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

July 3, 2006

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 05000397/2006011

Dear Mr. Parrish:

On June 1, 2006, 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 with Mr. D. Atkinson and other members of your staff on June 1, 2006.

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 baseline inspection was conducted to evaluate the circumstances and the adequacy of your short term and long term corrective actions related to the failure of service water Pump 1A and degradation of service water Pump 1B.

This report documents one self-revealing finding which was determined to 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. Because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these findings as noncited violations (NCVs) 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 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/

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

Docket: 50-397
License: NPF-21

Enclosure:
NRC Inspection Report
05000397/2006011

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	50-397
License:	NPF-21
Report:	05000397/2006011
Licensee:	Energy Northwest
Facility:	Columbia Generating Station
Location:	Richland, Washington
Dates:	April 10 through June 1, 2006
Inspectors:	Z. Dunham, Senior Resident Inspector, Project Branch A, DRP S. Unikewicz, Senior Mechanical Engineer, NRR/Division of Component Integrity D. Proulx, Senior Engineering Inspector, Engineering Branch 2, DRS B. Henderson, Engineering Inspector, Engineering Branch 1, DRS S. Garchow, Operations Engineer, Operations Branch, DRS T. Brown, Project Engineer, Project Branch A, DRP
Accompanying Person:	J. McHale, Mechanical Engineer, NRR/Division of Component Integrity
Approved By:	C. E. Johnson, Chief, Project Branch A, Division of Reactor Projects
ATTACHMENT:	Supplemental Information

CONTENTS

SUMMARY OF FINDINGS

IR05000397/2006011; 4/10/2006 - 6/1/2006; Columbia Generating Station; Identification and Resolution of Problems.

The report covered an eight week period of inspection by a senior resident inspector, regional and NRR engineering inspectors. One green noncited violation was 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: Mitigating Systems

- Green. A self-revealing noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions," was identified for failure to promptly identify conditions adverse to quality associated with the safety-related standby service water pumps. Specifically, Energy Northwest failed to implement actions identified in 1994 in response to external operating experience (Information Notice 93-68) associated with the standby service water pumps. The failure to implement the actions resulted in the failure to promptly identify that shaft couplings on standby service water Pump 1A shaft had failed due to intergranular stress corrosion cracking prior to the failure revealing itself on June 14, 2005. Energy Northwest later determined during an inspection in December 2005, that a coupling on standby service water Pump 1B shaft had also failed, although the pump continued to demonstrate acceptable performance. Energy Northwest replaced both standby service water pumps and implemented corrective actions to ensure periodic future inspections of service water Pumps 1A and 1B to ensure their operational readiness.

  This finding is greater than minor because it was an equipment reliability issue which impacted the mitigating systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Although the finding affected the mitigating systems cornerstone objectives, the finding was of very low safety significance because the finding did not result in a loss of function of standby service water Pump 1A, did not result in a loss of safety function of the system, did not represent a loss of safety function of non-technical specification equipment, and did not screen as potentially risk significant due to external events. The cause of the finding was related to the crosscutting element of problem identification and resolution because of Energy Northwest's failure to implement identified actions to inspect either standby service water pump in response to Information Notice 93-68. (Section 4OA2.2)

B. Licensee Identified Violations

One violation of very low significance was identified by the licensee and reviewed by the inspectors. Corrective actions taken or planned by the licensee appeared reasonable. This violation is listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status:

Columbia Generating Station operated at 100 percent power during the inspection period with the exception of brief periodic down powers to support regional power demands.

Summary of Service Water Pumps 1A and 1B (SW-P-1A and SW-P-1B) Shaft Failures and Response by Energy Northwest

On June 14, 2005, Energy Northwest declared SW-P-1A inoperable after identifying that pump performance had declined as noted by abnormally low pump discharge pressure and flow. This was identified after control room operators noted that service water flow through the associated residual heat removal exchanger was below that required to meet administrative flow requirements following a start of SW-P-1A to support testing on residual heat removal Train A. Subsequently, during a review of plant computer data, operators identified that SW-P-1A had been degrading as early as May 18 as evidenced by marked decreases in pump performance since that time. On June 15, operations conducted surveillance test OSP-SW/IST-Q701 and determined that SW-P-1A pressure and flow had degraded to the action range of the pump performance curve. Later on June 15, Columbia Generating Station automatically scrammed as a result of an unrelated failure of the main turbine control system and entered forced outage FO 05-01. On June 18, Energy Northwest determined during an inspection of SW-P-1A that the degraded performance of SW-P-1A was a result of a failure of the pump shaft and wear of the pump impeller and bowl. Failure of two shaft segment ends and couplings occurred as a result of intergranular stress corrosion cracking (IGSCC) as a result of improper tempering of the shaft material during manufacture (See Inspection Report 0500397/2005003, Section 1R12, for more details associated with the shaft failure of SW-P-1A). Energy Northwest replaced SW-P-1A with an available spare pump, completed required post-installation testing of SW-P-1A, and declared SW-P-1A operable on June 21.

Following the identification of the failed shaft on SW-P-1A, Energy Northwest determined that SW-P-1B was also susceptible to the same failure mechanism as SW-P-1A due to: (1) inadequately tempered shaft material during manufacture similar to SW-P-1A; (2) identical operating environment as SW-P-1A which is conducive to IGSCC; (3) similar operating history and run time as SW-P-1A; and (4) lack of inspection of SW-P-1B since initial installation. Energy Northwest concluded that SW-P-1B was operable and fully qualified based on prior successful surveillance test results and no noted abnormal trends in pump performance. Although there were no noted performance problems with SW-P-1B, Energy Northwest concluded that the pump should be inspected at the first opportunity given the extent of condition concerns noted above. However, an inspection of SW-P-1B could not be immediately accommodated because disassembly of the pump required destruction of pump shaft coupling sleeves to examine the pump shaft segment ends, the components of concern. Spare coupling sleeves to facilitate reassembly of SW-P-1B were not available on site and could not be readily procured. Energy Northwest subsequently decided to startup the plant and to expedite procurement of spare pump shaft components to allow an inspection of SW-P-1B at the earliest opportunity. Plant restart occurred on June 22, 2005.

