NRC FORM 366 (4-95) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)

APPROVED BY OMB NO. 3150-0104
EXPIRES 04/30/98

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS MANDATORY INFORMATION COLLECTION REQUEST: 50.0 HRS. REPORTED LESSONS LEARNED ARE INCORPORATED INTO THE LICENSING PROCESS AND FED BACK TO INDUSTRY. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (T-6 F33), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
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Reactor Scram Results From MSIV Closure Caused By A Spurious Group 1 Isolation Signal Due To Inadequate Preventative Maintenance

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	N/A
									FACILITY NAME	DOCKET NUMBER
04	09	98	98	003	00	05	11	98	N/A	N/A

OPERATING MODE (9)	1	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR § (Check one or more) (11)									
POWER LEVEL (10)	099		20.2201(b)		20.2203(a)(2)(v)		50.73(a)(2)(i)		50.73(a)(2)(viii)		
			20.2203(a)(2)(i)		20.2203(a)(3)(i)		50.73(a)(2)(ii)		50.73(a)(2)(x)		
			20.405(a)(1)(ii)		20.2203(a)(3)(ii)		50.73(a)(2)(iii)		73.71		
			20.2203(a)(2)(ii)		20.2203(a)(4)	X	50.73(a)(2)(iv)		OTHER		
			20.2203(a)(2)(iii)		50.36(c)(1)		50.73(a)(2)(v)		Specify in Abstract below or in NRC Form 366A		
			20.2203(a)(2)(iv)		50.36(c)(2)		50.73(a)(2)(vii)				

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
D. Spencer, Plant Engineering	(815) 942-2920 ext 3292

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
X	JM	PDIS	I204	Y						

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

ABSTRACT (Limit to 1400 spaces, i. e., approximately 15 single-spaced typewritten lines) (16)

At approximately 0040 on 4/9/98, while the A Primary Containment Isolation System (PCIS) channel was in the tripped condition, a spurious Group 1 isolation on the B channel of PCIS caused the Main Steam Isolation Valves (MSIVs) to close. At less than 90 percent MSIV full open, a Reactor scram signal was appropriately received. Subsequent to the Reactor Scram, a valid Group 1, Containment Isolation occurred on Low Main Steam Line pressure. Additionally, a Group 2 and 3 containment isolation occurred on the level shrink after rod insertion. Reactor vessel level was recovered using the Feedwater system. Feedwater was secured with vessel level at approximately at 35 inches above instrument zero. The Isolation Condenser was placed in service to control reactor pressure. With the MSIVs closed and reactor pressure greater than 600 psig, the scram signal could not be reset. The inability to reset the scram resulted in the control rod drive system injecting water into the reactor vessel which caused an increase in reactor vessel water level. Prior to establishing reactor water blowdown using the reactor water cleanup system vessel level increased to approximately 60 inches. Approximately 20 minutes into the event, a High Pressure Coolant Injection (HPCI) inlet drain pot high level alarm was received which indicated that water had entered the HPCI steam supply piping. Operations personnel manually isolated the HPCI system by closing a steam supply isolation valve. The root cause of the spurious B channel, PCIS group 1 half isolation signal was dirty, oxidized contacts on a relay in the Main Steam Line Low Pressure sensing logic concurrent with a previously existing PCIS A channel half isolation signal. The relay contacts which resulted in the spurious signal were cleaned. Other similar relays in Main Steam Line Low Pressure sensing logic were inspected to ensure similar conditions did not exist. The safety significance of this event was minimal. All safety systems operated as designed. During the time HPCI was isolated, all other ECCS systems were available to mitigate the consequences of an accident.

PLANT AND SYSTEM IDENTIFICATION:

General Electric - Boiling Water Reactor - 2527 MWt rated core thermal power

Energy Industry Identification System (EIIS) Codes are identified in the text as [XX] and are obtained from IEEE Standard 805-1984, IEEE Recommended Practice for System Identification in Nuclear Power Plants and Related Facilities.

EVENT IDENTIFICATION:

Reactor Scram Results From MSIV Closure Caused By A Spurious Group 1 Isolation Signal Due To Inadequate Preventative Maintenance.

A. PLANT CONDITIONS PRIOR TO EVENT:

Unit: 3 Event Date: 4/9/98 Event Time: 0040 CDT
Reactor Mode: 1 Mode Name: Run Power Level: 099 %
Reactor Coolant System Pressure: 1000 psig

On 4/8/98, Instrument Maintenance personnel performed scheduled surveillance DIS 0250-01, "Main Steam Line High Flow Isolation Switch Calibration". During the course of this calibration, Differential Pressure Indicating Switch (DPIS) 3-261-2E was found to exhibit excessive binding in the meter movement and switch operation. As a result, the switch was declared inoperable. At approximately 1543, the A Channel of Group 1 Primary Containment Isolation system (PCIS)[JM] logic was placed in the tripped condition in accordance with Technical Specification 3.2.A.2 action requirements. Preparations were being made to replace DPIS 3-261-2E.

