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Date: September 4, 2001

U.S. Nuclear Regulatory Commission
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Washington, D.C. 20555

Subject: McGuire Nuclear Station, Unit 2
Docket Nos. 50-370
Licensee Event Report 370/01-01, Revision 0
Problem Investigation Process No.: M-01-3139

Gentlemen:

Pursuant to 10 CFR 50.73 Sections (a)(1) and (d), attached is Licensee Event Report 370/01-01, Revision 0, concerning a McGuire Unit 2 event that resulted in an automatic closure of the Main Steam Line Isolation valves, actuation of the Reactor Protection System, and actuation of the Auxiliary Feedwater System. This event was initially reported on July 16, 2001 per the requirements of 10 CFR 50.72(b)(2)(ii).

On July 16, 2001, McGuire Unit 2 experienced a reactor trip (RPS actuation) as a result of an Overtemperature Delta Temperature (OTDT) condition. This OTDT condition was caused by the closure of all Unit 2 Main Steam Isolation valves. The Main Steam Isolation was caused by personnel error. The Unit 2 Auxiliary Feedwater Pumps started as a result of the Reactor Trip.

This report is being submitted in accordance with 10 CFR 50.73 (a)(2)(iv). This event is considered to be of no significance with respect to the health and safety of the public. This event report does not contain any regulatory commitments.

Very truly yours,

HB Barron

H. B. Barron, Jr.

Attachment

IE22

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NRC FORM 366 (1-2001) U.S. NUCLEAR REGULATORY COMMISSION	
LICENSEE EVENT REPORT (LER)	Estimated burden per response to comply with this mandatory information 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 Management Branch (T-6 E6), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, or by internet e-mail to bjs1@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 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.

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
McGuire Nuclear Station, Unit 2	05000 370	1 OF 6

TITLE (4) Unit 2 Reactor Trip and Auxiliary Feedwater System Actuation

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MO	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REV NO	MO	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
07	16	01	01	– 01 –	0	09	04	01	FACILITY NAME	DOCKET NUMBER

OPERATING MODE (9)	1
POWER LEVEL (10)	100

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

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

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
C. J. Thomas, Regulatory Compliance Manager	(704) 875-4535

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

CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX

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)

Unit Status: On 7/16/01, Unit 1 and Unit 2 were in Mode 1 (Power Operation) at 100 percent power.

Event Description: On 7/16/2001, Maintenance personnel were performing routine maintenance on pressure instrumentation associated with the Unit 2 Main Steam Lines. Maintenance personnel in the Control Room area placed Channel 2 of 2B steam line pressure in test in the 7300 process protection cabinets as required per the test procedure. Maintenance personnel in the field then incorrectly isolated Channel 3 steam line pressure transmitter. This satisfied the 2 of 3 protection logic initiating a Main Steam Isolation Signal. Closing the Main Steam Isolation Valves resulted in a Reactor Trip and a Main Turbine Trip. An automatic start of the three Auxiliary Feedwater Pumps (CA) occurred as a result of decreasing Steam Generator levels.

Event Cause: Lack of attention to detail has been determined to be the cause of the wrong pressure transmitter being isolated.

Corrective Action: The Maintenance personnel were counseled on the importance of maintaining a high level of attention to detail. Component verification process enhancements were implemented.

EVALUATION:

BACKGROUND:

The Overtemperature Delta Temperature (OTDT) trip is one of nineteen Reactor [EIIS:RCT] trip inputs associated with the Reactor Protection (IPE) system [EIIS:JC]. It protects the core against Departure from Nucleate Boiling (DNB) and causes the Reactor to trip when 2 out of 4 channels [EIIS:CHA] exceed the setpoint. The OTDT trip setpoint is variable depending on the average Reactor coolant temperature (T-ave), Pressurizer [EIIS:PZR] pressure, and axial flux difference (AFD). The setpoint provides protection against DNB over a range of temperatures and pressures. The OTDT trip setpoint is continuously calculated by solving an equation given in Technical Specification (TS) Table 3.3.1-1, Reactor Trip System Instrumentation.