Although spare pump parts were procured and were available in November 2005 to support an inspection of SW-P-1B, Energy Northwest delayed inspection of the pump because: (1) in parallel with procuring spare shaft coupling components, procurement of an entire spare pump had been expedited and was scheduled for delivery in December 2005. A replacement of the entire pump instead of disassembly and inspection would minimize the overall unavailability time of SW-P-1B and minimize the overall impact on core damage frequency; and (2) Energy Northwest submitted a one-time technical specification amendment request to the NRC to extend Technical Specifications 3.7.1.B and 3.8.1.B from 72 hours to 144 hours to allow sufficient time to disassemble or replace SW-P-1B at power which had not yet been approved. On December 11, 2005, Energy Northwest operated SW-P-1B for 24 hours to verify the capability of the pump to run for at least 24 hours post-accident conditions. SW-P-1B was subsequently replaced on December 12 through 15, 2005. Similar to SW-P-1A, a subsequent inspection of the as-found condition of SW-P-1B determined that one pump shaft segment had failed due to IGSCC and that impeller and pump bowl casing wear had occurred.

Description of Safety Function of SW-P-1A and SW-P-1B and Other Relevant Background Information

The standby service water system and ultimate heat sink function is to supply cooling water to remove heat from all nuclear plant equipment that are essential for safe and orderly shutdown of the reactor, to maintain it in a safe condition, and to remove decay heat from the reactor during shutdown conditions. During all normal operating conditions, including normal shutdown as well as emergency conditions, waste heat from the reactor auxiliary systems is transferred to the ultimate heat sink via the standby service water system.

SW-P-1A and SW-P-1B were manufactured by Byron Jackson, Model 28KXH3, and are required by design to provide at a minimum 10,500 gpm rated flow at 500 ft of discharge head. Both pumps were installed in 1979, and prior to the failure of SW-P-1A, had not been replaced, refurbished, removed, nor the pump internals inspected since initial installation. Both pumps are exposed to the same environment and physical conditions.

The standby service water pump design consists of five sections of shaft with four sets of shaft coupling components. Each set of shaft coupling components consists of a drive key and a clamp ring that are held by a sleeve which is located by two gib keys. At the point where two shaft sections join, the split clamp ring is installed over mating shaft shoulders. The shaft shoulder was the failed component which allowed the pump shaft to drop and allow the pump impeller to rest on the casing bowl resulting in milling and wear of the impeller into the bowl during operation.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R15 Operability Evaluations (71111.15)

.1 SW-P-1A and SW-P-1B Shaft Degradation

a. Inspection Scope

The inspectors assessed Energy Northwest's evaluation of the ability of SW-P-1A and SW-P-1B to start and run successfully for 24 hours, consistent with probabilistic risk assessment (PRA) modeling, and for a 30 day design mission time (consistent with design requirements of the ultimate heat sink). The inspectors reviewed the licensee's basis for the 24 hour PRA and 30 day design basis mission times, as well as the licensee and pump vendor reports evaluating mission time capability. The inspectors also reviewed in-service test (IST) data for SW-P-1A and SW-P-1B to independently assess degradation trends. Interviews were held with several members of the engineering staff to assess the basis for the licensee's conclusions regarding mission time completion and the pump vendor was contacted in a phone conference with the licensee present to gain further insight into the conclusions that were reached.

The inspectors completed one sample.

b. Findings and Observations

No findings of significance were identified. The inspectors determined the licensee's evaluation of the failure mechanism regarding IGSCC was adequate and comprehensive. Examinations of the affected pump components and materials were thorough and supported the conclusion that IGSCC was the failure mechanism.

The inspector's review of pump test data and the 24 hour run conducted with SW-P-1B prior to its replacement indicated the pumps were capable of meeting their 24 hour PRA mission times. The inspectors reviewed Energy Northwest's evaluation of SW-P-1A's capability to operate for a 30 day design mission time and noted that Energy Northwest concluded that SW-P-1A was not capable of operating 30 days post-accident and completing its design function. The inspectors reviewed the licensee's failure analysis for SW-P-1A which revealed that the sand cap was extruded over the bearing housing, causing an interference with pump suction flow to the point that flow became severely degraded. This level of degradation indicated that the wear margin on contacting surfaces had been reduced to the point where performance decline was accelerating rapidly. Based on this condition, the inspectors agreed with Energy Northwest's conclusions regarding the inability of SW-P-1A to complete a 30 day design function mission time.

The inspectors also reviewed a report by the pump vendor (Flowserve) that evaluated the mission time of SW-P-1B based on its observed condition upon removal from service and the observations of SW-P-1A condition. The Flowserve report evaluated all the available pump operating data (IST results and plant computer point data) and postulated the time of shaft coupling failure as when the noticeable declining trend in performance began. The results for SW-P-1A indicated the start of a declining trend (and postulated shaft failure) occurred approximately 41 months before the rapid degradation leading to pump inoperability. Similarly, the postulated shaft failure time for SW-P-1B was determined to

be 28 months prior to its replacement. The inspectors noted that Energy Northwest's evaluation of the estimated amount of time that SW-P-1B would operate prior to the onset of rapid degradation similar to that observed in SW-P-1A was based on estimated wear rates determined from the as-found condition of SW-P-1A. The inspectors were concerned that using SW-P-1A data and estimated wear may not be consistent with the observed rate of wear in SW-P-1B. Trending of SW-P-1B performance indicated that SW-P-1B had degraded at a rate faster than SW-P-1A. Although Energy Northwest's evaluation did not provide a bounding evaluation of the estimated remaining run time of SW-P-1B, it did provide management with some degree of assurance that SW-P-1B would have also met its long term cooling mission time of 30 days. The inspector conducted an independent assessment of remaining SW-P-1B run time assuming a linear wear rate and worst case rate of degradation using noted trend data for SW-P-1B and concluded that SW-P-1B was still capable of meeting its 30 day design mission time.

See Section 4OA7.1 for a discussion of a violation identified by Energy Northwest associated with the failure to properly implement the station's operability determination Procedure PPM 1.3.66 which resulted in Energy Northwest failing to correctly assess operability of SW-P-1B. Specifically, Energy Northwest failed to correctly conclude that SW-P-1B was operable but degraded.

.2 Assessment of High Pressure Core Spray Diesel Service Water Pump (HPCS-P-2) Operability

a. Inspection Scope

The inspectors assessed the technical adequacy of the operability evaluation for HPCS-P-2 to ensure that operability was properly justified and the pump remained available such that no unrecognized increase in risk occurred. Interviews were conducted with several members of the IST and systems engineering staff to assess the basis for the licensee's conclusions regarding HPCS-P-2 operability.