B. DESCRIPTION OF EVENT:

This LER is being submitted pursuant to 10 CFR 50.73(a)(2)(iv), which requires the reporting of any event or condition that results in manual or automatic actuation of any Engineered Safety Feature (ESF), including the Reactor Protection System (RPS)[JC].

At approximately 0040 on 4/9/98, while the A PCIS channel was in the tripped condition, a spurious Group 1 isolation signal on the B channel of PCIS caused the Main Steam Isolation Valves (MSIVs)[SB] to close. At less than 90 percent MSIV full open, a reactor scram signal was appropriately received. The following data was recorded during the transient:

- 0.4 seconds after the MSIVs received a spurious and short duration isolation signal, a reactor scram signal was received caused by the MSIVs being less than 90 percent full open.
- 2.2 seconds into the event, a Main Steam Line (MSL) Pressure less than 850 psi signal was received. Since the Mode Switch was in the RUN position, a Group 1 isolation signal was generated in accordance with plant design.
- 2.5 seconds into the event, the Isolation Condenser [BL] 1301-20 valve indicated full closed in response to the spurious Group 1 isolation signal.
- 3.2 seconds into the event, the Isolation Condenser 1301-17 valve indicates full closed in response to the spurious Group 1 isolation signal.
- 3.9 seconds into the event, all Inboard and Outboard MSIVs indicate full closed.

- 4.2 seconds into the event, a manual reactor scram was initiated.

- 5.6 seconds into the event, the Mode Switch was placed in Shutdown.
- Approximately one minute and six seconds into the event, the main turbine/generator [TA/TB] tripped on reverse power as expected.

Investigation indicated the following regarding plant response to the transient:

- All eight (8) MSIVs closed in the appropriate time frame (approximately 4.0 seconds).
- Reactor Scram signal was received when MSIVs were at 90 percent open (approximately 0.4 seconds which is about 10 percent the travel time).
- All other valves in the Group 1 isolation logic closed in an appropriate time frame.
- Groups 2 and 3 Containment Isolations were received on low reactor water subsequent to the scram as expected.

Due to previous scrams, from high power, contingencies had been implemented which directed Operations personnel to monitor feedwater performance during these incidents and control reactor level manually to prevent over-filling the vessel, if necessary. Following the scram and the initial level shrink, operations personnel took manual control of the feedwater level control system (FWLC)[JB]. The feedwater regulating valves were manually closed, thereby securing feedwater [SJ] flow to the reactor vessel. Reactor water level was at approximately 35 inches above instrument zero (Instrument Zero is 144 inches above the Top of Active Fuel). Even though the operator's actions regarding FWLC met management expectation of preventing feedwater injection prior to reaching 48 inches, areas for improvement were identified as a result of this event.

The Isolation Condenser was placed in service to control reactor pressure. With the MSIVs closed and reactor pressure greater than 600 psig, the scram signal could not be reset. The inability to reset the scram resulted in the control rod drive system (CRD) [AA] injecting approximately 200 gpm of water into the reactor vessel through the CRD mechanisms which caused an increase in reactor vessel water level. Subsequently, vessel level increased to approximately 60 inches above instrument zero. This increase in level is attributed to the typical swell that is associated with placing the Isolation Condenser in service and the added inventory of CRD charging water flow. Subsequently, a "HPCI TURB INLET DRN POT LVL HI" alarm was received which indicated that water had entered the High Pressure Coolant Injection (HPCI)[BJ] steam supply piping. Operations personnel manually isolated the HPCI system by closing a HPCI steam supply isolation valve and declared HPCI inoperable in accordance with conservative operating philosophy. Following the isolation of the HPCI system, the appropriate TS action statement was entered. The HPCI steam supply line was allowed to drain and the system was returned to normal alignment within approximately 20 minutes.

Reactor water blowdown through the reactor water cleanup system (RWCU)[CE] was established and vessel level was stabilized at approximately 30 inches above instrument zero.

C. CAUSE OF EVENT:

The cause of the reactor scram has been determined to be closure of the MSIVs in response to a spurious Group 1 PCIS signal. A trip signal was provided to the RPS logic when the MSIVs were less than 90 percent open as designed. Evidence to support this is the first out alarm of MSIVs NOT FULL OPEN and Sequence Of Events Recorder times.

