U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-423/88-08

Docket No. 50-423

License No. NPF-49

Licensee: Northeast Nuclear Energy Company
P.O. Box 270
Hartford, CT 06101-0270

Facility Name: Millstone Nuclear Power Station, Unit 3

Inspection At: Waterford, Connecticut

Inspection Conducted: 4/5/88 - 5/23/88

Reporting Inspector: G. S. Barber, Resident Inspector

Inspectors: W. J. Raymond, Senior Resident Inspector
G. S. Barber, Resident Inspector

Approved by: E. C. McCabe, Jr. 6/3/88
E. C. McCabe, Chief, Reactor Projects Section 1B Date

Inspection Summary: Inspection on 4/5/88 - 5/23/88

Areas Inspected: Routine resident inspection (158 hours) of: Plant Operations; Reported Foul Smell; Plant Operational Status; Safety System Operability; Full Power Reactor Trip - 4/13/88; Reactor Vessel Head Seal Inner O-Ring Leak; Two Consecutive Unusual Events due to Reactor Coolant System (RCS) Leakage; Inoperable Containment Isolation Valves for Sample Lines; Environmental Qualification of General Atomic High Range Radiation Monitor Cabling; Licensee Event Reports (LERs); Maintenance; and Surveillance.

Findings: No violations or deviations were identified. Licensee action to cool down the plant with unidentified leakage slightly less than the TS limit was conservative and appropriate. The lack of positive action to terminate a second Unusual Event involving RCS leakage caused heightened attention by the NRC Operations Center; the licensee promptly initiated a procedure change to require positive termination of Unusual Events by the Shift Supervisor.

The reactor trip on April 13 indicated a need for additional management attention to degraded equipment in the Intake Structure. Unavailability of multiple similar components in the intake was viewed as a direct contributor to the reactor trip. Since this incident, the inspector has observed a heightened concern to this issue by management.

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DETAILS

1.0 Persons Contacted

Inspection findings were discussed periodically with the supervisory and management personnel identified below:

S. Scace, Station Superintendent
C. Clement, Unit 3 Superintendent
H. Haynes, Station Services Superintendent
M. Gentry, Operations Supervisor
R. Rothgeb, Maintenance Supervisor
K. Burton, Staff Assistant to Unit Superintendent
J. Harris, Engineering Supervisor
D. McDaniel, Reactor Engineer
R. Satchatello, Health Physics Supervisor
M. Pearson, Operations Assistant

2.0 Summary of Facility Activities

The plant was at 100% power at the beginning of the inspection period. A power reduction occurred at 6:02 a.m., April 7 to perform Reactor Protection System (RPS) testing. The plant returned to 100% power at 11:50 a.m. that day. The plant continued to operate at full power until a reactor trip at 4:52 p.m., April 13 due to a turbine trip from low condenser vacuum (see Detail 5.0). While the plant was shutdown, a leak developed in the inner O-ring for the Reactor Vessel Flange (See Detail 6.0) at 1:02 p.m., April 14. The leak was isolated at 1:17 p.m. and a containment entry was made to realign the seal leakoff line to the outer O-ring. The remote leakoff isolation valve was reopened at 2:34 p.m. and there was no observed temperature increase in the leakoff line.

Later that day, RCS unidentified leakage increased to 5 to 6 gpm. The leak was into the Containment Drain Transfer Tank (CDTT) and caused tank pressure to exceed 100 psi, with the CDTT relief continuously lifting. The leak was isolated during a subsequent containment entry and identified to be from the "B" PORV (Power Operated Relief Valve) block valve stem leakoff line. Further RCS leakage was discovered and corrected (see Report Detail 5.3).

This newly discovered unidentified leakage was close to but less than the leakage limit of 1.0 gpm. The licensee declared an Unusual Event (see Detail 7.0) and began a cooldown to cold shutdown at 5:21 p.m., April 15. Mode 5 was reached at 7:15 p.m., April 16. The shutdown was necessary to repair valve body-to-bonnet leaks that caused the leakage. At 3:45 p.m. on April 24, heatup began and the reactor was made critical at 6:32 p.m., April 26. Mode 1 was entered at 10:34 p.m. that day. The generator was synchronized on the grid at 11:13 a.m., April 27 and power escalation began.

