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INTERIM REPORT

TECHNICAL EVALUATION REPORT
ELECTRIC, INSTRUMENT, AND CONTROL ASPECTS OF INADVERTENT SAFETY INJECTIONS AT SALEM, UNIT 1

DOCKET 50-272

by

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ELECTRIC, INSTRUMENT, AND CONTROL ASPECTS
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SALEM, UNIT 1

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1.0 INTRODUCTION

Since November 30, 1976, the Public Service Electric and Gas Company's (PSE&G) Salem Unit No. 1 Nuclear Station, a Westinghouse four (4) loop PWR, has experienced eleven (11) inadvertent safety injections (SIs).

A Westinghouse letter dated December 13, 1976, to PSE&G states that the SI nozzles can withstand fifty (50) SIs with a 40°F water transient before the appropriate stress limits of the nozzles are exceeded.

The objectives of this report are to:

(1) Review the electrical, instrument, and controls (EI&C) of the safety injection systems to determine if changes will be required to prevent future inadvertent safety injections

(2) Determine if any generic problems exist in other PWRs concerning inadvertent SIs.

2.0 DESCRIPTION AND EVALUATION OF SAFETY INJECTIONS

All of the docketed Licensee Event Reports and Emergency Core Cooling System Actuation Reports were examined to obtain the following summary of the events and the licensee's proposed corrective actions to prevent recurrence of these events:

(a) Safety Injections 1, 2, and 3 were caused by the premature lifting of a safety relief valve on a steam generator. Contrary to information from the manufacturer, the valve actuation setting changed during maintenance. The licensee instigated administrative controls such that in the future these type valves would be tested and adjusted as necessary after any maintenance actions that could affect the set point. All other like valves were tested after SI No. 3.

(b) Safety Injection 4 was caused when a technician mistakenly used grounded test leads when hooking up a brush recorder to various steam flow and steam pressure channels. The licensee verified this cause during a special test within a few days after Event 4. To prevent this type of occurence from repeating, all brush recorders were modified to allow use of grounded test leads. Technicians and their supervisors were advised of the modification.

(c) Event 5 was the result of an operator mistakenly setting the set point of a steam dump controller at 980 psig instead of the required 1005 psig. This setting in conjunction with a reactor trip opened the steam dump resulting in a high steam flow signal. A review of the incident reports did not reveal any proposed corrective action by the licensee.

(d) Safety Injection 6 was caused by failure to follow proper maintenance procedures. Maintenance personnel were repairing a hydraulic hose failure on No. 12MSIV without blocking the operation of the hydraulic valve motor. As fluid was added the valve cycled open resulting in a high steam line

differential pressure signal. Again, the ECCS report did not cite any corrective action to reduce the chances of a reoccurrence of this type.

(e) Safety Injection 7 resulted when an operator mistakenly pushed the wrong push-buttons while performing a surveillance procedure. The very close proximity of the controls was a contributing factor. No corrective action was given by the licensee in the ECCS report.

(f) Events 8 and 9 were caused by a misadjustment of a lead/lag controller in the steam dump system. Investigation after the latter incident by the licensee verified that the output of the controller was lagging the input, prohibiting the modulation of the steam dump valves, thereby causing T_{ave} to increase instead of being controlled at 547°F. A review of work orders and data cards revealed the controller was calibrated 14 months prior to the incidents and proper operation was verified at that time. No corrective action or administrative changes were cited by the licensee in his report.

(g) Safety Injection No. 10 occurred while the plant was in the process of cooldown from Mode 3 (hot standby) to Mode 5 (cold shutdown) with one reactor coolant pump operating. The steam generator (SG) atmospheric relief valves were being utilized to control the cooldown, with the operator monitoring the pressure in each of the four steam lines and adjusting the position of each SG atmospheric relief valve as necessary to maintain equal pressure in each steam line and obtain cooldown of the reactor coolant system.

With coolant pressure at 1500 psig and the reactor coolant T_{ave} at 403°F, a steam line ΔP trip occured causing a SI. Control room indication showed low pressure on one of the four steam lines with trips on two of the four steam line ΔP channels. A channel trip requires two out of three ΔP (≥100 psig) signals between a steam line and the remaining three steam lines.

Since Salem, Unit 1 does not have pressure recording instruments for the individual steam lines, the recorder traces of the reactor coolant temperatures prior to and during the incident were evaluated, and do indicate that a ΔP did exist between the steam generators of at least 60 to 70 psig. No instrument malfunctions were determined.

