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March 27, 2006

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

Subject: Licensee Event Report 50-458 / 06-002-00
River Bend Station – Unit 1
Docket No. 50-458
License No. NPF-47

File Nos. G9.5, G9.25.1.3

RBG-46551
RBF1-06-0060

Ladies and Gentlemen:

In accordance with 10CFR50.73, enclosed is the subject Licensee Event Report. This document contains no commitments.

Sincerely,

David N. Lorfing
Manager – Licensing

DNL/dhw
Enclosure

IE22

cc: U. S. Nuclear Regulatory Commission
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NRC FORM 366 (6-2004)	U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB: NO. 3150-0104 EXPIRES: 06/30/2007
LICENSEE EVENT REPORT (LER) (See reverse for required number of digits/characters for each block)		Estimated burden per response to comply with this mandatory collection request: 50 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.

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4. TITLE
Loss of Safety Function of High Pressure Core Spray Due to Manual Deactivation

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
01	24	2006	2006	- 002 -	00	03	27	2006	FACILITY NAME	DOCKET NUMBER 05000

9. OPERATING MODE: 1

10. POWER LEVEL: 100

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)
David N. Lorfing, Manager – Licensing	225-381-4157

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
NA									

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

ABSTRACT *(Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines)*

On January 24, 2006, at 7:32 p.m. CST, the high pressure core spray (HPCS) system was inadvertently initiated during surveillance testing. The plant was operating at 100 percent power at the time. The HPCS injection valve was open for approximately 40 seconds before the operators manually closed the valve. The Division 3 diesel generator (DG) also automatically started in response to the actuation signal. The DG did not automatically connect to the Division 3 switchgear since there was not a low voltage condition on that bus. The manual closure of the injection isolation valve caused the system to be incapable of responding to an automatic actuation signal. The manual override of the injection isolation valve was reset approximately 97 minutes after the event, restoring the system to its standby condition. This event was caused by lack of procedural guidance concerning test leads needed for the surveillance. The affected procedures were subsequently revised and successfully completed. This event is being reported in accordance with 10CFR5073(a)(2)(iv) as an invalid actuation of the HPCS system, and with 10CFR50.73(b)(3)(v)(d) as a condition that caused the loss of function of the HPCS system. This event is also reportable pursuant to River Bend Station Technical Requirements Manual Section 5.6.9.2., "ECCS Systems Actuations."

REPORTED CONDITION

On January 24, 2006, at 7:32 p.m. CST, the high pressure core spray (HPCS) (BG) system was inadvertently initiated during surveillance testing. The plant was operating at 100 percent power at the time. The HPCS injection valve (**INV**) was open for approximately 40 seconds before the operators promptly implemented the appropriate response procedures and manually closed the valve. The operators shut down the HPCS pump approximately three minutes after the initiation. The Division 3 diesel generator (DG) (**DG**) also automatically started in response to the actuation signal. The DG did not automatically connect to the Division 3 switchgear since there was not a low voltage condition on that bus. This event is being reported in accordance with 10CFR5073(a)(2)(iv) as an invalid actuation of the HPCS system, and with 10CFR50.73(b)(3)(v)(d) as a condition that caused the loss of function of the HPCS system. HPCS is a single-train safety system. The manual closure of the injection isolation valve caused the system to be incapable of responding to an automatic actuation signal. The manual override of the injection isolation valve was reset approximately 97 minutes after the event, restoring the system to its standby condition.

This event is also reportable pursuant to River Bend Station Technical Requirements Manual Section 5.6.9.2 regarding ECCS system actuations. This event was the thirteenth HPCS injection since initial plant startup in October 1985.

INVESTIGATION

At the time of the event, Instrumentation & Controls (I&C) technicians were performing a scheduled surveillance test procedure (STP) to calibrate instruments in the HPCS initiation circuitry. Other than the conditions required for this test, the HPCS system was in its normal standby configuration. This was one of four companion STPs scheduled during the nights of January 23rd and 24th that test redundant channels in the system. These tests involve checking for trip circuit continuity through a multi-pin test jack on the panel containing the trip units. One pair of STPs checks the B-to-C pins (performed on January 23rd) and the other STPs set checks the A-to-B pins (scheduled for January 24th).