The inspectors completed one sample.

b. Findings and Observations

No findings of significance were identified. The licensee identified that HPCS-P-2 could be susceptible to the same failure as SW-P-1A based on an extent of condition review conducted on October 6, 2005 documented in CR 2-05-007763. The pump was declared operable at that time based on no observed degradation in IST hydraulic performance and vibration measurements. Subsequently, CR 2-05-09906 was written on December 21, 2005 to identify a concern that the original basis for operability may have been inadequate due to HPCS-P-2 experiencing similar service conditions and maintenance history as the SW pumps, and that IST was unable to predict failure of the SW pumps. HPCS-P-2 was again determined to be operable based on satisfactory IST results and differences in design and materials between HPCS-P-2 and SW-P-1A and SW-P-1B. On January 31, 2006, CR 2-06-00719 was written to document an observed declining trend in HPCS-P-2 IST performance. The pump was again determined as operable, with a

recommendation that the issue be evaluated per PPM 1.3.67, "Effective Operational Decision Making," Revision 1. CR 2-06-00818 was generated on February 2, 2006, to tie together the previously identified issues and form the basis for performing a formal operability determination. As a result, HPCS-P-2 was declared operable but degraded.

The inspectors noted that there was considerable delay in declaring HPCS-P-2 operable but degraded. One factor for the delay was the initial exclusion of HPCS-P-2 from the extent of condition for the SW-P-1A failure due to use of an inaccurate drawing. The inspectors determined that once performed, the operability evaluation correctly characterized the HPCS service water pump as operable but degraded. Technical justification for operability based on the pump shaft and coupling design, material heat treatment and performance of similarly tempered stainless steel coupling fittings from the SW pumps provided adequate justification for operability.

.3 Other Reviewed Operabilty Evaluations

a. Inspection Scope

The inspectors: (1) reviewed plant 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. The inspectors also reviewed procedure 1.3.66, "Operability Determinations," Revision 4, to determine if the procedure met the intent of NRC Generic Letter 91-18, "Information to Licensees Regarding NRC Inspection Manual Section on Resolution of Degraded and Nonconforming Conditions," and Regulatory Issues Summary 2005-020 "Revision to Guidance Formerly Contained in NRC Generic Letter 91-18, Information to Licensees regarding Two NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions and on Operability". The inspectors evaluated Energy Northwest's application of Procedure 1.3.66 for the five operability evaluations listed below:

- PER 205-0405; Damaged Main Steam Line Supports
- PER 206-0099; MCPR Operating Limits
- PER 206-109; GE Identification of New Worst-Case Failure for Suppression Pool Temperature Analysis
- PER 206-0136; Flexible Coupling on DMA air handling units degraded
- PER 206-0138; Contacts for relay 1MR used in both emergency control room chillers are not rated for this application

The inspectors completed five samples.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

.1 IST Testing of SW-P-1A and SW-P-1B

a. Inspection Scope

The inspectors reviewed the Columbia Generating Station In-service Testing Program Plan and surveillance test procedures for SW-P-1A and SW-P-1B to determine if they were sufficient to provide assurance of continued operability. The inspectors also reviewed surveillance test results dating from the year 2000 for SW-P-1A and SW-P-1B and interviewed IST, systems engineering and design engineering personnel to assess surveillance testing organizational interfaces. Additional pump performance data (outside of the IST program) were provided to the inspectors by the licensee and were reviewed for trends. The inspectors also assessed the licensee's planned changes to the IST program since the shaft coupling failures of SW-P-1A and SW-P-1B were not detected by IST. Design basis calculations were reviewed to establish the basis for surveillance test acceptance criteria.

The inspectors completed one sample.

b. Findings and Observations

No findings of significance were identified. The inspectors determined the IST results for SW-P-1A and SW-P-1B remained acceptable prior to the failure of SW-P-1A. Additionally, the test results for SW-P-1B remained acceptable up until it was removed from service for replacement in December 2005. Although a close examination in hindsight of trends for SW-P-1B IST results showed some degree of degradation, the IST data did not indicate imminent failure. A review of IST data for 2004 and 2005 (since SW-P-1B declining trend began) showed performance below the reference curve and above the alert range. The lowest normalized data point in this period was at approximately 97 percent of reference value [95 percent is the onset of the Alert (increased monitoring) range and 93 percent is the onset of the Action (inoperable) range.]

The inspectors performed a review of other pump operating data (plant computer data normalized to the reference curve) in addition to the IST data and concluded there was an opportunity to detect a degrading trend for both SW-P-1A and SW-P-1B. This trend was not identified by the licensee based on IST data alone prior to the pump failures. Interviews with licensee personnel revealed that additional plant computer point data was normalized and plotted once SW-P-1A was confirmed to have failed. Although IST results prior to the failures were acceptable from an ASME Code compliance and Energy Northwest surveillance procedure perspective, an opportunity was missed to identify the degrading trend based on the other available information. The inspectors noted that had

plant computer data been analyzed by the licensee earlier, the onset of the degrading SW pump trends may have been detected sooner and the degraded condition of SW-P-1B may have been recognized prior to unit restart.

Interviews with licensee IST and engineering personnel indicated that no changes to the IST program for the SW pumps are planned. The licensee has chosen to inspect and refurbish the SW pumps on a periodic basis in lieu of changing the condition monitoring regimen for the pumps. The inspectors noted that vibration analysis, as it has been utilized at the site, would not have revealed the failure mechanism. The licensee stated that a vibration consultant concluded that additional vibration monitoring was not likely to yield useful information regarding the condition of SW-P-1B due to lack of baseline data and inherent difficulties with monitoring segmented shafts. However, the inspectors noted that vibration analysis using more sophisticated tools (i.e., transducer on pump bowl, phase angle analysis) may be capable of identifying similar future failures.

.2 IST Testing of HPCS-P-2

a. Inspection Scope

The inspectors reviewed the Columbia Generating Station In-service Testing Program Plan and surveillance test procedure for HPCS-P-2 to determine if they were sufficient to provide assurance of continued operability. The inspectors also reviewed surveillance test results dating from the year 2000 for HPCS-P-2 and interviewed IST, systems engineering and design engineering personnel to assess surveillance testing organizational interfaces. Additional pump performance data (outside of the IST program) were provided to the inspectors by the licensee and were reviewed for trends. The inspectors also assessed the licensee's planned changes to the IST program based on lessons learned from the SW pump failures that were not initially detected by IST.

