ENERGY NORTHWEST

W. Scott Oxenford
Columbia Generating Station
P.O. Box 968, PE08
Richland, WA 99352-0968
Ph. 509.377.4300 | F. 509.377.4150
soxenford@energy-northwest.com

March 16, 2010
GO2-10-045

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. 2009-003-01

Dear Sir or Madam:

This submittal provides an update to Licensee Event Report No. 2009-003-00 which reported a reactor scram event at Columbia Generating Station on June 26, 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 2009-003-01

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
W.C. Walker – NRC RIV/fax

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 5

4. TITLE

Manual Reactor Scram due to a Fire Stemming from a Turbine Lube Oil leak

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
06	26	2009	2009	– 003	–01	03	16	2010	FACILITY NAME	DOCKET NUMBER 05000

9. OPERATING MODE
1

10. POWER LEVEL
75

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
D	TD	VX	W120	N	X	TD	PS	S254	N

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

ABSTRACT

At 1949 on June 26, 2009, with Columbia operating at approximately 75% power, a small fire near the #2 high pressure turbine bearing was reported to the main control room. As directed by procedure, a manual scram was inserted at 1952.

The in-service turbine lube oil vapor extractor system did not provide enough differential pressure to prevent lube oil from leaking out of the bearing pedestal. The fire occurred when the leaking lube oil came into contact with a hot pipe causing the oil to flash.

The root causes were an out of calibration pressure switch and the integrated system knowledge of the main turbine lube oil exhauster system by Operations and Engineering was weak. The pressure switch has been replaced. Additional corrective actions taken to prevent recurrence include revisions to station procedures to ensure that the turbine lube oil vapor extractor system pressure is monitored via independent instruments during routine operator rounds as well as after any system manipulation. In addition, improvements in training for Operations and Engineering are planned to increase overall system knowledge.

No similar events have been reported by Energy Northwest.

1. FACILITY NAME	2. DOCKET	6. LER NUMBER			3. PAGE
		YEAR	SEQUENTIAL NUMBER	REV NO.	
Columbia Generating Station	05000397	2009	003	01	2 OF 5

NARRATIVE

Plant Condition

At the beginning of the time line described below, the plant was in Mode 1 at 43% power and was conducting startup activities. Power was raised to just above 75% at 0525 on 6/26/09 and remained at that approximate power level until the manual scram was initiated at 1952 on 6/26/09.

Event Description

On 6/25/09, between 0840 and 0900, two separate activities were conducted by personnel from maintenance and operations involving manipulations of the turbine lube oil [TD] system. The two activities performed in parallel were coincidental in timing, not intentional. The following activities are presented in the approximate sequence of events derived from alarm logs and interviews with the respective personnel:

- Maintenance personnel were setting up to replace the Return Oil Basket Strainer [BSKT] for the turbine lube oil tank [TK] when the equipment operator arrived to support a swap of vapor extractors [VX].
- Operations secured the in-service turbine lube oil vapor extractor, TO-EX-1B, in order to support the start of the other lube oil vapor extractor, TO-EX-1A. TO-EX-1A was being started to support a post maintenance test for the discharge valve of this vapor extractor. Maintenance noted an increase in oil overflow out of the basket strainer cover when TO-EX-1B was secured.
- TO-EX-1A tripped a few seconds after being started.
- TO-EX-1B was restarted by Operations personnel in the main control room, and the equipment operator in the field repositioned the inlet and outlet valves to the vapor extractor as per the normal operating procedure. Maintenance noted that the rate of oil overflow did not diminish when TO-EX-1B was restarted.
- Maintenance removed the clogged basket strainer, noting that the oil overflow subsided after this action was taken.
- The control room received a high demister differential pressure (dP) alarm (TG OIL RESVR DEMISTER ΔP HI) [PA] and directed the equipment operator in the field to adjust the valve alignment to clear the alarm. The high dP condition was cleared following adjustment of the TO-EX-1B discharge valve.
- When Maintenance completed the replacement of the Return Oil Basket Strainer, the lid on the tank was closed resulting in an exhauster low output pressure condition. However, no low pressure alarm was received.

At this juncture, with no system alarms present, Operations believed the turbine lube oil vapor extractor system had been properly restored to service. Subsequent investigation determined that the pressure switch [PS] that provides a signal to the vapor exhauster low pressure alarm was out of calibration low. This resulted in Operations being unaware that the differential pressure provided by the turbine lube oil vapor extractor system was inadequate to preclude lube oil leakage at the high pressure turbine bearing #2.

The plant was manually scrammed at 1952 on 6/26/09 after the Control Room was notified of discovery of a small fire on a flange below turbine bearing #2 at 1949.

The plant response to the manual scram was as expected except for the following:

- When Reactor Core Isolation Cooling (RCIC) [BN] was initiated at 2015 on 6/26/09 to assist in reactor vessel level control, one of the valves did not open automatically. The valve was successfully opened by Operations via the control switch.

- When attempting to transfer control of reactor pressure vessel level a Reactor Feedwater [SJ] heater outlet isolation valve would not close (first attempt to close the valve occurred at 2001 on 6/26/09). An alternate valve lineup was established to facilitate level control at 2017 on 6/26/09.

