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SUBJECT: Responds to NRC 920814 ltr by addressing specific corrective actions re operability of alternate mini-flow lines for charging/safety injection pumps. Flow test will be conducted during upcoming refueling outage.

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SHEARON HARRIS NUCLEAR POWER PLANT
DOCKET NO. 50-400/LICENSE NO. NPF-63

OPERABILITY OF THE ALTERNATE MINI-FLOW LINES FOR THE CHARGING/SAFETY INJECTION PUMPS AT SHEARON HARRIS NUCLEAR POWER PLANT (TAC No. M84220)

Gentlemen:

The purpose of this letter is to provide CP&L's written response to those concerns identified in the NRC's August 14, 1992 letter and to address the specific corrective actions related to the operability of the High Head Safety Injection (HHSI) System at the Shearon Harris Nuclear Power Plant (SHNPP). These concerns were the basis for a presentation which Carolina Power & Light Company (CP&L) made to the NRC on August 20, 1992. CP&L fully understands the safety significance concerning the operability of the high head safety injection alternate mini-flow (AMF) system and has taken actions to preclude the possibility of water hammer type events in the future.

With respect to the potential issues which the NRC identified relative to system operability, the following are CP&L's responses as discussed on August 20, 1992:

1. The lack of analysis for system piping integrity as a result of at least four water hammer events:

    a. 1986 water hammer - no corrective action

    b. 1987 inadvertent safety injection - no corrective action

    c. 1990 weld leakage - no corrective action

    d. 1991 event (LER 91-008) - incomplete corrective action with an inadequate root-cause analysis.

In general, analysis for the effects of water hammer is ineffectual due to the complexity of the phenomena and the uncertainties involved. It is recognized in the industry that when a water hammer or other hydraulic transient occurs, inspection of affected components provides more conclusive information on system condition and/or damage than even the best analysis can provide. Likewise, water hammer loads are not normally considered in system design; industry practice is to minimize the potential for water hammer by design and by operating practice.

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During plant design, the AMF line was not considered to be susceptible to major water hammer due to its small size. The only hydraulic loading considered was the reaction from opening of the relief valve.

CP&L disagrees that there have been four water hammer events in the HHSI alternate mini-flow system. We are aware of one water hammer/pipe vibration event that occurred on August 7, 1986 while performing motor-operated valve testing as required by IE Bulletin 85-03. The only other occassion when a water hammer type event may have occurred was during an inadvertent safety injection on November 7, 1987. Each of the events cited by the NRC is addressed separately below:

a. 1986 Water Hammer

The 1986 water hammer/pipe vibration event was initially attributed to reverse flow through a Kerotest globe valve. An event involving Kerotest globe valves was reported in INPO SER 27-85, which was assessed for applicability at SHNPP in January, 1986. The engineer who performed the assessment also conducted the motor-operated valve test that caused the August, 1986 water hammer/pipe vibration event at SHNPP. When the event occurred, the engineer concluded that it was caused by reverse flow through the Kerotest globe valve. The affected lines were walked down for signs of pipe or hanger damage and none was identified. CP&L's experience with water hammer events indicates that any significant damage to piping would have been accompanied by visible major support damage and/or component dislocations. The procedure was revised to eliminate the reverse flow. When the revised procedure was run, no problems or abnormal transients were observed.

The relief valves were not considered to be related to the event and were considered to be capable of withstanding the pipe movement without damage (the valves and piping are seismically qualified). The motor-operated valves, which would be more susceptible to potential damage, were stroked without problems using the revised procedure.

The corrective actions for this event were appropriate for the root cause that was identified, considering what was known at that time about the AMF system. Performance of the revised procedure supported the conclusions that were made and corrective actions taken at that time.

b. 1987 Inadvertent Safety Injection

During this event, no one was in the vicinity of the pump discharge or AMF piping; thus, the occurrence of a water hammer/pipe vibration was and is indeterminate. Accordingly, corrective actions focused on the cause of the safety injection initiation. There was no plant-specific or industry information available at that time regarding the susceptibility of this system to water hammer/pipe vibration events. Routine operational inspections and monitoring of the system components subsequent to the event did not reveal damage indicative of water hammer.

Corrective actions were fully adequate based on the information available at the time.

c. 1990 Weld Leakage

The conditions related to the 1990 weld leakage were not consistent with a water hammer event. The affected piping is only 3/4 inch diameter and is not subject to flow during system operation; thus, a water hammer event would not be considered likely. Pinhole leakage is generally indicative of an inside-diameter initiated flaw.

