significant systems, structures and components.

- High Pressure Core Spray Service Water System; Review of system performance compared against the maintenance rule program, December 14, 2004

- Drywell Floor Drain Valves and Associated Local Leak Rate Test Issues (FDR-V-3 and FDR-V-4); Effectiveness review of associated maintenance practices and applicability to the maintenance rule program, December 16, 2004

- Safety related chill water system service water rupture discs for the control room emergency chiller, CCH-CR-1A; Effectiveness review of selected maintenance issues and practices, December 9, 2004

The inspectors utilized the following documents for this inspection:

- TI 4.22, Maintenance Rule Program, June 19, 2001

- Columbia Generating Station Maintenance Rule Scoping Matrix, October 30, 2003
- NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, Revision 2
- Procedure 1.5.11, Maintenance Rule Program, Revision 6

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors selected two samples of planned and emergent maintenance tasks for evaluation. The evaluation consisted of reviewing Energy Northwest's assessment of plant risk for the activity, risk management and review of compensatory measures, where appropriate, and reviewing plant status to ensure that other equipment deficiencies did not adversely impact the planned risk assessment. The samples included:

- Standby Liquid Control Pump 1A maintenance outage; planned inspection and inoperability of valves FDR-V-3 and FDR-V-4; containment atmosphere control Train A maintenance outage; Week of October 27, 2004
- RHR-P-2A Breaker Inspection and Maintenance; November 1, 2004

b. Findings

No findings of significance were identified.

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

b. Inspection Scope

The inspectors followed up on a June 10, 2004, event in which a non licensed operator inadvertently scrammed Control Rod 46-19 while hanging a clearance tag. The inspectors evaluated the performance of control room operators following the event.

c. Findings

Introduction. A Green self-revealing noncited violation of Technical Specification 5.4.1.a was identified for the failure to manually scram the reactor in accordance with Abnormal Conditions Procedure ABN-ROD, Control Rod Faults, Revision 6, for an inadvertently scrammed individual control rod. This occurred when a nonlicensed operator inadvertently placed the test switches for Hydraulic Control Unit (HCU) 46-19 in the test position, scramming the associated control rod from position 48 to 14. The control rod was stopped at position 14 when the operator realized the mistake and placed the test switch back to normal.

Description. On June 10, 2004, a nonlicensed operator manipulated the single rod insert test switches for the scram pilot valves associated with HCU 46-19 during the process of hanging clearance tags on HCU 50-19. HCU 50-19 was located adjacent to HCU 46-19. With the test switches in “TEST”, HCU 46-19's scram pilot valves de-energized, allowing the associated scram valves to open and the control rod to insert. Once the nonlicensed operator recognized the mistake, he restored the test switch to “NORMAL”, which subsequently closed the scram valves prior to control Rod 46-19 fully inserting. This resulted in control Rod 46-19 settling at step 14 (partially inserted). The operating crew then entered Abnormal Condition Procedure ABN-ROD, Control Rod Faults. The operating crew assessed control Rod 46-19 as a mispositioned rod. Although, the blue scram lights had been lit during the short time that the associated HCU scram valves were open, the operating crew did not observe this condition. The lights were indicative of a control rod that had been scrammed (scram pilot valves opened); although, the scram was not initiated by the reactor protection system. The operators promptly reduced reactor power to 78 percent by reducing core flow. Since the control rod was assessed as having been mispositioned, the operators took actions to recover the rod and verify that core thermal limits had not been violated. No core thermal limits were exceeded during the event.

The inspectors reviewed Procedure ABN-ROD to determine if the actions taken by the operating crews were appropriate. Step 4.9 of Procedure ABN-ROD defined a mispositioned control rod as:

- A control rod left in a position other than the intended position and not identified/corrected before or during the confirmation step of the rod motion instructions.

- A control rod moved greater than two notches past its intended position.

- A control rod left in other than its intended position due to mechanical problems (low air pressure, blown fuses, etc.)

Control Rod 46-19 did not meet the first or second condition. There were no rod motion instructions for moving control Rod 46-19 and the operators had not intended to move control Rod 46-19.

Control Rod 46-19 did not meet the third condition for a mispositioned control rod. There were no mechanical problems involved. However, the control rod did meet the conditions established for a inadvertently scrammed rod requiring a manual reactor scram as specified in Section 3.2, Inadvertently Scrammed Individual Control Rods, of Procedure ABN-ROD. Specifically, one rod had scrammed and did not indicate full in. The inspectors reviewed Section 5.0, Bases, to Procedure ABN-ROD. The associated Bases for Section 3.2.1 identifies that a rod which has failed to fully insert has the potential to overpower a node resulting in fuel damage and a reactor SCRAM is required.

The operating crew did not associate the information provided in the field with control room indications. The initial report from the equipment operator that inadvertently moved the HCU 46-19 test switch was that he may have scrammed control Rod 46-19. The operating crew checked the rod worth minimizer and observed the insert error and that the control rod was now at position 14. The control rod was initially at position 48. When the equipment operator took the switch to TEST, inward rod motion began. When the switch was returned to NORMAL, rod motion stopped at position 14. When the rod motion was stopped by placing the TEST switch to NORMAL, the blue scram lights extinguished. No control room indications for a scrammed control rod were subsequently present and the operating crew concluded they had a mispositioned control rod, not a scrammed control rod. Although the HCU SCRAM blue indicating lights were not observed by the operators, enough information, including communication from the equipment operator that he may have inadvertently scrammed control Rod 46-19, was available to the operating crew to conclude that the control rod had been scrammed and that it was not fully inserted.

Since the rod was scrammed, Energy Northwest personnel should have followed Step 3.2.1 of Procedure ABN-ROD, which states in part, that if one or more control rods SCRAM, <u>but do not indicate full in,</u> THEN MANUALLY SCRAM the Reactor. The bases section of the procedure states that, "A rod which has failed to fully insert has the potential to overpower a node resulting in fuel damage and a Reactor SCRAM is also required." Although no fuel damage occurred by not scramming the reactor in this instance, the inspectors were concerned that if the operating crew did not scram the reactor under similar circumstances for a control rod located in a different region of the core that there may be an increased probability of fuel cladding damage.