The Group 1 isolation was caused by a spurious half Group 1 signal on the B PCIS channel concurrent with a pre-existing half Group 1 signal on the A PCIS channel. The cause of the spurious half Group 1 isolation signal on the B PCIS channel was due to a momentary loss of the control signal to the 595-103D-1 relay in the de-energize to trip PCIS logic. This relay is part of the Group 1 isolation logic on low Main Steam Line pressure. The 595-103D-1 relay causes de-energization of other relays in the PCIS logic after a nominal 0.25 second time delay which closes Group 1 Containment Isolation Valves.

The cause of the momentary loss of the control signal to the 595-103D-1 relay was found to be dirty and oxidized contacts on the 595-103D relay. The 595-103D relay is a General Electric model HFA. This relay receives its signal directly from the instrument which senses MSL pressure. Analysis of the event indicated that the momentary loss of MSL low pressure control signal was of insufficient duration to allow control room annunciation.

During testing, the 595-103D relay was found to exhibit high and inconsistent contact resistance. The investigation determined that although HFA relay contacts are self-cleaning during normal operation in a 115 volt circuit, enhanced PM is required when using the HFA in a low current or low voltage application. The MSL low pressure sensing logic senses the HFA contact position in a low voltage, low current loop. Slow increase in contact resistance caused by a buildup of oxidation, caused the time delay relay to trip which, in turn, resulted in a trip of the B logic channel causing the Group 1 isolation

This momentary loss of power to the B channel of PCIS group 1 logic coincident with the A channel which had been previously placed in the tripped condition resulted in a full Group 1 PCIS signal which, in turn resulted in all Group 1 containment isolation valves closing. As the MSIVs closed, MSL pressure decreased to the point where a sustained MSL low pressure signal was generated as the MSIVs interrupted steam flow to the Main Turbine [TA]. At this point the Group 1 PCIS logic sealed in on Low MSL Pressure.

The Agastat 595-103D-1 time delay relay was installed in 1991 (Modification M12-3-91-20) to prevent spurious Group 1 isolations resulting from pressure oscillations following closure of the main turbine stop valves. The HFA preventative maintenance inspection procedure, DES 0500-02, "HFA Relay Electrical Maintenance Inspection", performs a visual inspection of the relays. No contact cleaning is performed by this procedure. DEP 0500-03, "HFA Relay Adjustment and Coil Assembly Replacement", addresses contact cleaning and wipe adjustment. DEP 0500-03 is performed based on the results of the visual inspection. Maintenance history does not identify that contact cleaning had been performed on the 3-595-103D HFA relay.

The initiating condition for the trip was high contact resistance in the sensing logic for B channel of PCIS logic concurrent with a half isolation signal being present on the A PCIS channel. The root cause for the high contact resistance was lack of an effective PM program to evaluate contact condition and perform any necessary contact cleaning for HFA relays in low current, low voltage applications (NRC Cause Code E). Contributing to this event was the condition in which the A PCIS channel was in the tripped condition for an extended period of time to support replacement of a Main Steam High Flow Switch which exhibited unsatisfactory performance approximately 10 hours earlier.

Group 2 and 3 Containment Isolations occurred as a result of the Reactor Water level shrinkage caused by the scram.

The cause of water entering the HPCI is due to not having timely procedural guidance to promptly inhibit CRD input and establish RWCU system blowdown during a Group 1 isolation.

D. SAFETY ANALYSIS

A review of plant parameters (high radiation, high steam line flow, low pressure with mode switch in run, low reactor water level, high steam tunnel temperature) indicated that no valid Group 1 isolation signals were present which would have initiated this event. All safety systems operated as designed when challenged by the spurious signal.

During the time that the HPCI system was out of normal lineup, all other ECCS systems were available to mitigate the consequences of an accident. The HPCI system was restored to normal alignment in approximately 20 minutes. If a HPCI system initiation signal had occurred during the time that the steam supply valve was closed, it could have been re-opened for HPCI injection, if necessary. HPCI was declared inoperable during this time in accordance with conservative operating philosophy. During this event, the Isolation Condenser was operated. Due to small amounts of residual contamination in the shell-side of the Isolation Condenser, isotopic analyses were performed. Based on the analyses, the estimated offsite dose consequence which would have been associated with the operation of the Isolation Condenser during this period was less than 0.1 percent of the 7.5 mrem quarterly organ dose objective. The plant was operated within design limits. The health and safety of the public were not compromised as a result of this event. Therefore, safety significance is minimal.