The immediate corrective action to this condition was later found to be less than adequate. The significance of this condition was not recognized by Operations or Maintenance personnel at the time. Ideally, the affected component should have been evaluated for operability by engineering when the flaw was discovered and appropriate corrective actions taken. However, the leaks originally reported by Operations were not confirmed by the maintenance inspection.

d. LER 91-008

During the plant outage, the B train relief valve (1CS-755) was tested, but the set pressure could not be determined due to seat leakage in excess of the low flow capacity of the test rig (1 gpm). While valve 1CS-755 was removed, a drain connection on the B train AMF line failed following a surveillance test that flowed through a spool piece installed in place of 1CS-755. Due to the failure of 1CS-755, the 1CS-744 (A train) relief valve was tested and found with a low set pressure and internal damage. The significance of these failures was recognized and they were promptly reported to the NRC (INPO SER 20-91 was subsequently issued in September, 1991). The relief valves were repaired and retested. The B train drain line was repaired and the corresponding line on the A train examined by liquid penetrant (it was found to be cracked and was repaired). Tie-back supports were added to connect the drain lines to the header pipe.

The root cause investigation conducted at the time concluded that the most probable cause of the failures was one or more water hammer/pipe vibration events caused by trapped air in the relief valve inlet lines. Air could have been introduced by several maintenance and/or testing evolutions, and the system configuration made it unlikely that the air would be removed during restoration. Relief valve chatter was considered; Westinghouse was consulted and concurred that the relief valves were not susceptible to valve chatter as installed. At that time, it was concluded that when the AMF motor operated isolation valve opened, the acceleration of the high pressure water through the airspace ruptured the relief valve bellows and broke the spring.

Procedures were written to fill and vent the piping after relief valve installation and following any maintenance which could drain the piping. In situ quarterly tests were initiated to verify the

valve setpoints and ensure that the piping was filled (system configuration makes draindown unlikely, and isolation valve leakage would result in filling the line).

Operator training was also conducted on this event and on the potential operator actions that could be taken if the event recurred. The EOPs were reviewed to ensure that a condition involving a diversion of HHSI was adequately addressed.

A walkdown of the affected piping and hangers was performed and no damage was observed. A more thorough inspection was deemed unnecessary based on the results of the initial walkdown and the belief that an event severe enough to cause structural damage to the piping would cause visible damage to piping and/or supports.

An analysis for damage due to this event was unnecessary and impractical. Analytical techniques for transients of this type are very limited. An accurate analytical model is virtually impossible to develop without validation by testing. The transient flow characteristics of the isolation valve, which are essential to the model accuracy, would have to be assumed. Likewise, assumptions would be needed for relief valve response. The complexity of the transient two-phase response of the air space and water flow adds to the uncertainties in the analysis. Consequently, the results of any analysis would be virtually meaningless. The limitations of water hammer analysis are recognized by the industry and the NRC (e.g. NUREG-0927). Conversely, any significant damage from the event would be evident from inspections. In fact, the affected welds have subsequently been examined by liquid penetrant testing which confirms the conclusion that no damage occurred.

2. The potential for water hammer in the downstream portion of the AMF piping between the AMF safety relief valves (SRVs) and the refueling water storage tank.

The design of the subject piping is consistent with industry practice and in compliance with applicable codes and standards. Relief valve discharge loads, which had little impact, were calculated and incorporated into the existing stress analysis. The potential for significant water hammer in this piping is considered to be negligible based on the following:

The configuration of the line precludes water hammer. The relief valves discharge into 2-1/2 inch piping which leads to a 3 inch line which then feeds into a 6 inch header leading to a vented RWST; thus, the flow velocity will tend to decrease. There is a potential for air to accumulate in portions of the line, however, relief valve opening will tend to flush the air to the tank. The small bore piping on the relief valve discharge is likely to be water solid due to its location near the lowest elevation of the piping run.

The AMF line has been subjected to relief valve discharge at least three times during plant operation. Extensive inspections of piping welds and supports that were recently performed verified that no damage has occurred. Specifically, approximately thirty feet of pipe and four pipe

supports on the discharge side were examined. If a significant water hammer event had occurred in this section of the system, some damage would be evident.