The inspectors completed one sample.

b. Findings and Observations

No findings of significance were identified. The inspectors determined that surveillance testing for HPCS-P-2 was in compliance with ASME Code requirements. However, the inspectors also noted that testing alone may not be able to identify all failure mechanisms for the pump. The inspectors noted that surveillance testing had not been altered as a result of service water pump failures. Instead, HPCS-P-2 was placed on a 10 year refurbishment/inspection frequency per the Large Pump Preventive Maintenance plan outlined in BID PUMP-1. The addition of a time based refurbishment frequency was determined to be an appropriate complement to IST to help ensure the operational readiness of equipment important to safety. The inspectors noted that Energy Northwest performed a review of HPCS-P-2 performance data as part of the basis for evaluating HPCS-P-2 as operable but degraded (See Section 1R15.2 of this inspection report for details).

4. OTHER ACTIVITIES

4OA2 Identification and Resolution of Problems (71152)

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

Section 4OA2.2 of this report documents a problem identification crosscutting issue associated with Energy Northwest's failure to promptly identify failed service water shaft couplings in SW-P-1A and SW-P-1B.

.2 Annual Sample - Evaluation of Licensee Assessment of SW-P-1A and SW-P-1B Shaft Failures and Associated Corrective Actions and Extent of Condition

a. Inspection Scope

The inspectors reviewed Energy Northwest's evaluation of the failure of SW-P-1A which was identified on June 14, 2005, as documented in PER 205-0417. The pump had failed as a result of IGSCC and resultant failure of two of the pump shaft couplings. On December 15, 2005, SW-P-1B shaft couplings were also found to be similarly degraded during a replacement of the pump in response to the SW-P-1A pump shaft failure. The inspectors evaluated Energy Northwest's assessment of the pump failure by reviewing:

- Root cause and contributing causes of the failure
- Extent of condition to other risk significant components
- Completed and proposed corrective actions

The inspectors also conducted interviews with plant staff to: (1) evaluate the decision making process that Energy Northwest utilized to arrive at conclusions regarding inspections of SW-P-1B and restart from forced outage FO 05-01; (2) determine the adequacy of organizational interfaces and communications within Energy Northwest during forced outage FO 05-01; (3) determine the adequacy of current and planned preventive maintenance programs for risk significant systems and components; and (4) assess Energy Northwest's processes for receipt and evaluation of external and internal operating experience.

The inspectors completed one sample.

b. Findings and Observations

Procedure Adherence During FO-05 Restart Decision and Decisions Associated with Inspection of SW-P-1B Operability and Inspection

No findings of significance were identified. The team determined that the applicable managers had a good working knowledge of Procedure 1.3.67, "Effective Operational Decision Making", Revision 1. However the team noted inconsistencies in the facts and

assumptions that contributed to the decision on when to inspect/repair SW-P-1B. Examples of invalid assumptions include: (1) the decision team believed that parts were immediately available for repairs of SW-P-1B; and (2) the decision maker believed that SW-P-1B had less run time than Pump SW-P-1A.

The team noted that the use of Procedure 1.3.67 was not intended to be a substitute for performing formal operability evaluations and mainly provided recommendations of the types of information required to come to an operational decision. However, licensee personnel followed these guidelines informally, with little documentation to validate assumptions made in the decision resolution process.

The inspectors identified that the original decision making team recommended that the licensee postpone startup until inspection/repairs of SW-P-1B were completed. The final decision resolution (dated June 21, 2005) determined that SW-P-1B was fully operable and that the pump would be inspected/repaired at the next opportunity when parts became available. This final version of the decision was issued without concurrence of all of the members of the original decision making team. The inspectors noted that these actions were within the scope of Procedure 1.3.67 which states that the team should present options and recommendations to the decision maker, who makes the final determination based on the facts presented. Procedure 1.3.67 did not bind the decision maker to follow the recommendation of the decision making team.

Organizational Interface During FO-05 Restart Decision and Decisions Associated with Inspection of SW-P-1B Operability and Inspection

No findings of significance were identified. However, the inspection team concluded that Energy Northwest did not effectively address operability and pump inspection issues associated with SW-P-1B during forced outage FO-05-01. Weaknesses in areas such as organizational communications, procedure use, and changing priorities for the engineering staff, challenged the site decision making process with regard to determining the status of SW-P-1B and, ultimately, the reactor restart.

Regarding organizational communications, various parts of the organization had information that was important in assessing the status of SW-P-1B that was not shared with other parts of the organization. For example, an engineering team had documented the run times on SW-P-1A and SW-P-1B to be about the same while the management team believed SW-P-1B had less run time than SW-P-1A. The decision making team believed the required parts would be available to support an immediate inspection of SW-P-1B while the management team knew some parts would not be available for months. This was, in part, due to how the different teams defined the scope of the decision making team charter.

Although numerous engineers, supervisors, and managers were aware of the potential operability issue with regard to SW-P-1B, this information was not communicated to the control room crew. This precluded the opportunity for the on-shift SROs to make a knowledgeable operability determination for this component. These communication problems resulted in fundamentally different conclusions by the different teams. The engineering team concluded that the forced outage should be extended and the

SW-P-1B inspection be performed immediately. The management team concluded that the reactor should be started up and the inspection be performed when parts became available. The control room SRO believed the reactor could be started up and there were no issues with SW-P-1B.

The organization focused on debating the various options available for SW-P-1B and reactor startup, the merits of each option, and analyzing technical data. These activities were conducted outside the organizational processes specifically designed to deal with these types of issues. For example, the corrective action program requires a condition report be generated "to document an actual or suspected Condition Adverse to Quality." This procedure also requires all employees to notify the control room of any condition that "potentially affects equipment operability." Neither of these requirements was adhered to. Secondly, Procedure PPM 1.3.66, "Operability Determination," Revision 4, required that "Any condition which has the potential to affect the operability of an SSC is to be documented in accordance with the Corrective Action Program." The procedure also requires that "When a degraded or non-conforming condition of a specific SSC is identified, an OD should be written as soon as possible consistent with the safety importance of the SSC." A condition report was not generated nor was an operability determination performed as required. Lastly, PPM 1.3.67 was not implemented with the exception of using the decision making form as a convenient place to document what had been decided.

Corrective Action Program

No findings of significance were identified. The team determined that Procedure SWP-CAP-01, "Corrective Action Program ", Revision 9, met the intent of 10 CFR Part 50, Appendix B, Criterion XVI "Corrective Action." The team determined that the root cause of failure of SW-P-1A as documented in PER 205-0417 was adequate. However, the team concluded that the station's corrective action program was not followed in that a separate problem evaluation request was not utilized and a separate condition report written as specified in PPM 1.3.66 when Energy Northwest determined that it was likely that a similar degraded condition existed on Pump SW-P-1B. See Section 4OA7.1 for an associated violation identified by Energy Northwest.