Energy Northwest evaluated worst case conditions for other postulated single partially inserted rod scrams. Energy Northwest determined that if control Rod 30-11 scrammed to the worst case rod position, then the rod would cause the adjacent fuel nodal power to exceed its preconditioning state. The result would be an increased probability of fuel cladding damage for that affected fuel bundle if timely action to reduce core power was not taken (i.e., a reactor scram).

The inspectors reviewed Operations Requalification Training Simulator Guide LR001419, “CRD Mech High Temp, NJ Problem, Single Control Rod Scram,” Revision 3. Step 10 to this simulator guide provides that when Reactor Protection System B scram occurs (Rod 54-37 scrams), the senior reactor operator refers to Procedure ABN-ROD and gives specific direction for power reduction. The associated comments section identifies key steps to Procedure ABN-ROD which include an immediate action to manually scram if the rod scrammed but didn't indicate full in.

Energy Northwest subsequently determined that a more appropriate operator response to a partially scrammed rod is to reduce core flow and therefore reduce core power and to not scram the reactor. Reducing core power by reducing core flow in a prompt manner was determined by Energy Northwest to mitigate the consequences of the event; therefore, minimizing the probability of fuel cladding damage. Energy Northwest subsequently revised Procedure ABN-ROD to reflect the change in operator response. Although in this event no apparent fuel damage resulted, actions to reduce power either through scramming the reactor or, as later analyzed, through core flow reduction as required to prevent fuel cladding damage for a partially scrammed rod. This finding had human performance crosscutting aspects related to the communications between the control room and the operator at the respective hydraulic control unit and for the failure to follow Procedure ABN-ROD and manually scram the reactor.

Analysis. The operating crew’s failure to manually scram the reactor when control Rod 46-19 was inadvertently scrammed and did not fully insert is a performance deficiency. The finding was greater than minor because it affected the fuel cladding barrier. Failing to scram the reactor (rapid power reduction) with a control rod not fully inserted could have resulted in fuel cladding damage if a more limiting control rod had scrammed. This issue was evaluated using NRC Manual Chapter 0609, Significance Determination Process, Phase 1 Worksheet, under the barrier integrity cornerstone Item 2, Fuel Barrier, and was determined to be of very low safety significance. A review of the thermal limits (nodes) for the adjacent fuel assemblies verified that no limits were exceeded.

Enforcement. Technical Specification 5.4.1.a required, in part, that a written procedure shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Appendix A, Section 5, required, in part, that safety related procedures be developed governing abnormal, offnormal, or alarm conditions. Contrary to this requirement, on June 10, 2004, the operating crew failed to follow Step 3.2.1 of Abnormal Condition Procedure ABN-ROD, “Control Rod Fault,” which required in part, that if one or more control rods SCRAM but does not indicate full in, that the reactor be manually scrammed. The operating crew did not scram the reactor as required. This violation is being treated as a noncited violation, consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 50-397/04-05-02, Failure to Manually Scram the Reactor). Energy Northwest documented this issue in their corrective action program as Problem Evaluation Requests 204-0843 and 204-0852.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed four operability evaluations to evaluate Energy Northwest's assessment of operability for degraded or nonconforming equipment performance. The inspectors reviewed the Final Safety Analysis Report , Technical Specifications, applicable system drawings and design specifications, and associated corrective action documents to determine if Energy Northwest had appropriately evaluated operability.

- CR 2-04-05800, DG-GEN-DG1 needs oil added to Engine 1A1; October 18, 2004
- CR 2-04-06260, Air start motors did not initially rotate as expected during preparation for monthly DG3 run; November 10, 2004
- CR 2-04-06588, PRA-EUH-1A Power Supply Disconnect Found Off and Will not remain closed; December 1, 2004
- CR 2-04-06607, Valve RHR-V-4A control inadvertently switched to the alternate shutdown panel; December 2, 2004

b. Findings

Introduction. An Unresolved Item was identified pending the NRC's evaluation of vendor supplied information regarding the acceptability of Energy Northwest's use of Neolube-100 as a thread sealant in the high pressure core spray diesel generator starting air system.

Description. The inspectors reviewed Energy Northwest's operability assessment associated with the high pressure core spray diesel generator's failure to rotate prior to it's monthly surveillance test as documented in Condition Report CR 2-04-06260. The review included a walkdown of the high pressure core spray diesel generator to determine if there were any equipment deficiencies which could have contributed to the failure of the diesel to rotate. During the walkdown, the inspectors noted that diesel air start motor Valve DSA-V-3C1/1 had a minor air leak around the threads of the valve cap. Although the leak was minor and did not impact starting air pressure for the diesel, the inspectors were concerned that degradation of the thread sealant around the threads may have caused the valve to not fully open. If Valve DSA-V-3C1/1 did not fully open, then full starting air pressure may not have been applied to the diesel's air start motors, therefore preventing the diesel from rotating during the pre-startup check. After further discussions with Energy Northwest, it was determined that the applied thread sealant, Neolube-100, was not compatible with the elastomer materials, Viton and Buna-N, which comprise the materials used in the seals and o-rings found in Valve DSA-V-3C1/1. Energy Northwest documented the inspector's concerns in Condition Report CR 2-04-06355. Energy Northwest also requested information from the diesel vendor, Engine Systems Inc., regarding the acceptability of using Neolube-100 in this application. At the end of the inspection period, the requested information from Engine Systems Inc., had not been provided to Energy Northwest. This issue is considered to be an Unresolved Item (URI) (URI 50-397/04-05-03, Thread Sealant Incompatibility with Valve Internals) pending NRC's evaluation of the vendor's recommendations regarding the correct thread sealant to be used on the diesel air start motor valve DSA-V-3C1/1.

Analysis. A determination of the safety significance associated with any performance deficiencies will be addressed in the resolution to the URI.