E. CORRECTIVE ACTIONS:

1. DPIS 3-261-2E which performed unsatisfactorily prior to the transient has been replaced. (Complete)

2. DIS 250- 01, "Main Steam Line High Flow Isolation Switch Calibration", was completed on all other Main Steam Line High Flow Switches in Unit 3 prior to restart. (Completed).

3. All RPS and PCIS relays on the control room 903-15 and 17 panels as well as the Auxiliary Equipment Room were walked down prior to resetting the isolation and scram signal. All relays were found to have proper indication for the plant conditions. No evidence of malfunction was noted.(Completed)

4. A walkdown of piping and instruments related to Main Steam Line High Flow and Low Pressure was performed. No abnormalities were discovered. (Completed)

5. The contacts on the 3-595-103D HFA relay, have been cleaned and verified to exhibit repeatable low resistance values. (Complete)

6. All other 595-103 relays were inspected, tested and verified not to exhibit high or inconsistent contact resistance in both Units 2 and 3. (Completed)

7. A review of other similar applications of an HFA relay contacts providing input to similar Agastat timer applications has been performed. This review has indicated that the Main Steam High Flow Sensing logic on Units 2 and 3 are the only similar applications at Dresden Station. (Completed)

8. Plant transient data indicated that although Reactor Water level during the transient exceeded the bottom of the HPCI Steam Line, the quantity of water is believed to be small. The operator action of isolating HPCI in response to this small and gradual water intrusion was proper. A walkdown of HPCI piping indicated that this water intrusion was not detrimental to the HPCI system (Completed).

9. Enhanced training has been developed to address lessons learned on manual FWLC during this event. All Nuclear Station Operators are required to practice Feedwater Level Control response to a full scram with a Group 1 Isolation prior to assuming duties on Unit 3. Action in place. (Complete).

10. An operator aid has been developed to expedite placing reactor water blowdown in service. (Complete)

11. Scram Procedure DGP 02-03 has been revised to allow CRD charging water to be isolated to augment reactor water level control when appropriate. (Complete)

12. Investigation indicated that the performance of the Main Steam Line High Flow Switches on both Units 2 and 3 have exhibited an adverse trend in recent months. A more detailed review of switch performance and identification of potential replacements has been initiated. (NTS 249-180-98-00301)

13. A review of other HFA relay contacts in low current, low voltage applications is being performed to determine if other plant applications are susceptible to a similar event. (NTS 249-180-98-00302)

14. A review of work practices in place at the time that the 3-261-2E High Steam Line Flow Switch failed was performed to determine if additional measures could be implemented to expedite switch replacement. A procedure is being developed which will allow switch repair/replacement under a minimal work request. Minimum and maximum replacement parts have been identified to ensure parts are on hand to provide for expeditious switch replacement. The new procedure will be in place prior to the next scheduled DIS 0250-01, Main Steam Line High Flow Isolation Switch Calibration, performance. (NTS 249-180-98-00303)

15. FWLC system for Unit 2 has been modified and the operator contingencies have been terminated. (Complete)

16. The operator contingencies for the Unit 3 FWLC will be terminated upon completion of the FWLC modification. (NTS 249-180-98-00304)

17. A preventative maintenance activity will be established for periodic cleaning of existing and future relay contacts for HFA relays in low voltage applications. (NTS 249-180-98-00305)

F. PREVIOUS OCCURRENCES:

No previous events were identified that were attributed to spurious group 1 isolations due to the root cause identified.

Similar occurrences related to feedwater in HPCI steam supply system include

LER/Docket	Title
95-008/05000249	On May 28, 1995, Unit 3 scrammed from Main Turbine Stop Valve Closure due to Turbine Trip On High Vibration. Subsequent to the scram, a feedwater transient occurred which resulted in water entering into the HPCI steam supply line. The feedwater transient was caused by a design deficiency in the FWLC logic. Modifications to the FWLC system logic were implemented. These actions would not have prevented this event.
97-019/05000237	On December 23, 1997, Unit 2 scrammed as a result of a spurious LPRM spike coincident with existing half trip condition on the redundant RPS trip system. Following the scram, a feedwater transient occurred which resulted water entering the HPCI steam supply line. The cause of the feedwater transient was due to a design deficiency in the FWLC logic. Further modification of the FWLC system was planned. Additionally, contingencies were put in place to provide instructions for control vessel level following scrams from high power. These actions would not have prevented this event.

G. COMPONENT FAILURE DATA:

Manufacturer	Nomenclature	Model Number
ITT-Barton Instrument	Differential Pressure Indicating Switch	278