Safety Conscious Work Environment

No findings of significance were identified. In general, the inspectors concluded the safety conscious work environment at CGS to be adequate with no noted adverse trends. Some isolated comments were noted during interviews with plant staff associated with a lack of willingness to disagree with management or take a stance that is contrary to the majority opinion.

Operating Experience Program Review

No findings of significance were identified. However, during further review Energy Northwest documented the root cause of the failure in PER 205-0417 that missed or improperly evaluated operating experience, and in one case specific actions which had been previously identified but not implemented, as a significant contributor to the failure of SW-P-1A. The inspectors evaluated the adequacy of Energy Northwest's corrective

actions associated with the station's receipt, applicability review, and evaluation of operating experience as identified in PER 205-0417. The inspectors noted that on April 6, 2006, Energy Northwest identified that three actions identified in PER 205-0417, intended to enhance the work control process with respect to operating experience, had not been formally tracked through the station's plant tracking log system or corrective action program and therefore no action had been taken. These actions included:

- Create an operating experience code for use with work orders and action requests, to allow reports and searches on operating experience related work.

- Database for evaluation, disposition and associated corrective actions for all operating experience needs to be accessible. This will enable searches on equipment types to cross check if appropriate maintenance is being done.

- Training on advanced operating experience searches on the INPO website has been provided to engineering support personnel population this cycle. Similar training should be provided to maintenance, plant health committee/long range planning, outage organization and core management/executive authorization committee personnel.

Energy Northwest documented the failure to track the actions in the corrective action program in CR 2-06-2608. The inspectors noted that the failure to formally track the actions resulted in the untimely evaluation and implementation of the identified enhancements.

The inspectors noted that since the failure of SW-P-1A that Energy Northwest conducted two quality assurance audits of the engineering and corrective action programs. These audits included limited assessments of operating experience. Additionally, the inspectors reviewed one Nuclear Safety Issues Program audit of operating experience applicability screening during the fourth quarter of 2005. The inspectors assessed the scope and adequacy of the audits. The inspectors also discussed the scope of a planned operating experience self-assessment and proposed project plan to comprehensively evaluate historical operating experience with the station's operating experience program coordinator. The inspector concluded that the audits conducted on operating experience since the failure of SW-P-1A have been of limited scope and depth. Specifically, the Nuclear Safety Issues Program audit only reviewed operating experience for adequate applicability screening for one quarter (4^{th} quarter 2005). The two quality assurance audits were of limited scope with respect to operating experience and only evaluated 36 operating experience reports combined between the two audits. The inspectors noted that although a detailed assessment of historical operating experience has not yet been conducted by Energy Northwest, Energy Northwest plans to perform an operating experience self-assessment to determine on a sampling basis the adequacy of historical operating experience screening and evaluations. Depending on the results of the self assessment, Energy Northwest has developed a project plan which may be implemented to more thoroughly assess historical operating experience.

Lastly, on a sampling basis, the inspectors independently reviewed and assessed the adequacy of other operating experience received at Columbia Generating Station to determine the adequacy of Energy Northwest's assessment of other operating experience. No significant issues were identified during the inspectors' independent review.

Preventive Maintenance Program Review

No findings of significance were identified. The inspectors reviewed licensee documents and interviewed system engineers to assess the extent of cause associated with not having performed periodic service water pump inspections since initial installation. The evaluation and observations consisted of:

- A review of a database created by Energy Northwest which consisted of preventive maintenance (PM) tasks which was established as part of a preventive maintenance optimization effort. The PM optimization was initiated as a result of internal and external assessments of the stations maintenance program prior to the failure of SW-P-1A. The database contained items such as existing PMs that have been modified or enhanced, PMs that have historically been performed as part of corrective maintenance work orders, PMs with a change in periodicity, and new PMs. The PMs identified in the database were scheduled for implementation over a four year period. The inspectors did not identify any concerns with Energy Northwest's prioritization and scheduling of the identified preventive maintenance tasks.

- A review of preventive maintenance schedules and inspection history on selected risk significant equipment including motor operated valves, switchgear and 4 kV breakers. No examples of inappropriately omitted preventive maintenance and inspection were identified.

- The inspectors interviewed six system engineers to assess the basis for preventive maintenance programs for other systems important to safety. The interviews focused on assessing the use of condition monitoring to detect degradation, use of vendor and operating experience, interfaces between system engineers and other site organizations responsible for the preventive maintenance program, significant performance trends and deficiencies, maintenance rule issues and backlog reduction issues. The inspectors noted that, in general, there had been no changes made to the preventive maintenance programs following the failure of SW-P-1A with the exception of adding time based inspections of large pumps. Many other risk significant systems (diesel generators, air compressors, etc.) had already relied on an inspection/replacement strategy for certain parts and components in addition to condition monitoring. The inspectors also noted that the preventive maintenance plans for the risk significant systems sampled were relatively mature and based heavily on vendor, users group and plant operating experience.

The inspectors noted that the system engineer was the focal point of the preventive maintenance program and interfaced with several other individuals and groups (vibration,

oil analysis, IST). The inspectors observed that several of the system engineers were new in their roles following a recent reorganization.

Failure to Promptly Identify Degradation of SW-P-1A and SW-P-1B

Introduction: A self-revealing Green NCV of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions," associated with Energy Northwest's failure to promptly identify degraded shaft coupling components in SW-P-1A and SW-P-1B was identified. A problem identification and resolution crosscutting aspect was identified with the finding due to Energy Northwest's failure to implement previously identified actions to inspect SW-P-1A and SW-P-1B in response to external operating experience (NRC Information Notice 93-68) which if implemented would have identified the onset of degradation prior to the failure of SW-P-1A.

Description: On June 14, 2005, following a start of the SW-P-1A, control room operators noted that service water flow to the Division 1 residual heat removal heat exchanger was out of specification. A subsequent surveillance test on SW-P-1A determined that pump performance had degraded and was operating at the intersection of the alert and action ranges of its performance curve. Energy Northwest declared SW-P-1A inoperable.

Energy Northwest replaced SW-P-1A with an available spare pump. During disassembly of SW-P-1A, Energy Northwest determined that the cause of the degraded pump performance was due to IGSCC of the pump shaft end flanges on two of the shaft sections. The corrosion cracking resulted in failure of the coupling between two of the shaft sections, causing the shaft to drop allowing the pump impeller to rest on the pump suction casing. This caused the impeller and suction casing to wear during operation of the pump resulting in eventual contact of the impeller hub with the pump sand cap. The sand cap, which protects the lower bearing, then deformed and cracked causing the rapid degradation in pump performance. Energy Northwest documented the pump degradation in PER 205-0417.