An evaluation of the incident indicates the following contributing factors:

(1) "Use of the atmospheric relief valves for reactor cooldown instead of the steam dump system."

The use of the SG atmospheric relief valves to cool down the reactor is a complex and difficult procedure. The operator is required to monitor each steam line pressure and individually operate the four SG atmospheric relief valves to maintain equal pressure between SGs to obtain the desired cooldown rate.

The Westinghouse-designed normal procedure for cooldown utilizes 12 steam dump valves connected to a common steam header to a condenser. A lead/lag controller (manual set

point) is used to open or modulate the required valves to regulate the steam dump rate and thus the reactor coolant cooldown rate. A swing check valve on each SG to header con- nection prevents backflow from the header and the other three SGs causing the heat transfer from the SGs to be self-regulating. Equal pressures will thereby be maintained in the SGs and steam lines.

(2) "Use of only one reactor coolant pump when utilizing the SG atmospheric relief valves during cooldown."

Two pairs of inlet nozzles are located on the opposite sides of the reactor vessel with each nozzle of a pair having 45° of azimuthal separation. The four nozzles are not equally spaced, and with only one reactor coolant pump (RCP) in operation, backflow occurs in the other three cooling loops and is the greatest in the nearest inlet nozzle. These different flow rates make the task of controlling the cooling rate of each SG difficult. By steaming through the atmospheric relief valves, a subcooling effect is produced in the two lowest reverse flow loops causing pressure in these loops to be lower. A slight adjustment in the set point on any of the atmospheric reliefs under these conditions can easily cause a 100 psig ΔP between loops resulting in a SI.

To prevent reoccurrences of this last type of SI, the licensee has proposed revising their plant Operating Instruction I-3.6, Hot Standby to Cold Shutdown, to reflect the following changes:

(1) Atmospheric relief valves will only be used for plant cooldown when the plant conditions prohibit use of the steam dump system

(2) Specific direction will be provided in the procedure for monitoring steam generator pressures when use of the atmospheric reliefs is required

(3) The procedure will require a minimum of two reactor coolant pumps, and that they be diagonally opposed, to be in service during plant cooldown.

The above changes will be in effect prior to the next reactor cooldown.

(h) Injection 11 was caused when the output transformer and regulating resistors of Bus 1B inverter failed initiating a reactor trip. While recovering from the trip, a high steam flow-low T_{ave} safety injection occurred as T_{ave} decreased below $543^{o}F$. As a result of this incident, a misaligned overspeed trip reset latch mechanism on an auxiliary feed pump and a faulty breaker for No. 11 RHR pump were found, corrected, and replaced, respectively. As of this date a formal ECCS Actuation Report has not been filed citing a cause, a corrective action, or precautionary measures to be taken to prevent an injection of this type from recurring.

3.0 CONCLUSION

3.1 Salem Safety Injections. Based on EI&C reviews of the Salem plant LERs and ECCS Actuation Reports there is no common cause for the eleven SIs at Salem.

The licensee-proposed procedural changes in regards to the use of atmospheric relief valves are satisfactory and will help prevent inadvertent SIs similar to No. 10. It is further recommended to the staff that pressure-recording instruments be added for each SG. Such instrumentation will enable more accurate analysis of any future SIs when the atmospheric relief valves must be used.

It is also concluded that the steps taken by the licensee to help prevent occurances similar to the first four are adequate.

Due to the abnormal number of personnel-error-caused SIs in this facility as compared to all other PWRs, a review of administrative controls and training procedures is recommended.

3.2 Generic SIs for PWRs. A review of the dockets for other PWRs for the past two years identified 12 other incidents of inadvertent SIs. These were distributed among several plants and resulted from an assortment of personnel errors and equipment malfunctions. The number and types of failures reported gave no indication that a generic problem of inadvertent SIs in PWRs exists.

4.0 REFERENCES

1. PSE&G letter (Schneider) to NRC (O'Reilly) dated February 24, 1977. (ECCS Actuation Report No. ECCS/77-01.)

2. PSE&G letter (Schneider) to NRC (O'Reilly) dated May 10, 1977. (ECCS Actuation Report No. 77-26/990.)

3. PSE&G letter (Librizzi) to NRC (O'Reilly) dated June 2, 1977. (ECCS Actuation Report No. 77-29/990.)

4. PSE&G letter (Librizzi) to NRC (Grier) dated February 10, 1978. (ECCS Actuation Report No. 78-04/990.)

5. Salem Unit 1, Technical Specifications, Appendix A to license DPR-70, August 13, 1976.