ENERGY NORTHWEST

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GO2-10-044

10 CFR 50.73

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555-0001

Subject: **COLUMBIA GENERATING STATION, DOCKET NO. 50-397**
LICENSEE EVENT REPORT NO. 2009-002-01

Dear Sir or Madam:

This submittal provides an update to Licensee Event Report No. 2009-002-00 which reported a reactor scram event at Columbia Generating Station on May 8, 2009. This revision updates the root cause for the event based on a recent re-evaluation of the event.

There are no commitments being made to the NRC herein. If you have any questions or require additional information, please contact Mr. M.C. Humphreys at (509) 377-4025.

Respectfully,

W.S. Oxenford
Vice President, Nuclear Generation & Chief Nuclear Officer

Enclosure: Licensee Event Report 2009-002-01

cc: NRC Region IV Administrator
NRC NRR Project Manager
INPO Records Center
NRC Sr. Resident Inspector – 988C (2)
R.N. Sherman – BPA/1399
W.A. Horin – Winston & Strawn
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IE22

NRR

NRC FORM 366 (9-2007) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104 EXPIRES 08/31/2010

Estimated burden per response to comply with this mandatory collection request: 80 hours. Reported lessons learned are incorporated into the licensing process and fed back to industry. Send comments regarding burden estimate to the Records and FOIA/Privacy Service Branch (T-5 F52), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, or by internet e-mail to infocollects@nrc.gov, and to the Desk Officer, Office of Information and Regulatory Affairs, NEOB-10202 (3150-0104), Office of Management and Budget, Washington, DC 20503. If a means used to impose an information collection does not display a currently valid OMB control number, the NRC may not conduct or sponsor, and a person is not required to respond to, the information collection.

LICENSEE EVENT REPORT (LER)

(See reverse for required number of digits/characters for each block)

1. FACILITY NAME	2. DOCKET NUMBER	3. PAGE
Columbia Generating Station	05000397	1 OF 3

4. TITLE

Manual Reactor Scram due to Loss of Hydrogen Pressure in the Main Generator

5. EVENT DATE			6. LER NUMBER			7. REPORT DATE			8. OTHER FACILITIES INVOLVED	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REV NO.	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER 05000
05	08	2009	2009	– 002 –	01	03	17	2010	FACILITY NAME	DOCKET NUMBER 05000

9. OPERATING MODE
1

10. POWER LEVEL
087

11. THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: *(Check all that apply)*

☐ 20.2201(b)	☐ 20.2203(a)(3)(i)	☐ 50.73(a)(2)(i)(C)	☐ 50.73(a)(2)(vii)
☐ 20.2201(d)	☐ 20.2203(a)(3)(ii)	☐ 50.73(a)(2)(ii)(A)	☐ 50.73(a)(2)(viii)(A)
☐ 20.2203 (a)(1)	☐ 20.2203(a)(4)	☐ 50.73(a)(2)(ii)(B)	☐ 50.73(a)(2)(viii)(B)
☐ 20.2203(a)(2)(i)	☐ 50.36(c)(1)(i)(A)	☐ 50.73(a)(2)(iii)	☐ 50.73(a)(2)(ix)(A)
☐ 20.2203(a)(2)(ii)	☐ 50.36(c)(1)(ii)(A)	☒ 50.73(a)(2)(iv)(A)	☐ 50.73(a)(2)(x)
☐ 20.2203(a)(2)(iii)	☐ 50.36(c)(2)	☐ 50.73(a)(2)(v)(A)	☐ 73.71(a)(4)
☐ 20.2203(a)(2)(iv)	☐ 50.46(a)(3)(ii)	☐ 50.73(a)(2)(v)(B)	☐ 73.71(a)(5)
☐ 20.2203(a)(2)(v)	☐ 50.73(a)(2)(i)(A)	☐ 50.73(a)(2)(v)(C)	☐ OTHER
☐ 20.2203(a)(2)(vi)	☐ 50.73(a)(2)(i)(B)	☐ 50.73(a)(2)(v)(D)	Specify in Abstract below or in NRC Form 366A

12. LICENSEE CONTACT FOR THIS LER

FACILITY NAME	TELEPHONE NUMBER *(Include Area Code)*
Donald W. Gregoire, Engineering Specialist	509-377-8616

13. COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT

CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX
B	TI	FLT	A218	Y					

14. SUPPLEMENTAL REPORT EXPECTED	15. EXPECTED SUBMISSION DATE	MONTH	DAY	YEAR
☐ YES *(If yes, complete 15. EXPECTED SUBMISSION DATE)* ☒ NO				

ABSTRACT

On May 8, 2009 at 1046 hours, a manual reactor scram was inserted while Columbia was operating in Mode 1 at 87% power. Loss of air side seal oil pressure and consequential loss of hydrogen pressure in the main generator occurred during testing of the seal oil system backup regulator and air side seal oil back up pump. When the backup system was activated, a crud burst of corrosion products from the back up oil supply line and biological growth from the heat exchanger plugged the single in-line filter. This caused a loss of air side seal oil pressure, allowed hydrogen to escape from the generator, and necessitated the manual scram.

The process for addressing compensatory measures for the single point vulnerability of the Cuno filter (SO-F-1) was inadequate (Root Cause 1). An ineffective and untimely repair of Seal Steam flange leaks contributed to increased levels of moisture in the air side seal oil system. This resulted in formation of corrosion products and biodegradable material in the seal oil system (Root Cause 2).