Enforcement. A determination of the enforcement aspects associated with any performance deficiencies will be addressed in the resolution to the URI.

1R16 Operator Workarounds (71111.16)

a. Inspection Scope

The inspectors reviewed two operator workarounds to evaluate whether the prescribed operator actions could be adequately performed and to evaluate any impact of the workarounds on emergency and abnormal procedures. The inspectors reviewed the facility FSAR, Technical Specifications, and selected emergency and abnormal procedures.

- CR 2-04-05774, Out-of-service annunciator "RHR A HX Outlet Conduct High"; This workaround required that operators request chemistry technicians to sample the A RHR system for conductivity each time the pump was started. High conductivity was indicative of a service water to RHR heat exchanger tube leak, October 16, 2004

- PER [Problem Event Report] 204-0927, Sealing Steam Pressure Control Valve SS-PCV-1A not controlling pressure in band; This workaround directed the operators to manually control sealing steam pressure to the reactor feedwater Pump A because the pressure control valve could not maintain the correct pressure band, November 22, 2004

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17B)

a. Inspection Scope

The procedure requires the review of a minimum of five permanent plant modifications. The inspectors reviewed 11 permanent plant modification packages and associated documentation, such as, safety evaluation review screens and safety evaluations, to verify that they were performed in accordance with plant procedures. The inspectors also reviewed the procedures governing plant modifications to evaluate the effectiveness of the programs for implementing modifications to risk-significant systems, structures, and components, such that these changes did not adversely affect the design and licensing basis of the facility.

The inspectors interviewed the cognizant design and system engineers for the identified modifications as to their understanding of the modification packages. The inspectors evaluated the effectiveness of Energy Northwest's corrective action process to identify and correct problems concerning the performance of permanent plant modifications. In this effort, the inspectors reviewed five corrective action documents and the subsequent corrective actions pertaining to Energy Northwest-identified problems and errors in the performance of permanent plant modifications.

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors observed or completed an in-office review of four postmaintenance tests. The inspectors evaluated the scope of the maintenance activity, reviewed design basis information, and reviewed technical specifications to verify that each test adequately demonstrated equipment operability. The inspection samples included:

- Work Order 01076592; Standby Liquid Control Pump A Maintenance Outage, October 28, 2004
- Work Order 01086766; FDR-V-3 and 4 Disassembly and Inspection, October 28, 2004

- Work Order 01066441; RHR-P-2A Breaker TOC switch replacement, November 1, 2004

- Work Order 01090268; APRM-C Flow Control Trip Circuit Card Replacement, December 6, 2004

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors observed the performance and/or reviewed the results of the six surveillance tests listed below. Of the six surveillance tests, one was an in-service test of a risk significant component and one was a manual evaluation of reactor coolant system unidentified leakage. The inspectors reviewed Technical Specification, Final Safety Analysis Report, and applicable Energy Northwest procedures to determine if the surveillance tests demonstrated that the tested components were capable of performing their intended design functions. Additionally, the inspectors evaluated significant test attributes such as potential preconditioning, clear acceptance criteria, accuracy and range of test equipment, procedure adherence, and completion and acceptability of test data.

- ISP-MS--Q904; RPS Reactor Vessel Steam Dome Pressure - High Div II (B & D) - CFT/CC; Revision 4; October 21, 2004

- OSP-RHR/IST-Q703; RHR Loop B Operability Test; Revision 18; November 17, 2004

- ISP-RCIC-Q901; RCIC Isolation on RCIC Steam Supply Flow High Div 1 - CFT/CC; Revision 12; November 23, 2004

- ICP-RCIC-Q901; RCIC Isolation on RCIC Steam Supply High Div 2 - CFT/CC; Revision 6; November 23, 2004

- PPM 2.11.3; Alternate Determination of Drywell Identified Leakrate; Revision 24; December 1, 2004

- TSP-CONT-C805; Flow Makeup Leak Rate Testing (FDR-V-3 & FDR–V-4)," Revision 1; December 14, 2004

b. Findings

Introduction. A self-revealing Green NCV of Technical Specification 5.4.1.a was identified for a technician's failure to follow a surveillance procedure. Instead of monitoring voltage across two terminals, the technician inadvertently jumpered across the terminals. This resulted in an unexpected isolation signal and the reactor core isolation cooling (RCIC) system being inoperable for approximately two hours.

Description. On November 23, 2004, the RCIC system was rendered inoperable during the performance of an instrumentation and control (I&C) surveillance procedure when the outboard steam supply isolation Valve RCIC-V-63 was inadvertently closed. Surveillance Procedure ICP-RCIC-Q901, "RCIC Isolation on RCIC Steam Supply Flow High Div 2 - CFT/CC," Revision 6, Step 7.1.12, required that the technician monitor two terminals, AA1 and AA2, on RCIC-DPIS-7B, to determine if an associated isolation signal for RCIC-V-63 was present. This was to be accomplished by verifying the presence of 125 VDC with a digital multimeter between Terminals AA1 and AA2. However, the digital multimeter had been incorrectly configured and instead of verifying voltage between Terminals AA1 and AA2, a short between the two terminals was created which input an isolation signal to Valve RCIC-V-63. A post event review determined that the leads from the digital multimeter were not connected to the positive and ground connectors on the meter as would be needed for monitoring voltage. Instead the ground and positive lead jacks had been inadvertently connected together creating a jumper. When the leads were connected to Terminals AA1 and AA2, the isolation signal contact was bypassed by the jumper creating an isolation signal for Valve RCIC-V-63. Control room staff took immediate actions to stabilize RCIC. Procedure ICP-RCIC-Q901 was also exited. The isolation signal was reset and Valve RCIC-V-63 was subsequently opened allowing the operators to return RCIC to an operable status. This finding had human performance crosscutting aspects in that the technician failed to self-check and verify the configuration of the test equipment prior to use.