Energy Northwest conducted a metallurgical examination of the damaged pump shaft. In addition to the identified shaft end flange cracking, axial cracking was identified on the impeller pump shaft segment and two diagonal cracks were identified on the top column shaft. The examination also determined that the shaft material, TP410 martensitic stainless steel, had become susceptible to tempering embrittlement (shaft material was tempered at 970 degrees Fahrenheit which was conducive to tempering embrittlement). Tempering embrittlement reduced the corrosion resistance of shaft material increasing the materials susceptibility to IGSCC.

Energy Northwest determined that SW-P-1B was also susceptible to the same failure mechanism which was identified in SW-P-1A. However, SW-P-1B had not exhibited any degraded performance as determined by past surveillance test results. Energy Northwest determined that SW-P-1B was to be inspected at the earliest opportunity following procurement of repair parts which would be needed to facilitate disassembly and inspection of the pump. Corrective actions included additional monitoring of SW-P-1B to verify pump performance pending pump replacement. On December 12, 2005, Energy Northwest replaced SW-P-1B with a procured pump. A subsequent inspection of the as-found condition of SW-P-1B determined that the pump shaft had

degraded in a manner similar to SW-P-1A due to IGSCC and that the pump impeller had degraded due to wearing on the suction casing. However, wear had not progressed to the point that the SW-P-1B sand cap had been affected, therefore pump performance had not reached a point of rapid degradation.

An analysis conducted by the pump vendor, Flowserve, determined for SW-P-1A, that although pump performance had met surveillance test acceptance criteria, pump performance had slowly degraded from as early as August 2000 and as late as December 2001 as determined by a detailed evaluation of pump historical computer data. The evaluation concluded that in May 2005 the pump sand cap integrity became affected resulting in the rapid failure which was observed and eventual inoperability of the pump on June 14, 2005. Similarly, a detailed evaluation of SW-P-1B historical computer data revealed that SW-P-1B had slowly degraded since August 2003, but due to the remaining integrity of the pump sand cap, had not rapidly degraded prior to the replacement of the pump. Energy Northwest concluded that SW-P-1B, although degraded, was capable of successfully starting and operating for a minimum of 30 days post-accident to ensure completion of its design safety function and therefore concluded that SW-P-1B was operable but degraded prior to its replacement.

The inspectors reviewed applicable operating experience and noted that Energy Northwest had evaluated NRC Information Notice 93-68 which provided information regarding shaft failures associated with Byron Jackson pumps. SW-P-1A and SW-P-1B were deep draft vertical pumps manufactured by Byron Jackson. NRC IN 93-68, “Failure of Pump Shaft Coupling Caused by Temper Embrittlement During Manufacture,” dated September 1, 1993, in part, described that type 410 stainless steel used in the manufacture of Byron Jackson pump shaft couplings may have low impact strength due to inadequate heat treatment during manufacture rendering the component susceptible to tempering embrittlement. Pump shafts containing temper embrittled couplings could fail during operation if the pump has worn bearings, if the shaft is misaligned, or shaft motion is impeded by silt or debris ingestion. Energy Northwest documented the evaluation of NRC IN 93-68 in OER 84079S and PTL H104148 and determined that both SW-P-1A and SW-P-1B were to be inspected during previously scheduled pump overhauls in upcoming refueling outages R10 (SW-P-1B) and R11 (SW-P-1A). The inspectors noted that although the action to inspect both service water pumps was documented in OER 84709S, the action was not tracked as a required corrective action. Subsequently, the planned inspections of SW-P-1A and SW-P-1B were deferred from R10 and R11 without consideration for the evaluation of IN 93-68. Additionally, later inspections of SW-P-1A planned for refueling outages R-13 and R-17 and an inspection of SW-P-1B in refueling outage R-12 were again deferred. Although the inspections planned for R-12, R-13, and R-17 provided opportunities for Energy Northwest to inspect either service water pump and identify the conditions described in IN 93-68, these later inspections were not planned specifically to address IN 93-68.

The inspectors also noted an additional missed opportunity to identify the failed shaft couplings due to inadequately evaluated operating experience. Specifically, NRC IN 94-45, “Potential Common-Mode Failure Mechanism for Large Vertical Pumps,” dated June 17, 1994, described a problem where differing coupling materials could experience galvanic corrosion resulting in a failure of the shaft coupling and subsequent failure of long shaft vertical pumps. Energy Northwest documented their evaluation of IN 94-45 in

OER 82008Y and PTL H102543. The evaluation concluded that since the shaft coupling materials for the SW pumps were all type 410 stainless steel, galvanic corrosion was not a concern and closed the evaluation with no action taken. However, the inspectors noted that in addition to IN 94-45 specifically addressing galvanic corrosion of shaft couplings, it also generally addressed a concern that current testing methodologies of vertical line shaft pump hydraulic and mechanical performance may not identify, before damage occurs, interference between the pump impellers and bowls caused by a change in shaft length. The inspectors considered Energy Northwest's evaluation of IN 94-45 to be narrowly focused and a missed opportunity to establish periodic inspections of the service water pumps which would ensure, in conjunction with condition monitoring, that an adequate preventative maintenance plan was established for the pumps.

The inspectors considered Energy Northwest's failure to implement actions to inspect SW-P-1A and SW-P-1B as documented in OER 84079S or periodically as part of an adequate preventative maintenance plan as a failure to promptly identify a condition adverse to quality. Specifically, an inspection of the pump shaft during the previously mentioned scheduled inspections in response to external operating experience or for preventative maintenance would have identified the onset of IGSCC or shaft coupling failure prior to the condition revealing itself with the failure of SW-P-1A on June 14, 2005, and the replacement of SW-P-1B on December 12, 2005.

Analysis: The failure to inspect SW-P-1A and SW-P-1B in response to NRC IN 93-68 or as part of an adequate preventive maintenance program was a performance deficiency. The finding was more than minor risk significance because it was an equipment reliability issue which impacted the mitigating systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Utilizing MC 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations," Phase 1 worksheet, the inspectors concluded that the finding was of very low risk significance (Green), because the finding did not result in a loss of safety function of SW-P-1A, did not result in a loss of safety function of the system, did not represent a loss of safety function of non-technical specification equipment, and did not screen as potentially risk significant due to external events. The cause of the finding was related to the crosscutting element of problem identification and resolution because of Energy Northwest's failure to implement actions to inspect SW-P-1A and SW-P-1B as determined in Energy Northwest's evaluation of IN 93-68.