River Bend had previously evaluated a similar event that occurred at another plant in 2003. Prior industry operating experience had identified that this type of test (checking inside the multi-pin jack itself) is risky due to the possibility of making contact with the wrong connections. River Bend evaluated different types of test fixtures and determined that since just two pins are needed for each pair of tests, an enhanced "break-out" test lead exposing only two pins at a time would involve less risk of error. One break-out lead was built for testing the B-to-C pins, and another was built for the A-to-B pins.

STPs were successfully performed the night prior to the event using the B-to-C break-out lead. The test being conducted at the time of the event required the use of the A-to-B break-out lead. The B-to-C break-out lead was used instead. The STPs do not specifically identify the break-out lead to be used, but identify the need to check continuity across certain pins. The break-out leads are labeled as to which pins they make available for continuity check. Other than the information on the label itself, the leads look alike (i.e., color and length). Starting the test with the incorrect break-out lead installed trips half the logic circuitry required for a system actuation. A trip of the rest of the circuit, as done during the test, completed the actuation signal leading to the actuation of the Division 3 DG and HPCS system. The operators responded using the appropriate response procedures, and closed the HPCS injection valve. The remaining tests were postponed pending an investigation.

Immediate corrective actions were taken to positively identify the two break-out leads, and to revise the STPs. Briefings on the event were conducted for the I&C technicians. The remaining tests were successfully performed the following night.

Plant equipment and systems responded appropriately to the initiation signal. The HPCS injection caused reactor vessel water level to increase from 36 to 45 inches of water. Reactor feedwater controls responded to compensate for the injection flow. Reactor power, as indicated on the average power range monitors, did not change during the injection. The Division 3 DG was loaded as required by procedure. The DG was returned to its standby condition at 11:56 p.m.

CAUSAL ANALYSIS

The STP being conducted at the time of the event required the technicians to take continuity measurements between pins A and B on the multi-pin test jack. The procedure did not specify which break-out lead to use. The technicians did not recognize the uniqueness of one break-out lead and the other.

In addition, the RBS procedure writers' guide did not clearly address human factors defenses.

Although the operating experience from the 2003 event was used and corrective actions implemented to prevent the event from occurring at RBS, it still occurred. A review of the corrective actions initiated in response to the 2003 event found that the decision was made that no procedure revisions were needed. Critical thinking of Maintenance personnel did not lead to consideration of what would happen if the tools (i.e., break-out leads) were improperly used.

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CORRECTIVE ACTIONS TO PREVENT RECURRENCE

The break-out leads involved in this event have been color coded and re-labeled for positive identification. The affected procedures have been revised to provide specific identification of the required break-out leads.

A review of the STPs was conducted after this event, and it found that thirteen other procedures involve the use of similar test leads. This review determined that none of these STPs specifically identify the test leads, nor do they contain steps to verify the correct test lead is being used. Actions have been initiated to correct this procedure deficiency, and will be tracked in the RBS corrective action program. As previously described, a human performance stand-down and briefing on this event were conducted for the I&C maintenance staff.

Actions have been initiated to revise the RBS procedure writers' guide, as well as to enhance critical thinking and human factor defense management. These actions will be tracked in the RBS corrective action program.

PREVIOUS OCCURRENCE EVALUATION

A similar HPCS initiation at another boiling water reactor in September 2003 had been evaluated at RBS as operating experience. As described above, that review did not result in the procedure revisions that could have prevented this event.

SAFETY ANALYSIS

The RBS Updated Safety Analysis Report addresses an inadvertent initiation of HPCS. Analyzed reactor pressure and temperature variations are relatively small and no significant consequences are expected. The minimum critical power ratio remains above the safety limit and, therefore, fuel thermal margins are maintained.

Plant equipment responded appropriately to this event. There was no observable change in reactor power, as measured by the average power range monitors. Calculated thermal power, as measured by the plant process computer heat balance, decreased because feedwater mass flow rate is the primary measured variable of the plant heat balance calculation. The HPCS injection was replacing part of this flow, but it is not included in the heat balance calculation.

The main feedwater control system reduced feedwater flow rates in response to the HPCS injection, minimizing the reactor water level transient.

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While the manual "close" signal was present on the HPCS injection valve, that valve would not automatically re-open in response to any subsequent system initiation. In that circumstance, the HPCS pump would have automatically started and operated on the minimum flow path. Had the safety function of the system been necessary, the injection valve could have been manually re-opened. During the 97 minutes that the injection valve was overridden closed, there was no condition requiring an actual operation of the system.

This event was of minimal significance to the health and safety of the public.

(NOTE: Energy Industry Component Identification codes are annotated as (**XX**).)