Analysis. The technician's failure to ensure that the digital multimeter was configured properly to ensure that voltage would be monitored versus inadvertently jumpering across Terminals AA1 and AA2 of RCIC-DPIS-7B was determined to be a performance deficiency. This finding was more than minor because it was a human performance 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. The safety significance associated with this performance deficiency was evaluated using the NRC Manual Chapter 0609, Significance Determination Process, Phase 1 Worksheet, under the mitigating system cornerstone. The finding was determined to be of very low safety significance 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 (Green).

Enforcement. Technical Specification 5.4.1.a required, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operation)," Appendix A, Section 8.b, required, in part, that specific procedures for surveillance tests should be written to include RCIC tests. Contrary to this requirement on November 23, 2004, an I&C technician failed to follow Step 7.1.12 of Surveillance Procedure ICP-RCIC-Q901 and inadvertently rendered RCIC inoperable. The technician was to monitor voltage across two terminals to ensure that an isolation signal for Valve RCIC-V-63 was not present. However, the technician failed to verify the configuration of a digital multimeter prior to use when checking the terminal voltage and inadvertently jumpered the two terminals together initiating an isolation signal for RCIC. This violation is being treated as a noncited violation, consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 50-397/04-05-04, Failure to Verify Test Equipment Configuration). Energy Northwest documented this issue in their corrective action program in PER 204-1200. Immediate corrective actions included a maintenance department stand down to explain the event to electrical and I&C craft and supervisors.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors evaluated the two temporary modifications listed below to determine the adequacy of the associated 10 CFR 50.59 screenings and reviewed the Final Safety Analysis Report to verify that the temporary modifications were consistent with these documents and requirements. The inspectors also verified that the temporary modifications complied with the requirements of Administrative Procedure 1.3.9, "Temporary Modifications," Revision 38. The inspectors also walked down accessible portions of the systems and verified control room procedures had been updated to reflect any changes where applicable.

- Temporary Modification TMR 04-003; Gagging Open Reactor Feedwater Pump 1B Suction Valve

- Temporary Modification TMR 04-002; Disconnect Heater Power at Rear of PRM-TIC-1A, PRM-TIC-1B and PRM-TIC-1C; April 26, 2004

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Mitigating Systems Cornerstone

a. Inspection Scope

The inspectors assessed the accuracy of the performance indicators listed below. The inspectors compared the data with operator logs, equipment out of service logs and corrective action documents for the last four quarters. The inspectors verified that Energy Northwest calculated performance indicators in accordance with NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 2.

- Safety System Unavailability - BWR Heat Removal System (Reactor Core Isolation System)
- Safety System Unavailability - Emergency AC Power

b. Findings

No findings of significance were identified.

4OA2 Problem Identification and Resolution

.1 Annual Sample Review

a. Inspection Scope

During a tour of the control room on September 24, 2004, the inspectors noted that Area Radiation Monitor (ARM)-RIS-32 was out of service. ARM-RIS-32 monitored radiation levels in the Reactor Building 471' elevation and was one of several area radiation monitors located throughout the plant which were utilized for emergency operating procedure entry conditions and for emergency classification purposes. The inspectors questioned the control room staff what compensatory measures had been implemented to address the out of service ARM. The control room staff could not identify nor were they aware of any compensatory measures. The inspectors were concerned that without appropriate compensatory measures in place, the reactor operators may not readily recognize if radiation levels were high enough to warrant an emergency classification or an entry into an emergency procedure. The inspectors reviewed Energy Northwest's assessment and corrective actions associated with the issue.

b. Findings and Observations

The following observations were noted during a review of corrective actions associated with the out-of-service radiation monitor ARM-RIS-32.

On February 3, 2004, ARM-RIS-32 was determined to be inoperable after failing its calibration. Energy Northwest documented the failure in PER 204-0434. However, operations staff did not identify in PER 204-0434 that the instrument was used for emergency operating plan (EOP) entries and for emergency classification criteria. The only action taken was to write a work request to repair the instrument. PER 204-0434 was subsequently closed on February 4, 2004.

On July 27, 2004, Energy Northwest documented in CR 2-04-03945 that an evaluation should be performed to determine the acceptability of replacing ARM-RIS-32 detector with a detector from a different ARM to expedite the repair. Operations staff did not identify in CR 2-04-03945 that the instrument was used for EOP entries and for emergency classification criteria.

The inspectors noted that PER 204-0434 and CR 2-04-039435 represented two missed opportunities by Energy Northwest to establish appropriate compensatory measures for ARM-RIS-32. Energy Northwest documented the inspectors concerns in CR 2-04-05365. Energy Northwest subsequently determined that another area radiation monitor ARM-RIS-24, also located on the Reactor Building 471' elevation was identified for the same EOP entry conditions and emergency classification criteria as ARM-RIS-32 and would have provided similar indications to ensure that the appropriate EOP's were entered and that the appropriate emergency classifications were determined.

.2 Semi-Annual Trend Review

a. Inspection Scope

The inspectors reviewed Energy Northwest's corrective action program (CAP) and associated documents to identify equipment trends that could indicate the existence of a more significant safety issue. The inspector's review included the six month period of July through December 2004, although some examples expanded beyond those dates when the scope of the trend warranted. The inspectors reviewed the repetitive and/or rework maintenance lists, system health reports, quality assurance audit/surveillance reports and maintenance rule assessments. The inspectors reviewed selected corrective actions associated with any Energy Northwest identified trends to ensure that corrective actions were appropriately identified and documented.

b. Findings and Observations

No findings of significance were identified. The inspectors evaluated trending methodology and observed that Energy Northwest had performed a detailed review. Energy Northwest routinely reviewed cause codes and key words to identify potential trends in their CAP data base. The inspectors compared Energy Northwest's identified trends with the results of the inspectors' evaluation and did not identify any discrepancies or potential trends that Energy Northwest had failed to identify. However, the inspectors noted that Energy Northwest had documented a trend associated with a station wide lack of regard for, or awareness of, Foreign Material Exclusion (FME) controls in the Circulating Water System (CWS) and a tolerance for accepting unplanned relief valve lifts, as discussed below. The inspectors noted that Energy Northwest documented five corrective action documents associated with relief valve failures and six corrective action documents related to breeches of FME in the CWS which led to the two identified trends.