Enforcement: 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires in part that conditions adverse to quality be promptly identified and corrected. Contrary to this requirement Energy Northwest failed to promptly identify degraded shaft couplings in SW-P-1A and SW-P-1B. Specifically, in response to IN 93-68, Energy Northwest identified in 1994 that both pumps were to be inspected to determine if the pump shaft couplings were adversely affected by tempering embrittlement. The failure to inspect SW-P-1A or SW-P-1B from 1994 until the failure of SW-P-1A on June 14, 2005, and the replacement of SW-P-1B on December 12, 2005, was considered to be a violation of Criterion XVI. Because this finding was of very low safety significance and entered into the licensee's corrective action program as PER 205-0417, this violation is being treated as an NCV, consistent with Section VI.A of the Enforcement Policy

(NCV 05000397/2006011-01, Failure to Promptly Identify Degraded Shaft Couplings in Standby Service Water Pumps). Energy Northwest implemented corrective actions to ensure periodic future inspections of both SW-P-1A and SW-P-1B to ensure the operational readiness of the standby service water system pumps.

.3 Annual Sample - Evaluation of Licensee Assessment of HPCS-P-2 and Corrective Actions

a. Inspection Scope

The inspectors reviewed the licensee's corrective actions for the HPCS service water pump (HPCS-P-2) not being inspected since initial installation. The licensee's schedule for repairing or replacing the HPCS service water pump, including the schedule for receipt of necessary parts, was assessed for timeliness and completeness. The inspectors also reviewed the application of lessons learned from the service water pump failures to Energy Northwest's evaluation of HPCS-P-2. The inspectors reviewed corrective action program documents, maintenance work order scheduling, and interviewed licensee staff.

The inspectors completed one sample.

b. Findings and Observations

No findings of significance were identified in this area. The inspectors determined the licensee's Preventive Maintenance Background Information Document (BID-PUMP-1) was revised to require an initial inspection and subsequent inspections on a 10 year periodicity for HPCS-P-2 as a corrective action for the lack of preventive maintenance to date. The inspectors noted that BID-PUMP-1 indicated that HPCS-P-2 was to be inspected "as soon as possible." However, the inspector's review of Energy Northwest's schedule of maintenance for HPCS-P-2 indicated that an inspection of HPCS-P-2 was not to occur until May 2007 during refueling outage R-18. The inspectors reviewed Decision Resolution (CR No. 2-06-00818, PER 206-0042, Rev. 1 dated April 7, 2006) to defer inspection of HPCS-P-2 until R-18. The basis for deferral was due to the increased risk to core damage due to the accrued unavailability of HPCS-P-2 during an inspection or replacement with the station at power. The inspectors noted that although the basis of deferral was adequate, Energy Northwest had not considered inspecting HPCS-P-2 in the event of a forced outage prior to refueling outage R-18. Based on the inspectors observation, Energy Northwest subsequently included HCPS-P-2 in their forced outage work scope.

The inspectors determined that Energy Northwest adequately assessed HPCS-P-2 with regard to lessons learned from the shaft coupling failures of SW-P-1A and SW-P-1B (i.e. coupling design, material heat treatment, potential for IGSCC). Energy Northwest concluded that HPCS-P-2 was less susceptible to the same failure mechanism. The inspectors noted that an operability evaluation was documented, in contrast with the handling of SW-P-1B. This operability evaluation, however, was not performed at the time of discovery of the failure of SW-P-1A. Delays in identifying HPCS-P-2 as susceptible during the extent of condition review for the SW-P-1A failure and detection of a degrading trend in IST results delayed identification of HPCS-P-2 as an operability

concern. Initiation of a formal determination of “operable but degraded” did not occur until CR 2-06-00818 was initiated by the System Engineer on February 2, 2006.

4OA5 Other Activities

.1 (Closed) URI 05000397/2005003-01; Service Water Pump A Performance Degradation

This URI was opened pending an NRC review of the performance issues associated with identified degradation of SW-P-1A. Specifically, SW-P-1A had failed as a result of IGSCC and resultant failure of its pump shaft couplings. The URI was opened pending an NRC staff review of Energy Northwest’s evaluation of: (1) the ability of SW-P-1A to complete it’s design mission time given the as-found condition of the pump; and (2) the as-found condition of SW-P-1B following the planned pump inspection at the next available opportunity.

See Section 4OA2.2 of this report for details regarding the inspectors completed review of performance deficiencies and associated enforcement actions, assessment of Energy Northwest’s evaluation of operability of SW-P-1A and the as-found condition of SW-P-1B following its replacement on December 12, 2005.

4OA6 Meetings, Including Exit

On April 27, 2006, the team leader conducted a debrief of the preliminary inspection results to Mr. V. Parrish and other members of his staff. The team leader confirmed that the inspectors were provided with information that the licensee considered to be proprietary. This information was associated with the vendor provided as found measurements of SW-P-1A and SW-P-1B pump internals.

On June 1, 2006, the team leader presented the inspection results to Mr. D. Atkinson and other members of his staff. No additional proprietary information was received by the inspectors.

4OA7 Violations Identified by Energy Northwest

.1 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," states, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings." Section 2.0 of procedure PPM 1.3.66, “Operability Determinations,” Revision 4, provides guidance for operability determinations. Section 2.1 provided, “Any condition which has the potential to affect the operability of an SSC is to be documented in accordance with the Corrective Action Program (SWP-CAP-01).” Section 2.3 provided, “Determining SSC operability is a continuous process. Whenever the ability of an SSC to perform its specified function is called into question, operability must be determined from an examination of the ability of the SSC to meet its specified safety function(s).” Section 2.4 provided, “When a degraded or non-conforming condition of specific SSCs is identified, an operability determination should be written as soon as possible consistent with the safety importance of the SSC. Given that SW-P-1B had a similar operating history, identical operating environment, and improper shaft material tempering as SW-P-1A,

SW-P-1B should have been identified as operable but degraded because: (1) past successful surveillance testing and no discernable adverse trend indicated that SW-P-1B was capable of meeting its design safety function and provided a reasonable expectation that the pump was operable; and (2) the evidence that SW-P-1B should be affected similar to SW-P-1A as discussed above which placed full qualification of SW-P-1B into question. Contrary to these requirements, since June 18, 2005, until SW-P-1B was replaced in December 2005, operability of SW-P-1B was not properly classified as operable but degraded, and a formal operability determination was not performed as required by procedure PPM 1.3.66. This was considered to be a violation of Criterion V.