There was no inoperable equipment at the start of the event that contributed to the event. This LER is submitted pursuant to 50.73(a)(2)(iv)(A) as an event or condition that resulted in manual actuation of the Reactor Protection System.

Cause

The sustained bearing lube oil leak was caused by less than adequate (LTA) negative sump pressure, i.e. inadequate delta pressure across the bearing. The LTA negative sump pressure condition was caused by insufficient flow through the in-service vapor extractor. One operating extractor is required to maintain the negative sump pressure.

The inability of the plant staff to identify the low output from the extractor system, and subsequently the LTA negative sump pressure, was due to an out of calibration low pressure switch [PS] and has been identified as Root Cause 1 (RC1). The pressure switch is designed to provide a low pressure alarm at 0.25 inches water column (wc) decreasing. Investigation after the event determined the as-found setpoint to be 0.11 inches wc. The pressure switch was last calibrated on 3/25/07 and found to be within calibration tolerance at that time. With this alarm being out of calibration low, none of the subsequent operations crews were directed to the alarm response procedure which had the following caution: "Operating the Main Turbine without a vapor extractor may cause oil leakage from the #1 and #2 bearings. This oil leakage may lead to a fire in the High Pressure Turbine area." The pressure switch was recalibrated on 6/28/09 and was subsequently replaced with a different switch on 8/16/09.

The cause for TO-EX-1B not providing sufficient negative pressure was determined to be the discharge valve throttled to an almost closed position. It is unclear if the valve's final position was the result of equipment condition (i.e. an absent roll pin) and system perturbations which effectively closed the valve or if it was the as left condition by the operator. Both paths were explored as part of the investigation.

Post event inspections noted that the TO-EX-1B discharge valve was missing the handle to shaft roll pin. The absent roll pin could allow the butterfly valve to close in response to system perturbations resulting from the strainer basket change out. During post event investigation the valve was successfully manipulated prior to repair but performance was not consistent. This does not guarantee that the disc would remain in the as-left orientation. The valve was repacked in May 2003 with no subsequent work history to indicate how or why the pin was missing. The valve was repaired on 6/29/09.

The equipment operator manipulated the valves on 6/25/09 to restore TO-EX-1B to service after TO-EX-1A had tripped off to achieve the appropriate system pressure as directed by the operating procedure. During this same time frame, maintenance personnel were changing out a clogged Return Oil Strainer Basket which impacted the differential pressure of the system. It should be noted that post event investigation identified that lifting the cover of the strainer basket does cause system pressure indications to change. After the initial restoration of TO-EX-1B, the high dP alarm was received and the Control Room directed the equipment operator to manipulate the valve alignment to clear the alarm. The alarm response procedure does not have any direction or requirements to monitor system pressure after valve adjustments are made. The valves were left in a position which cleared the alarm. No follow-up monitoring of the vapor extraction system pressure was performed, which includes the lack of routine monitoring as this parameter is not included in the regular turbine building equipment operator rounds. The combination of making system adjustments while the strainer was being replaced, operation of the discharge valve with the missing roller pin yielding inconsistent system flows when set at the same position, and the system low pressure alarm being out of calibration low (see RC1 above) contributed to the likelihood that Operations personnel were unaware that there was less than adequate negative sump pressure after the above described system manipulations.

Root Cause 2 (RC2) has been determined to be weaknesses in integrated system knowledge of the main turbine lube oil exhauster system by Operations and Engineering. The exhauster operations concurrent with main lube oil strainer cleaning caused the system to be placed in a condition in which it was not performing its intended function. Once this condition was established, it was not recognized by Operations or Engineering personnel.

Further Corrective Action

The following actions have been or are being pursued to prevent recurrence:

1) Procedures have been revised to require the as-left system pressure indications be confirmed after any manipulation of the vapor extractor suction or discharge valves. Cautions to these procedures were also be added to ensure adjustments are not made to the vapor extractor suction or discharge valves when the cover is removed from the Return Oil Basket Strainer.

2) The turbine building rounds procedure has been revised to check lube oil vapor extraction system pressure each shift.

3) Improvements in Engineering and Operations lube oil exhauster training will be implemented.

Additional corrective actions to address contributing causes, extent of cause, and recurrence prevention include PM additions and clarifications such as the evaluation of the conditions and frequency for performing pressure switch calibrations, procedure revisions, and training material enhancements.

Assessment of Safety Consequences

For this event, High-Pressure Core Spray (HPCS) [BG], Low-Pressure Core Spray (LPCS) [BM], RCIC, 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 all three of the emergency diesel generators [EB and EK] were operable and available. 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. A review of the Corrective Action Program CR database found no repeat occurrences of this event. Two Problem Evaluation Reports were found which identified cases of oil mist coming from TO-EX-1B when in standby condition. In both cases the leaking condition was repaired. The corrective actions taken for the previous events have no application to the subject event.

Energy Industry Identification System (EIIS) Information

EIIS codes are bracketed [ ] where applicable in the narrative.