Circulating Water System Foreign Material Exclusion

Energy Northwest documented in Problem Event Report (PER) 204-0811 a station wide lack of regard for, or awareness of, FME controls in the CWS indicating a lack of commitment to implementation of the FME program, ineffective corrective actions for previously identified foreign material problems, and a lack of appropriate foreign material controls in the CWS. Foreign material exclusion control of the CWS is important because the facility had experienced previous forced downpowers to inspect and repair main condenser tubes which had been damaged due to foreign material in the CWS. A corrective action plan was implemented in PER Resolution 204-0811 to prevent reoccurrence of this problem. This plan included establishing a focus team to evaluate the need for physical barriers to provide effective protection against foreign material sources, implementing a strict program and administrative controls for FME for the CWS and main condenser water boxes, providing clear signage that communicates a strong message supporting FME controls at all locations that present openings to the CWS and main condenser water boxes, communicating the consequences and significance of main condenser tube leaks (caused by erosion from foreign material in the CWS) which could lead to an extended reduction in reactor power to plug leaking condenser tubes, and assessing the effectiveness of corrective actions to prevent reoccurrence during a CWS or refueling outage. Energy Northwest documented in CR 2-04-05267 that PER Resolution 204-0811 did not contain interim actions for FME program controls for work around the CWS basin. After interim actions were added, the inspectors noted that Energy Northwest identified an additional issue associated with CWS FME control deficiencies as documented in CR 2-04-06344. This CR documented that following a maintenance activity that foreign material such as bolts, washers, nails, etc., had been left laying around CW-FN-10. The cooling towers had been posted as an FME exclusion area. Although no FME was assumed to have entered the CWS, this CR noted a continued lack of sensitivity to FME controls around the CWS.

Unplanned Relief Valve Lifts and Failures to Reseat

Energy Northwest documented in PER 204-1047 a problem identifying that the station had accepted relief valve failures without an appropriate level of concern or had acquired a high tolerance for such occurrences. The inspectors reviewed three corrective action documents associated with relief valve failures which included; 1) CR 2-04-04549, which documented that relief valve COND-RV-177A had required replacement twice during Forced Outage 04-01 due to lifting and not reseating, 2) CR 2-04-04078, which documented that condensate heat exchanger COND-HX-1C tube side relief was lifting every 30 seconds to 1 minute with one condensate booster pump running, and 3) CR 2-04-06053, which documented inadvertent lifting and failure of reactor water cleanup (RWCU) relief Valve RWCU-RV-3 to reseat. Relief valve failures can be significant in that excessive leakage beyond the capacity to process wastewater can require on-line repairs or challenge the operability of safety related equipment. Additionally, a relief valve that lifts and fails to properly reseat can contribute to increased radiological concerns due to high airborne radioactivity concerns or can contribute to a spread of surface contamination. **A corrective action plan was implemented (November 18, 2004) in accordance with PER Resolution 204-1047 to prevent reoccurrence of this problem. This plan provided guidance to System Engineering, Maintenance Component Engineers and Center Review Group that system related evaluations of relief valve lifting or persistent relief valve issues should be led by the System Engineer or for emergent problems by the Engineering Fix It Now team. Those problems related solely to maintenance such as minor leakage, test stand problems, rework, etc., should be dispositioned by maintenance.**

.3 Cross-References to Problem Identification and Resolution Findings Documented Elsewhere

A problem identification and resolution crosscutting aspect was identified when Energy Northwest failed to document in their corrective action program in a timely manner procedural inadequacies associated with Abnormal Condition Procedure ABN-ASH. Approximately six weeks elapsed between when the inadequacies were first identified and the problem being documented for resolution. Energy Northwest took appropriate corrective actions in the interim (Section 1R01).

4OA3 Event Followup (71153)

.1 (Closed) Licensee Event Report (LER) 05000397/2003-12: Unanticipated Inoperability of Both Trains of Control Room Emergency Filtration System

On November 4, 2003, Energy Northwest determined that a condition that could have prevented the fulfilment of a safety function needed to mitigate the consequences of an accident had existed for 4 hours on November 1, 2003. Specifically, the normal and both remote outside air intakes for the control room emergency filtration system were manually isolated during testing to measure control room in-leakage. In this configuration, the system could not pressurize the control room with filtered air as described in the accident analysis. This was determined to be a violation of Technical

Specification 3.7.3 (see Section 4OA7.1 for details). The issue has been entered into Energy Northwest's corrective action program as Problem Evaluation Report 203-3975.

.2 (Closed) LER 05000397/2004-04: Reactor Scram Due to Failure of a Ceramic Capacitor on a NUCANA Servo Driver (NSD) Circuit Board

On July 30, 2004, the reactor automatically scrammed due to a high reactor pressure vessel trip when a turbine governor valve drifted closed. The valve drifted closed due to failure of a bypass capacitor on a circuit board associated with the governor valve electro-hydraulic control system. This event was discussed in IR 05000397/2004-04 and an associated violation of NRC requirements was documented (see IR 2004-04, Section 4OA3.1). Additionally, URI 50-397/04-04-03 was opened pending the NRC review of performance issues associated with the operators response to the reactor scram and the declaration of an alert (See IR 2004-04, Section 4OA3.1).
Section 4OA5.1 of this report documents the resolution of URI 50-397/04-04-03 and an associated violation of NRC requirements. A minor violation of 10 CFR 50.73 (a) (1) was identified for the failure to issue the licensee event report within 60 days (actual 66 days) after discovery of the event.

4OA4 Crosscutting Aspects of Findings

A human performance crosscutting aspect was identified for the inadequate procedure which could not be readily implemented as written (Section 1R01).

Human performance crosscutting aspects were identified related to the communications between the control room and the operator at the respective hydraulic control unit and when the control room staff failed to scram the reactor in accordance with plant procedures after a control rod was inadvertently scrammed (Section 1R14).