3. The potential for valve chatter and setpoint drift for the SRVs.

The relief valves used were selected for this application by Westinghouse and the manufacturer (Crosby). Both Westinghouse and Crosby have confirmed that the valve design and the system configuration are such that chatter should not be a concern. The valve does not "pop" open to its full capacity when set pressure is reached; it modulates at an intermediate position while pump flow is divided between the injection path to the RCS and the AMF path. As pressure decreases, flow decreases until the valve reseats with a clean positive closing action. Spring tension is set and a locknut arrangement prevents drift of this setpoint. This locknut has never been found loose during valve testing or maintenance. If the valve opens at a pressure significantly above the setpoint, as it would when the isolation valve opens during an inadvertent SI actuation, the pump capacity is sufficient to keep the valve open. Only when the system pressure allows the pump to reach approximately 50% of its capacity will discharge pressure fall low enough to allow the valve to reseat.

With respect to the observed relief valve setpoint reduction, a broken spring was found in the affected valve whose setpoint had changed to approximately 1100 psig. No setpoint drift has been detected for the relief valve in its standby condition since quarterly testing was initiated in 1991. Since valve chatter is not predicted and since no movement of the spring locknut has been detected, no setpoint drift is anticipated if the relief valve lifts.

Operator Actions

The NRC staff also requested that CP&L take actions necessary to ensure that operators can detect an inadequate flow condition during the high head injection phase.

The HNP Emergency Operating Procedures (EOPs) are based on the Westinghouse Emergency Response Guidelines. These are symptom-based procedures which would provide operator guidance on responding to the event regardless of the cause of inadequate HHSI. The Emergency Operating Procedures provide immediate actions and diagnoses to mitigate an event based on the symptoms observed; i.e., RCS pressure, pressurizer level, etc. As a backup, critical safety functions are monitored to ensure the plant is maintained in a safe condition. For inadequate safety injection flow, the core cooling safety function monitors core conditions and operators would take additional mitigating actions as necessary to protect the fuel. In this event, this would result in depressurizing the Reactor Coolant System and initiating low head safety injection flow. The potential for including additional guidance in the ERGs for addressing this particular event was discussed at a Westinghouse Owners' Group meeting. The Westinghouse Owners' Group found the current guidelines appropriate and reaffirmed the use of the symptom-based procedures.

Specific guidance was provided to the SHNPP operators on this event by training and a revision to the EOP Users' Guides. This guidance included recognition and mitigation of a stuck open HHSI alternate mini-flow relief valve. Based on our review of the symptom-based Emergency Operating Procedures and the specific event-related training that has been performed, the operators would be able to respond to an HHSI alternate mini-flow failure.

Planned Actions

In order to confirm the conclusions discussed above, a flow test will be conducted during the upcoming refueling outage to verify proper system operation. Additionally, CP&L plans to continue quarterly testing to ensure piping is filled and to verify relief valve setpoints until we are confident that this event will not recur. An evaluation of alternate designs to eliminate the use of relief valves is also planned. These planned actions were outlined in the August 20, 1992 presentation to the NRC.

Core Damage Frequency

The NRC's August 14, 1992 letter stated that the HHSI event was assigned a conditional core damage frequency of 6.3×10^{-3} in a preliminary Oak Ridge accident sequence precursor study of 1991 events performed for the NRC. As discussed in a telephone conference call on August 28, 1992, CP&L understands that the conditional core damage probability value of 6.3×10^{-3} is a screening value used to identify potentially safety-significant precursor events, and is not comparable to the core damage frequencies typically calculated by probabilistic risk assessment. Specifically, the 6.3×10^{-3} value is derived from two conservative assumptions: (1) the high head safety injection system is completely ineffective (no credit taken for degraded performance of the system to provide some core cooling effect), and (2) the operator takes no action to mitigate the event. Based on our examination of the assumptions, we estimate that the actual conditional core damage probability is approximately one and one-half orders of magnitude less likely than the conditional core damage probability assigned by Oak Ridge. While CP&L agrees that this event was safety-significant, it is appropriate to acknowledge the conservative assumptions noted above in order to put the 6.3×10^{-3} value in perspective.

Please refer any questions regarding this submittal to Mr. R. W. Prunty at (919) 546-7318.

Yours very truly,

R A Watson

R. A. Watson

LSR/jbw

cc: Mr. S. D. Ebneter
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