Main Steam (SM) [EIIS:SB] isolation valves (MSIV) [EIIS:ISV] are provided in each Steam Generator (SG) [EIIS:SG] steam line immediately downstream of the code safety valves [EIIS:RV] to isolate each individual SG in the event of a steam line rupture. The MSIVs close on high-high Containment pressure and/or high steam line pressure rate of change or low steam line pressure as the result of a SM line rupture between the SG and the Turbine [EIIS:TRB] steam stop valves [EIIS:V]. The McGuire Nuclear Station design does not include a Safety Injection on low steam line pressure. Three pressure instruments, each representing one instrument channel, monitor each of the main steam lines with inputs to the 7300 Protection Cabinets for generation of this Main Steam Isolation function. The Main Steam Isolation signal closes the MSIVs, the MSIV Bypass valves, and blocks opening of the steam line Power Operated Relief Valves (PORVs). A 2 out of 3 logic is utilized for these steam line pressure inputs for the Main Steam Isolation.

The Auxiliary Feedwater (CA) system [EIIS:BA] provides feedwater in the event of a loss of normal Main Feedwater [EIIS:SJ]. The CA system can also be used in normal plant startup and shutdown as main feedwater, when required flow is less than 3 percent maximum designed feedwater flow. The CA system is not required to function during normal plant operation. It is normally aligned in standby readiness to respond to events involving the loss of main feedwater. The CA system provides feedwater to all four SGs. Its primary safety function is the removal of decay and residual heat from the reactor coolant system.

The CA system contains 2 motor [EIIS:MO] driven pumps [EIIS:P], 1 turbine [EIIS:TRB] driven (TD) pump and associated piping, valves [EIIS:V] and controls. The TD pump is capable of supplying feedwater to all four SGs. The McGuire Updated Final Safety Analysis Report (UFSAR) and facility TS's identify the CA system as one of the Engineered Safety Features (ESFs).

The TDCA pump is powered by a turbine independent of the main electrical generator and main feedwater pump turbines. The steam supply to this turbine flows through two redundant steam lines. These steam lines branch from main steam lines 2B and 2C prior to the MSIVs. This design ensures that the steam supply is not interrupted in the event of a main steam isolation. Each steam supply line to the TDCA Pump includes a control valve that opens on a TDCA pump start signal. The valves are piston operated and designated as 2SA48 from the 2C steam line and 2SA49 from the 2B steam line.

Event Description:

At the time of the event on July 16, 2001, Unit 2 was in Mode 1 at 100% power. Instrument and Electrical (IAE) personnel were assigned to perform preventative maintenance procedure IP/2/A/3001/002E (Main Steam Line Pressure Calibration Loop B, Channel 2, 2SMLP5120). At approximately 0800, one of the IAE Technicians conducted a pre-job briefing with the crew stressing independent verification of the components.

At approximately 0940, IAE Technicians A and B went to the 2B Main Steam Line Channel 2 pressure transmitter and IAE Technicians C and D went to the Control Room 7300 Process Protection Cabinets. Technicians A and B performed proper verification of the Channel 2 transmitter by comparing the component label on the transmitter with the work order (W.O. 98366206) and procedure to be performed. Technicians A and B then placed their test equipment approximately 2 feet away from the Channel 2 transmitter to allow working room. It was later determined that the test equipment was placed next to the Channel 3 transmitter.

At approximately 0956, Technicians C and D received permission from the Operations Control Room Supervisor and placed 2B Main Steam Line pressure Channel 2 in test at the 7300 Process Protection Cabinets. The test position places the Channel 2 in the trip condition and satisfies one channel of the two of three logic for protection circuits. Technicians C and D informed Technicians A and B that they were ready for them to perform the procedure steps to isolate the Channel 2 steam line pressure transmitter.

At approximately 0957, Technician A proceeded to the transmitter located next to the test equipment. Technician A then traced the tubing to the isolation valve for the Channel 3 transmitter. Technician A requested Technician B to verify that was the correct valve. Technician B stated that it was the correct valve. Technician A closed the isolation valve for the Channel 3 transmitter and opened the test tee cap. This vented the pressure from the Channel 3 transmitter which signaled the 7300 Process Protection Cabinets of a lo-lo steam line pressure condition. Since Channel 2 was in test, this signal satisfied the two of three logic for a lo-lo steam line pressure and initiated a Main Steam Line Isolation.

Technician A realized his mistake and immediately called the Control Room Operator to inform him of the error.

The Main Steam Isolation Signal closed the MSIVs and blocked opening of the SM PORVs. The steam line code safety relief valves opened as designed to maintain steam line pressure. Reactor coolant pressure increased to the lift setpoint for the Pressurizer PORVs. As pressure decreased, the OTDT setpoint decreased to the actual Reactor coolant temperature and an OTDT Reactor Trip occurred at 0958:40. Two of the three Pressurizer PORVs closed after 4 seconds and the third PORV closed after 8 seconds. This time difference is due to the design of the control circuits for these PORVs.