A human performance crosscutting aspect was identified when a technician failed to verify the configuration of a multi-meter and inadvertently caused an automatic isolation of RCIC. This resulted in RCIC being inoperable for approximately two hours (Section 1R22).

Human performance crosscutting aspects were identified for this finding involving the operator response to the annunciators and communications within the control that failed to identify the cause for reactor trip that was considered in an input to an Alert declaration (Section 4OA5.1).

4OA5 OTHER

.1 (Closed) URI 50-397/04-04-03

a. Inspection Scope

Inspection Report 50-397/04-04, Section 4OA3.1, documented several issues related to an automatic reactor scram and an associated alert declaration which had occurred on

July 30, 2004. Unresolved Item 50-397/04-04-03 was opened pending the NRC's final review and assessment of the safety significance and enforcement actions associated with the event, the alert declaration, and other identified performance deficiencies. This section addresses EA 04-192.

b. Findings

Operator Acknowledgment and Clearing of Key Plant Annunciators

Introduction. A self-revealing Green NCV of Technical Specification 5.4.1.a was identified for the failure of a reactor operator to communicate to the Control Room Supervisor (CRS) a key alarming annunciator following a reactor scram on July 30, 2004, as required by Procedure PPM 1.3.1, "Operating Policies, Programs and Practices," Revision 66. This contributed to a delay in validating and determining the cause of the reactor scram.

Description. Immediately following the reactor scram on July 30, 2004, the reactor operator acknowledged and inadvertently reset Alarm Panel A-7 and A-8. This resulted in several key annunciators, which were alarming to clear, including Annunciator "RPV Pressure High Trip" which indicated the cause of the reactor scram.
Procedure PPM 1.3.1, "Operating Policies, Programs and Practices," Revision 66, Section 4.11.5.a, Volume 4, Local and Remote Annunciator Response Procedures (ARPs), provides that the control room supervisor should be informed of all nonnuissance alarms in the control room as they occur. Contrary to this requirement, the reactor operator failed to note which annunciators were alarming prior to resetting the alarm panel and therefore did not inform the CRS that Annunciator "RPV Pressure High Trip" had been in an alarmed condition. Operating Instruction Procedure OI-9, "Operations Expectations and Standards," Revision Z, Section 13.0, Annunciator Response, provides direction that during transient/EOP implementation, alarms are promptly evaluated and operationally significant alarms are communicated by the operator to the CRS and that annunciators flagged as potential emergency operating procedure (EOP) entries are assessed by the operator and communicated to the CRS as EOP entry conditions including parameter, value, units, and trend. Following the alarm panel having been reset, the cause for the reactor trip, high reactor pressure as indicated on Annunciator "RPV Pressure High Trip", was not communicated to the CRS and the cause for the trip was not ascertained until approximately 20 minutes later when the alarm logs were reviewed. The valid reactor trip determination was later used in a determination to declare an Alert

The operator's failure to properly implement Procedure PPM 1.3.1 and inform the control room supervisor that annunciator "RPV Pressure High Trip" had alarmed was considered to be a performance deficiency. Additionally, the failure to communicate the RPV High Pressure Trip annunciator to the control room supervisor contributed to a delay in the validation and determination of the cause of the reactor trip. Human performance crosscutting aspects were identified for this finding involving the operator response to the annunciators and the lack of command and control within the control room that failed to promptly determine the cause for reactor trip that was later considered in the emergency response managers decision to declare an Alert.

Analysis. This finding was greater than minor because the failure to properly acknowledge and address the RPV [reactor pressure vessel] annunciators was a human performance error (post event) 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. By acknowledging and resetting key annunciators prior to communicating key parameters, values and trends may not be appropriately considered for significance of mitigating system response, emergency operating procedure entry conditions as well as emergency plan implementation. The finding was determined to be of very low risk significance (Green) because the finding did not involve a design or qualification deficiency, it did not represent a loss of safety function of a system or train, and was not risk significant because of seismic, fire or flooding event. Other factors which mitigated the safety significance of the finding included the availability of other plant information to the control room staff (i.e. alarm printer, chart recorders), which when reviewed approximately 30 minutes after the reactor scram, validated and identified the cause of the scram. Additionally, the operators entered EOP 5.1.1, "RPV Control," on low RPV level following the scram which was the EOP referenced by the annunciator response procedure for high reactor pressure trip.

Enforcement. Technical Specification 5.4.1.a required, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operation)," Appendix A, Section 1, established that administrative procedures including procedures that provide for the authorities and responsibilities for safe operation of the plant be written and adhered to Procedure 1.3.1, "Operating Policies, Programs and Practices," Section 4.11.5, "Volume 4 Local and Remote Annunciator Response Procedures (ARPs)," provides in Step 4.11.5.a that the control room supervisor be informed of all nonnuisance alarms in the control room as they occur. Contrary to Technical Specification 5.4.1.a, the reactor operators failed to inform the control room supervisor that annunciator "RPV Pressure High Trip," had alarmed. Not communicating this annunciator to the CRS delayed the determination of the cause and validity of the reactor trip. This violation is being treated as a NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 50-397/04-05-05, Failure to Communicate Key Annunciators Associated with EOP Entries).

Transitory Event Notification Process

Description. On July 30, 2004, the inspectors observed and evaluated Energy Northwest's response to an automatic reactor scram and Alert declaration which was made at 10:00 p.m. PDT. At the time of the Alert declaration was made the conditions for declaring the Alert no longer existed since all control rods indicated full in. Energy Northwest later determined that all rods fully inserted on the initial scram signal and therefore an actual emergency never existed.