The discovery of a small steam leak on a Main Steam drain line required a downpower at 12:30 p.m., April 28, with the turbine generator going offline at 2:16 p.m. The generator breaker was reclosed at 10:30 p.m. after repairs were completed, and the unit reached 100% power at 2:14 p.m., April 30.

Plant power remained at 100% until 9:00 a.m., May 11, when a 10% power reduction was necessary for a thermal backwash of the main condenser. A leaky water box outlet cross-tie valve caused a further power reduction to 82% at 3:10 p.m., when vacuum was lost as a result of air binding of the "B" water box. An additional 10% power reduction was necessary for thermal backwashing on May 14, at 5:00 a.m. The plant returned to full power until the end of the inspection period except for 2% to 4% power reductions for Overtemperature/Overpower delta temperature spiking and RPS testing.

3.0 Reported Foul Smell

At 10:15 a.m., April 18, the inspector was contacted by a citizen who lived east of the plant, across Jordan Cove, regarding an unusual odor he detected from 2:00 p.m. to 8:00 p.m., April 17. The individual described a metallic odor that permeated the air and stated that he believed that it was the smell of radioactivity mixed with water. The inspector explained that radioactivity was undetectable to all five senses and any odor he smelled would have to have been from a chemical or contaminant in the water or air. The individual stated that he also smelled the foul odor the week before but it was not as strong and the winds were also from the Southwest as they were on April 18. The inspector forwarded the concern to Regional management; a Region I allegation panel meeting was held to discuss the matter. The panel concluded that the matter could best be investigated by the licensee with oversight by the inspector. The inspector reviewed the matter with the licensee in a meeting on April 29.

After reviewing the issues on April 29 with the inspector, the station services superintendent forwarded the matter to the station chemistry supervisor, who provided the following information. The station chemistry supervisor contacted the individual by phone that evening and on May 1, and visited him at his residence on May 3. The individual again described the odor as a strong, metallic-like odor. It was explained to the individual that station personnel would review operations at the plant in detail to determine if any connection could be made between plant operations and the odor. It was also agreed that the individual would be provided sampling apparatus and a telephone number for contacting station personnel should the odor recur. From the licensee's discussions with the individual, no connection was made between the odor and any site releases or activities.

After the licensee's meeting with the individual, their investigation concluded that the odors were not caused by Millstone Station. The licensee's investigation included a detailed review of operating logs and routine evolutions such as system venting, sea water chlorination, emergency diesel generator operations, and painting. No unusual activities were discovered.

The licensee also performed an evaluation of other potential industrial sources in the southeastern Connecticut area. The licensee contacted several local industries including Pfizer Incorporated, the New London Sewage Treatment Plant, and the Plum Island Animal Disease Center. No correlation was made between these facilities' activities and the reported odor.

Licensee personnel will respond if the odor is detected again. Station personnel have assembled sampling apparatus for this purpose and are prepared to support this effort once notification is received from the individual. The individual seemed satisfied with the efforts taken to address his concerns.

The Connecticut Department of Environmental Protection (DEP) is also pursuing this matter in response to a letter that the individual wrote to the Governor's office. The licensee has been in contact with the DEP to keep them fully aware of the licensee's activities. The DEP reportedly plans to report their findings to the alleger by the end of May.

The licensee plans to communicate their findings to U.S. Congressman Gejdenson's office at his request. In addition, the licensee plans to correspond with the individual in writing to provide a detailed accounting of their investigation.

The inspector independently reviewed the control room logs for April 17 and verified that there were no unusual operations or offsite releases. Also, the inspector reviewed the licensee's investigation, found it to be very responsive, and concurred that the reported foul smell was not attributable to Millstone. A May 20, 1988 letter from NRC Region I to the individual described the NRC follow-up and conclusions. Inspector discussions with the licensee indicate that satisfying the concerns of this individual and of the community as a whole is important to them. The inspector had no further questions on this matter.