This finding is greater than minor since it is associated with the equipment performance attribute of the mitigating systems cornerstone and directly affects the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events. Specifically, failing to accurately assess operability of a safety-related component is not commensurate with ensuring the reliability and capability of the component to perform its design safety function. Using the Phase 1 worksheet in Manual Chapter 0609, "Significance Determination Process," the finding is of very low safety significance since: (1) it did not represent a qualification deficiency confirmed not to result in loss of function per GL 91-18; (2) it did not represent a loss of system safety function; and (3) it did not represent a loss of function of non-technical specification risk significant equipment or screen as potentially risk significant due to a seismic, flooding or severe weather event. Energy Northwest took corrective actions which included assessments by external organizations (consultants) to evaluate station organizational and communication breakdowns, and knowledge and implementation of operability determinations as it relates to NRC Generic Letter 91-18 and NRC Regulatory Issues Summary 2005-020. The consultant's conclusions included identification that Energy Northwest had misapplied the operability determination process when the station concluded that SW-P-1B was operable and fully qualified when supporting information indicated that the pump was operable but degraded. Energy Northwest documented the conclusions of the consultants findings in CR 2-06-00363.

ATTACHMENT: Supplemental Information

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Energy Northwest

D. Atkinson, Vice President, Nuclear Generation
J. Bartholomew, System Engineer
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S. Belcher, Manager, Operations
S. Boynton, Manager, Systems Engineering
D. Coleman, Manager, Performance Assessment and Regulatory Programs
G. Cullen, Licensing Supervisor, Regulatory Programs
K. Engbarth, Supervisor, Corrective Action Program
M. Holle, System Engineer
A. Khanpour, General Manager, Engineering
W. LaFramboise, Manager, Technical Engineering
T. Lynch, Plant General Manager
W. Oxenford, Vice President, Technical Services
J. Parrish, Chief Executive Officer
R. Torres, Manager, Quality Assurance and Corrective Action Programs
C. Whitcomb, Vice President, Organizational Performance and Staffing

NRC Personnel

C. Johnson, Chief, Project Branch A, Division of Reactor Projects
Z. Dunham, Senior Resident Inspector
A. Vegel, Deputy Director, Division of Reactor Projects

ITEMS OPENED AND CLOSED

Items Opened, Closed, and Discussed During this Inspection

Opened

None

Opened and Closed

05000397/2006011-01	NCV	Failure to Promptly Identify Degraded Shaft Couplings in Standby Service Water Pumps (Section 4OA2.2)

Closed

05000397/2005003-01	URI	Service Water Pump A Degradation (Section 4OA5.1)

Discussed

None.

PARTIAL LIST OF DOCUMENTS REVIEWED

Procedures

PPM 1.3.66; Operability Determination; Revision 4

PPM 1.3.67; Effective Operational Decision Making procedure; Revision 1

OSP-SW/IST-Q701, Standby Service Water Loop A Operability Surveillance Procedure; Revisions 11 and 12

OSP-SW/IST-Q702; Standby Service Water Loop B Operability Test; Revisions 11 and 12

OSP-SW/IST-Q703; HPCS Service Water Operability Test; Revision 7

SWP-CAP-01; Corrective Action Program; Revision 9

SWP- CAP-02; Cause Determination; Revision 3

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

SWP-CAP-05; Restart Evaluation Process; Revision 2

Calculations

ME-02-92-43; Room Temp Evaluation for Diesel Generator Building, Reactor Building, Rad-Waste Building, and Service Water Pumphouse; Revision 7

ME-02-93-05; Calculation for RHR Heat Exchanger Performance; Revision 1

Drawings

02E22-13,5; CVI Drawing for HPCS-P-2; Revision 4

Miscellaneous

Flowserve Document Number ER-1173; Evaluation of SW-P-1B Service Water Pump Operability Energy Northwest, Columbia Generating Station, Model 28 KXH 3 Stage; January 20, 2006

LaBlond & Associates, LLC, Investigation of 1B Service Water Pump's Treatment from June to December, 2005

American Society of Mechanical Engineers (ASME) Codes; Section XI

Nuclear Regulatory Commission Generic Letter GL-91-18; Resolution of Degraded and Non-Conforming Conditions

ASME/ANSI, Operations and Maintenance, Part 6

Decision Resolutions; CR-0417; June 20, 2005 / June 21, 2005 / August 4, 2005

Interoffice Memorandum; Flowserve Evaluation of SW-P-1B SW Pump; January 25, 2006

Interoffice Memorandum; Reevaluation of Extent of Condition For the SW Pump Shaft Coupling Failures; January 31, 2006

Risk Significance Evaluation of Service Water Pump 1B Coupling Flange Failure; Revision 1

Risk Significance Evaluation of Service Water Pump 1A Coupling Flange Failure; Revision 0

Interoffice Memorandum; Failure Analysis of SW-P-1B; December 29, 2005

BID-PUMP-1; Preventive Maintenance Background Information - Large Pumps; Revision 2

CGS IST Program Plan (Pumps & Valves) - 3rd Interval

TR-106857-V12; EPRI PM Basis, Vol.12: Vertical Pumps; July 97

AXS48153; Pump Assembly (HPCS-P-2); Revisions 4 and 5

Pacific Pumps, Inc. Parts List, Order No. V48249

MC-1568; Materials of Construction, WPPS-2, Stby SW Pump

V167514; Carpenter Tech Cert of Tests SW-P-1A - BJ Pump Co.; February 12, 1975

V167514; Carpenter Tech Cert of Tests SW-P-1B - BJ Pump Co.; February 12, 1975

62981; Carpenter Tech Cert of Tests HPCS-P-2 - Dresser Ind.; February 18, 1974

P.O. 0031966; Flowserve Report As-Found Condition and Repair Plan for SW-P-1A; July 26, 2005

P.O. 320454; Flowserve Report As-Found Condition for SW-P-1A; January 12, 2006

Condition Reports

2-05-05983	2-06-00363	2-05-06068	2-05-06147	2-05-07771	2-05-06147
2-05-07763	2-05-09906	2-06-00719	2-06-00818	2-06-03078	

Problem Evaluation Reports

205-0417	206-0138	206-0099	205-0405	206-0109	206-0179
206-0136	205-0716	206-0042			