Emergency Plan Implementing Procedure 13.1.1, Step 3.7, "Transitory Event Classification," provided that a transitory event classification be made whenever it is discovered that a condition had existed which met the emergency classification criteria, but where no emergency had been declared and the basis for which no longer exists. Contrary to this procedure, the shift manager failed to implement the transitory event notification process and instead declared an Alert when plant conditions did not warrant such a declaration. The NRC evaluated the failure to implement EPIP 13.1.1 and determined that no violation of regulatory requirements existed since Energy Northwest's Emergency Plan, which specifies the requirements which Energy Northwest must meet regarding emergency planning, did not provide directions or requirements associated with transitory event notification. Additionally, the NRC determined that the declaration of the Alert did not prevent off-site local and state emergency centers from taking actions to protect the health and safety of the public.

Analysis. The issue involving a transitory declaration was reviewed using NRC Manual Chapter 0609, Significance Determination Process [SDP], Appendix B, "Emergency Preparedness Significance Determination Process," and determined that no emergency plan planning standard functions were adversely affected by the failure to implement a transitory event notification. The issue did not result in a violation of a regulatory requirement and was not assessed for safety significance.

Enforcement. No violations of NRC requirements were identified. However, Energy Northwest did take corrective actions to retrain operations staff on the usage and applicability of the transitory event notification process as prescribed in Emergency Plan Implementing Procedure 13.1.1.

4OA6 Meetings, Including Exit

Resident Inspector Routine Exit Summary

On November 18, 2004, the inspectors presented the results of the biannual permanent plant modification to Mr. D. Atkinson, and other members of Energy Northwest management. Energy Northwest management acknowledged the inspection findings.

On January 6, 2005, the resident inspectors presented the inspection results to Mr. V. Parrish, Chief Executive Officer, and other members of his staff who acknowledged the findings presented.

The inspectors asked Energy Northwest whether any materials examined during the inspection should be considered proprietary. It was determined that no proprietary information had been presented to the inspectors.

4OA7 Energy Northwest Identified Violations

The following violations of very low risk significance (Green) were identified by Energy Northwest and are violations of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as noncited violations.

Cornerstone: Barrier Integrity

.1 Licensee Event Report 05000397/2003-12 reported the unanticipated inoperability of both trains of control room emergency filtration system. This is a violation of Technical Specification 3.7.3.E. Technical Specification 3.7.3.E requires, in part, that with two control room emergency filtration subsystems inoperable that the plant immediately enter Technical Specification 3.0.3. This was identified in Energy Northwest's corrective action system as Problem Evaluation Report PER 203-3975. This issue was evaluated using NRC Manual Chapter 0609, Significance Determination Process, Phase 1 worksheet under the barrier cornerstone. Since the issue was a degradation of the barrier function of the control room against smoke or a toxic gas atmosphere, a Phase 3 evaluation was required. The Phase 3 evaluation determined that the 4 hour time duration was insufficient to result in a finding greater than very low safety significance.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Energy Northwest

D. Atkinson, Vice President, Technical Services
J. Bekhazi, Maintenance Manager
I. Borland, Manager, Radiation Protection
B. Boyum, Assistant Engineering Manager, Engineering
G. Cullen, Assistant to the Plant General Manager
D. Coleman, Manager, Performance Assessment and Regulatory Programs
D. Feldman, System Engineering Manager
B. Gardes, Performance Manager
P. Harness, Project Manager, Engineering
T. Hoyle, Component Programs Supervisor
M. Humphries, Manager, Engineering
W. LaFramboise, Manager, Technical Engineering
T. Lynch, Plant General Manager
C. Moore, Supervisor, Emergency Preparedness
S. Oxenford, Vice President Nuclear Generation
V. Parrish, Chief Executive Officer
S. Scammon, Manager, Resource Protection
C. Sly, Senior Engineer, Licensing
R. Webring, Vice President, Nuclear Generation

NRC Personnel

R. Cohen, Resident Inspector
Z. Dunham, Senior Resident Inspector

ITEMS OPENED AND CLOSED

Items Opened, Closed, and Discussed During this Inspection

Opened

50-397/04-05-03	URI	Thread Sealant Incompatibility with Valve Internals (Section 1R15)

Opened and Closed

50-397/04-05-01	NCV	Inadequate Ash Fall Procedure (Section 1R01)
50-397/04-05-02	NCV	Failure to Manually Scram the Reactor (Section 1R14)
50-397/04-05-04	NCV	Failure to Verify Test Equipment Configuration (Section 1R22)

50-397/04-05-05	NCV	Failure to Communicate Key Annunciators Associated with EOP Entries (Section 4OA5.1)

Closed

50-397/04-04-03	URI	NRC Review of Performance Issues Associated with the July 30, 2004, Reactor Scram and the Declaration of Alert (Section 4OA5.1)
50-397/2003012	LER	Unanticipated Inoperability of Both Trains of Control Room Emergency Filtration System (Section 4OA3.1)
50-397/200404	LER	Reactor Scram Due to Failure of a Ceramic Capacitor on a NUCANA Servo Driver (NSD) Circuit Board (Section 4OA3.2)

Discussed

None

PARTIAL LIST OF DOCUMENTS REVIEWED

Procedures

PPM 1.5.11; Maintenance Rule Program; Revision 6

TI 4.22; Maintenance Rule Program; Revision 8

OSP-SW-Q101; SW Spray Pond Average Sediment Depth Measurement; Revision 2

ABN-ASH; Ash Fall; Revision 5

PPM 4.DG1; DG1 Annunciator Panel Alarms; Revision 9

PPM 1.3.1; Operating Policies, Programs and Practices; Revision 66

PPM 4.601.A4; 601.A4 Annunciator Panel Alarms; Revision 22

PPM 12.2.2; Sampling System Components Locations and Valve Lineup; Revision 17

TSP-CONT-C805; Flow Makeup Leak Rate Testing (FDR-V-3 & FDR-V-4); Revision 0

WNP-2 Inservice Testing Program Plan (Pumps and Valves) 2nd Interval; Revision 2

Primary Containment Leakage Rate Testing Program Plan; Revision 2

ISP-APRM-Q401; APRM Channels A, C, E Modes 1 and 2 - CFT; Revision 10

PPM 2.11.3; Equipment Drain System; Revision 24

OSP-RHR/IST-Q703; RHR Loop B Operability Test; Revision 18

ISP-RCIC-Q901; RCIC Isolation on RCIC Steam Supply Flow High Div 1 - CFT/CC

SOP-DG-1-START, Emergency Diesel Generator (Div 1)