4.0 Plant Operational Status Reviews

The inspector reviewed plant operations from the control room and reviewed the operational status of plant safety systems to assess safety of operation of the plant in accordance with the technical specifications and plant operating procedures. Actions taken to meet technical specification requirements when equipment was inoperable were reviewed. Plant logs and control room indicators were reviewed to identify changes in plant operational status and to determine whether equipment status changes were properly communicated in the logs and records. Control room instruments were observed for correlation between channels, proper functioning, and conformance with technical specifications. Alarm conditions in effect were reviewed with control room operators for proper response to off-normal conditions and operator knowledge of plant status. Operators were found to be cognizant of control room indications and plant status. Control room manning and shift staffing were reviewed and compared to technical specification requirements. No inadequacies were identified. The following specific activities were also addressed.

4.1 Safety System Operability Review

The high pressure safety injection, quench spray, auxiliary feedwater, recirculation spray, charging, residual heat removal, safety injection accumulator, and the emergency diesel generator systems were reviewed for operability in the standby mode. The review included consideration of: proper positioning of major flow path valves; operable normal and emergency power supplies; ind'-ators and controls functioning properly; and a visual inspection of m or components for leakage, cooling water supply, lubrication and general condition. No inadequacies were identified.

5.0 Review of Facility Activities

5.1 Full Power Reactor Trip - 4/13/88

The reactor tripped from 100% power due to a turbine trip at 4:52 p.m., April 13. The turbine tripped on low condenser vacuum caused by a loss of 2 of 6 (A & B) circulating (CW) water pumps. The CW pumps tripped due to high differential pressure (dP) on the travelling screens in the affected CW intake bays. The CW pumps tripped as required when dP reached 30 inches of water. The excessive screen dP was caused by seaweed and other debris impacting the operating screens while the operating screen wash pump (SWT-P1B) was out of service for cleaning its strainer.

The redundant screen wash pump (SWT-P1A) had been out of service for maintenance. It was most recently tagged out (88-4648) on March 14. This pump was also out of service (OOS) in February due to high vibrations. Maintenance disassembled this pump and found that the bearings were wiped. The bearings were replaced but high vibration persisted and the pump was left out of service with the March 14 tags.

On April 13, a Plant Equipment Operator (PEO) went to the intake structure and took the operating screenwash pump (SWT-P1B) OOS in response to a high strainer dP alarm received in the control room. The PEO began to clean the SWT strainers, expecting it to take 20-30 minutes before they were restored to service. Screen dP was at zero at the time SWT-P1B was shutdown. About 10 minutes into the cleaning operation, Control Operators (COs) noted that dP across the "A" screen was increasing, began an immediate downpower, and directed the PEO to close up the strainer and restore SWT-P1B to service. The SWT was restarted at 4:50 p.m. However, it was not returned to service soon enough to prevent a trip of both the "A" & "B" CW pumps (CWS-PIA/PIB), which led to the turbine/reactor trip.

Plant systems responded as expected to the turbine/reactor trip. The inspector responded to the control room (CR) and observed completion of the post-trip recovery actions specified in procedures EO and ES0.1. The plant was stabilized at no load temperature and pressure. The inspector independently reviewed the sequence-of-events printout to determine if plant response was other than expected. No inadequacies were noted.

The inspector reviewed the licensee's root cause determination and noted no inadequacies. However, the inability to use a system design feature directly contributed to the trip. The duplex SWT strainer for each SWT pump has dual baskets that are divided into compartments designed to allow isolation to clean of 1 of the 2 baskets while the SWT pump remains in operation. This design feature was not utilized because the individual compartment isolation valves were leaking by, which forced the operable SWT pump to be shut down to clean either of its strainer baskets. Consequently, the debris that impacted the travelling screens clogged it and started the trip sequence.

While the plant was shutdown, a leak developed in the inner O-ring for the Reactor Vessel Flange (See Detail 5.1). The leak was subsequently isolated. Further plant problems with RCS leakage precluded immediate plant startup (see Detail 5.2). A cooldown to cold shutdown (Mode 5) was completed at 5:2[illegible], April 15. Mode 5 was reached at 7:15 p.m., April 16. The shutdown was necessary to repair body-to-bonnet leaks in valves that caused the RCS leakage. During the shutdown, the faulty screenwash pump was also repaired and the screens were completely cleared of debris. At 3:45 p.m. on April 24, heatup was began. Heatup continued and the reactor was made critical at 6:32 p.m., April 26 with Mode 1 (power operation) being entered at 10:34 p.m., that same day. The generator was synchronized on the grid at 11:13 a.m., April 27.