After the Reactor trip, the Main Feedwater pumps went to Rollback Hold as designed. The 2A and 2B CA pumps started at 1001:19 upon receipt of a 2C SG LoLo level signal. The TDCA pump started at 1004:06 when the 2D SG level reached the lo-lo level setpoint. Valve 2SA48 (Main Steam From SG 2C To TDCA Pump Isolation) opened as designed to provide steam to the TDCA pump. However, the redundant steam supply valve 2SA49 (Main Steam From SG 2B To TDCA Pump Isolation) did not open until 1006:55. The TDCA pump remained capable of performing its Safety Function (2SA48 opened to supply steam to the TDCA pump).

Valves 2SV2 and 2SV21, Steam Line Safety Valves, failed to fully reseat initially after opening to maintain steam line pressure. These valves did fully reseat following a small reduction in steam line pressure.

CAUSE:

The cause of the Unit 2 Main Steam Isolation, Reactor trip, and the resultant CA System actuation has been determined to be inappropriate action due to lack of attention to detail. The IAE Technicians at the transmitter performed proper component verification on the Channel 2 transmitter when they first arrived at the work site. The Technicians then performed other tasks and failed to reverify the correct component prior to isolating the transmitter as directed by their procedure. The 2B Main Steam Line Channel 3 transmitter was isolated in place of the Channel 2 transmitter.

The delay in opening valve 2SA49 was subsequently determined to be due to a higher than expected valve factor. 2SA49 was verified to have satisfactorily passed its last quarterly stroke testing on 5/17/01. This stroke test is an ASME Section XI In-service test required by the McGuire TSs. It is performed at normal steam line pressure. Note that following the Main Steam Isolation, steam pressures were elevated due to the MSIVs being closed. This, in combination with the higher than expected valve factor, contributed to the slow opening time for 2SA49. Prior to restarting the unit, a modification was performed on this valve which installed a booster spring to assist in opening the valve from its closed seat. The redundant valve, 2SA48, and the Unit 1 valves, 1SA48 and 1SA49, also had booster springs installed to increase the available thrust margin for opening.

The delay in valves 2SV2 and 2SV21 reseating was determined to be caused by the temperature increase in the body, bonnet, and superstructure of the valves while open. The net effect of this heating tends to reduce the reseat pressure and is a known industry phenomenon. Valves 2SV2 and 2SV21 both reseated at a pressure 12% below their nominal lift setpoint. The reseat pressure for each of these valves is normally set for 7% below their nominal lift setpoint. This change in reseat value is not uncommon and is within the bounds of the Safety Analysis.

CORRECTIVE ACTIONS

Immediate:

1. Operations personnel entered procedure EP/2/A/5000/E-0 Reactor Trip or Safety Injection.

Subsequent:

1. Engineering personnel evaluated the cause for 2SA49 not opening as expected. A modification was performed to install a booster spring to assist in opening the valve. Post modification testing verified the proper operation of this valve.
2. Modifications were performed on valves 2SA48, 1SA48, and 1SA49 to install booster springs to assist in opening the valves. Post modification testing verified the proper operation of these valves.
3. Engineering personnel evaluated the performance of valves 2SV2 and 2SV21.
4. Individuals involved were counseled on the requirements for component verification.

5. A Site 'Time Out' was conducted to re-emphasize the importance of, and the proper method for, component verification.
6. Component verification process enhancements were implemented.

Planned:

1. Engineering personnel will evaluate the cause of the higher than normal valve factor for 2SA49 and initiate appropriate corrective actions.

SAFETY ANALYSIS

This event did not include a Safety System Functional Failure.

The conditional core damage probability (CCDP) of this event has been evaluated by considering the following:

- A loss of load (turbine trip) initiating event
- Actual plant configuration at the time of the trip
- All Pressurizer PORVs lifted
- Valve 2SA49 failed to open

The CCDP for this type of event is dominated by sequences involving stuck open Pressurizer PORVs with failure of high pressure recirculation from the containment sump.

Duke Power plans to evaluate transients that have the potential to lift the primary PORVs to identify enhancements that could lessen the likelihood of lifting these relief valves.

Two (2) steam line safety valves failed to fully reseat initially. They did fully reseat following a small reduction in steam line pressure. This is expected behavior for these valves.

There were no releases of radioactive materials, radiation exposures or personnel injuries associated with this event. There was no impact on the health and safety of the public or plant personnel due to this event.