Interim risk mitigation actions to monitor the in-line filter continuously during backup system operation and seal oil system startup and take actions as necessary are being established in plant operating procedures. The seal oil filter upgrade is scheduled to be implemented during the next refueling outage (R-20).

No similar events have been reported by Energy Northwest.

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NARRATIVE

Plant Condition

The plant was operating in Mode 1 at 87% power at the time of this event.

Event Description

On May 8, 2009, operations personnel were testing the seal oil system [TI] back up regulator [RG] and air side seal oil back up pump [P]. The system operated on the back up regulator for approximately three minutes before the air side seal oil system pressure dropped to zero. The loss of air side seal oil resulted in a failure of the hydrogen side seal to maintain generator pressure. Hydrogen gas, initially pressurized to approximately 72 psi, escaped through the shaft seals into the turbine building. Due to the release of hydrogen from the generator [GEN], a manual scram of the reactor [RCT] was inserted at 1046 PDT and the turbine building was evacuated. This event occurred 13 hours prior to a planned shutdown for a refueling outage (R-19) with the plant in an end of cycle final feedwater temperature reduction (FFTR) lineup.

All control rods fully inserted in response to the reactor protection system (RPS) actuation. A reactor pressure vessel [RPV] water low level (level 3) trip occurred with a minimum level of -4.7 inches. One reactor feedwater (RFW) pump was manually tripped prior to level recovery and the FFTR lineup was exited. The long stroke time of the bypass valve for the high pressure feedwater heaters caused the other RFW pump to trip due to RPV high level (level 8). The pump was restarted and RPV water level control was established at 36 inches. Heat removal through the main condenser [SG] was maintained. Post trip RPV water level was maintained in the normal band using the feedwater [SJ] and condensate systems [SD]. RPV pressure was controlled using automatic control of the main turbine [TRB] bypass valves. Off-site power was available and two of three emergency diesel generators [EK] were operable and available. DG-2 was inoperable and unavailable due to DG-2 fire remote transfer switch functional operability surveillance testing. No other safety systems actuated or were required to actuate. There was no inoperable equipment at the start of the event that contributed to the event.

At 1741 EDT (1441 PDT), the NRC was notified of the RPS actuation per 10 CFR 50.72(b)(2)(iv)(B) (reference event notification number 45051). This LER is submitted pursuant to 50.73(a)(2)(iv)(A) as an event or condition that resulted in manual actuation of the RPS.

Immediate Corrective Action

Maintenance actions on DG-2 were stopped and the generator was placed in an inoperable but available status. Plant cooldown was slowed through steam load reduction. Venting of the main generator was completed. The inline seal oil filter, capable of on-line cleaning by rotating the cleaning handle, was cleared and seal oil system pressure was restored. Due to imminent refueling outage, no attempt to restart the plant was made.

Cause

The direct cause of this event was accumulated corrosion products on backup seal oil piping and biological material in the air side seal oil cooler, both due to higher than normal moisture in the oil over the past two years. These materials were released during system backup testing, which plugged the in-line seal oil system filter. Seal oil pressure dropped downstream of the plugged filter.

Two root causes were identified: 1) The process for addressing compensatory measures for the single point vulnerability of the Cuno filter (SO-F-1) was inadequate. 2) An ineffective and untimely repair of Seal Steam flange leaks contributed to increased levels of moisture in the air side seal oil system. This resulted in formation of corrosion products and biodegradable material in the seal oil system.

Further Corrective Action

The following actions are being pursued to prevent recurrence: 1) Seal oil system procedures are being upgraded to ensure the single in-line filter is monitored continuously during seal oil system startup, backup system testing, or alarm for low air side seal oil pressure or backup system activation. Actions will be taken as necessary to clear the filter. 2) Methods, criteria and preventive maintenance that tests turbine seal oil for biological contaminants will be established. This includes monitoring and addressing conditions that lead to bio-fouling and corrosion.

Additional corrective actions to address contributing causes, extent of cause, and recurrence prevention include procedure revisions, leak repairs to restore oil moisture to normal, PM additions and clarifications, and training enhancements.

Assessment of Safety Consequences

For this event, High-Pressure Core Spray (HPCS) [BG], Low-Pressure Core Spray (LPCS) [BM], Reactor Core Isolation Cooling (RCIC) [BN], and Residual Heat Removal (RHR)/Low Pressure Coolant Injection (LPCI) [BO] systems were capable of performing their intended safety functions. Off-site power was available and two of three emergency diesel generators [EB and EK] (one for Division I & II and one for Division III) were operable and available. The other emergency diesel generator was not operable but available fourteen minutes after the event. This event did not involve an event or condition that could have prevented the fulfillment of any safety function described in 10 CFR 50.73(a)(2)(v). This event posed no threat to the health and safety of the public or plant personnel and was therefore, not safety significant.

Similar Events

No similar events have been reported by Columbia. Review of the corrective action program database from 2003 to present reveals no documented issues of moisture problems in seal oil prior to October 2007, at which point they became frequent. Moisture content increased by an order of magnitude, roughly 20 ppm to 200 ppm. This exposure is believed to have accelerated corrosion of carbon steel piping and vessels, increased sludge formation in the oil, and provided conditions more conducive to biological growth. Consequently, corrosion products and biological growth have developed and accumulated over the past two years in significantly higher quantity than previously experienced at Columbia.

Energy Industry Identification System (EIIS) Information

EIIS codes from IEEE Standards 805-1984 and 803-1983 are denoted as [X], [XX], or [XXX] throughout the body of the narrative.