SOP-DG-2-START, Emergency Diesel Generator (Div 2)

SOP-DG-3-START; High Pressure Core Spray Emergency Generator

SOP-RHR-STBY; Flow Diagram Residual Heat Removal Loop C

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

SOP-HPCS-STBY; Placing HPCS in Standby Status

ISP-MS-QSP-Q904; RPS REACTOR VESSEL STEAM DOME PRESSURE - HIGH DIV II (B & D) - CFT/CC

DES-2-1, Plant Design Changes, Revision 11

DES-2-2, Field Change Requests, Revision 3

EDP 2.11, Field Changes, Revision 6

EI 2.8, Generating Facility Design Change Process, Revision 17

ENG-DES-02, Columbia Generating Station Design Change Process, Revision 10

PPM 1.4.1, Plant Modifications, Revision 28

SWP-CAP-01, Corrective Action Program, Revision 8

SWP-CAP-02, Cause Determination, Revision 2

SWP-CAP-03, Operating Experience Program, Revision 3

SWP-CAP-05, Corrective Action Review Board (CARB), Revision 2

SWP-DES-01, Plant Modifications & Configuration Control, Revision 5

TSP-CONT-B802, Low Pressure Hydraulic Testing of Containment Isolation Valves, Revision 1

Calculations

NE-02-90-08; Sump Pump Out Timer Setpoint Calculation; Revision 0

ME-02-87-95; Div 1 and 2 Diesel Generator Combustion air filter loading times during a volcanic event

ME-02-91-51; Diesel Generator Engine Lube Oil Sump Capacity; Revision 0

Drawings

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

M512; Sheet 1, Flow Diagram Diesel Oil and Miscellaneous Systems Diesel Generator Building

M529, Nuclear Boiler and Main Steam System, J12, J13, J5

PERs / Condition Reports

PER 201-1259	PER 202-2911	CR 2-04-00016	PER 202-2954
PER 202-3392	CR 2-04-02164	PER 202-3458	PER 202-3471
CR 2-04-06078	PER 203-0001	PER 203-0002	CR 2-04-06208
PER 203-3953	PER 203-4002	PER 204-0018	PER 204-0339
PER 204-0589	CR 2-04-06294	CR 2-04-06588	CR 2-04-06607
CR 2-04-06260	CR 2-04-06355	PER 204-0791	CR 2-04-02395
CR 2-04-05774	CR 2-04-06078	CR 2-04-06567	CR 2-04-05879
CR 2-04-06534	CR 2-04-05365	CR 2-04-03945	PER 204-0434
CR 2-04-05868	CR 2-04-05800	PER 204-0927	PER 204-1200
PER 203-2149	PER 203-2309	PER 204-1047	PER 297-0547
CR 2-04-04316	CR 2-04-04432	CR 2-04-06373	PER 298-0281
PER 202-3389	CR 2-04-04395	CR 2-04-04576	CR 2-04-05267
CR 2-04-05269	CR 2-04-06344	CR 2-04-06462	PER 204-0811
CR 2-04-04078	CR 2-04-04549	CR 2-04-04642	CR 2-04-06053
CR 2-04-06687	CR 2-04-06750	PER 204-1044	PER 204-1047

Miscellaneous

LR 001607; Revision 0

WO 01066441

WO 01086766

WO 01037254

TM-2084; Basis for Diesel Engine Lube Oil Availability Requirement and Lube Oil Consumption Rate; Revision 0

Clearance Order C-ANN-P601/A4-001; October 17, 2004

FAO 202-3471; FDR-V-3 and 4 are inoperable because of an adverse trend in valve stroke time and LLRT results; April 16, 2003

WO 01090268

CMR 94-1140

TMR 04-002; Disconnect Heater Power at Rear of PRM-TIC-1A, PRM-TIC-1B and PRM-TIC-1C; April 26, 2004

CCER No. C94-0017

Night Order 612; October 1, 2004

AU-CA-04; Corrective Action Program Audit, Audit Exit; November 4, 2004

SR-4-07; Continuous Monitoring Summary Report; September 3, 2004

Calculation Modification Requests

0000001547

0000002245

Design Changes:

NUMBER	DESCRIPTION	REVISION
BDC 99-0107	Install Vent/Equalizing Line to Eliminate the Potential of Pressure Locking of Valve RCIC-V-31	0A
Calc E/I-02-02-03	Maximum Setpoint Determination for Instrument Loop TSW- RIS-5	0
Calc E/I-02-87-03	Incorporate Nameplate Data for COND-P-4 and -5 per PERA 299-1255-02	4
Calc E/I-02-91-03	Division 1 & 2 & 3 Diesel Generator Loading	10
Calc 2.12.58	Second Level Undervoltage Relay Settings for SM-4, 7 & 8	5
Calc 8.14.96C	Evaluate Motor Weight Changes for Valves RCIC-V-22 and RCIC-V-59	0

Design Changes:

NUMBER	DESCRIPTION	REVISION
DCP 86-0324-0A	Standby Service Water Keep Fill Subsystem Installation	0A
PMR 96-0198-0	Deactivation of Standby Service Water Keep Fill Subsystem	0A
PMR 99-0051-0	Remove Push-Buttons and Lights for Check Valves RHR-V-41B,C, RHR-V-50B, and RHR-V-89	0A
TER 00136701	Remove Vent/Drain Test Valve HPCS-V-102 due to Susceptibility to Fatigue Failure	0
TER 00136801	Remove Vent/Drain Test Valve LPCS-V-83 due to Susceptibility to Fatigue Failure	0

Miscellaneous Documents:

NUMBER	TITLE/SUBJECT	REVISION
CCER C91-0223	Component Classification Equipment Record	2
	Final Safety Analysis Report	Amendment 58
	Inservice Testing Program Plan, “Second 10-Year Interval”	2