5.2 Reactor Vessel Inner O-Ring Leak

The licensee reported that a leak in the Reactor Vessel (RV) Inner O-Ring seal developed at 12:45 p.m., April 14. The leak was identified when the computer leak rate program indicated a leak rate of four gpm with a RV O-ring seal telltale drain high leakoff temperature. That temperature peaked at 250 degrees F. Operators took prompt action to isolate the leak by closing the telltale drain leakoff isolation valve (RCS-AV8032) directed to the Containment Drains Transfer Tank (CDTT). Once isolated, telltale drain temperature slowly decreased to 75 degrees F.

After telltale drain isolation, the leak rate remained at four gpm. A containment entry was made to search for leaking components. During the entry, the upstream manual isolation for the inner O-ring was closed and the isolation for the outer O-ring was opened to detect any degradation in the outer O-ring. No such degradation was detected. Other checks found the "B" Power Operated Relief Valve (PORV) to have a packing leak. The hot leakoff from the RV inner O-ring was hypothesized to have upset the packing of the "B" PORV block valve, causing it to leak. Contact pyrometer readings on the leakoff line were consistent with a packing leak (see Detail 5.3). The CDTT relief valve lifted until the "B" PORV block leakoff was isolated.

The inspector observed operator actions in the control room to isolate the RV O-ring leakoff and noted that they were prompt and in accordance with the appropriate abnormal operating procedure (AOP). In addition, the inspector noted no temperature increase when the telltale drain was opened after realignment to the outer O-ring. Therefore, the outer O-ring was properly energized and leak tight.

When questioned about the O-ring's history, the licensee stated that the inner O-ring had also failed early during the first cycle and that there was no leakage experienced through the outer O-ring. (Both O-rings are routinely replaced during refueling outages.) The inspector requested that the licensee provide a safety evaluation assessing whether further degradation in the RV O-ring seals was within the FSAR Safety Analysis.

The licensee provided the following safety evaluation:

> The function of the RV O-Rings is to provide a zero leak seal at the vessel/closure head flange mating surfaces during all phases of reactor operation. Absence of the total seal during plant heatup would preclude full pressurization of the RCS and the plant could not go to power. Failure of the O-rings during plant operation would begin with a small, slow leak which would be detected by the O-ring leakage monitoring system. The plant could then be brought to a safe shutdown condition. No catastrophic failure of the redundant O-ring seal system can be postulated. Therefore, failure of the O-ring does not endanger public safety.
>
> The above assumptions on catastrophic failure mechanisms can be made since the vessel-to-head mechanical joint is essentially a metal-to-metal joint maintained by the reactor vessel studs. In addition, with the inner O-ring failed as a leak-tight seal, it would still restrict flow even if the outer O-ring were to fail. A leak past the second O-ring is slow to develop, easily identified, and has been demonstrated at several plants to be within the capabilities of one charging pump. A calculation shows that, in the highly unlikely event that both O-rings are completely destroyed or blown out, the leakage would be well within the analysis for a small break LOCA.

The inspector reviewed the calculation and noted that the licensee's assumptions were extremely conservative and that the postulated failure mechanisms were well within the small break LOCA analysis. The licensee postulates that the O-ring failures were caused by boric acid attack. During RV head seating, a "squish" of water is sent up the inner walls of the vessel and out into the inner O-ring area. This is believed to leave small pockets of residual boric acid in contact with the O-ring. Any drying and rewetting of the area provides a concentrating mechanism to foster acidic attack of the O-ring. Lowering of water level by four or five feet below the flange level is necessary when seating the head to prevent such a "squish." The licensee is planning to implement this action during future refuelings.

5.3 Two Consecutive Unusual Events Due to RCS Leakage

On April 14, the plant was in hot standby after an April 13 plant trip (see Detail 5.1) due to loss of condenser vacuum caused by high circulating water traveling screen differential pressure. At 5:15 p.m., April 14, an Unusual Event was declared when Reactor Coolant System (RCS) unidentified leakage increased to approximately 6 gpm. This leak rate is greater than the Technical Specification (TS) leak rate limit of 1.0 gpm for unidentified leakage. The licensee identified that the inner of two Reactor Vessel (RV) O-rings (see Detail 5.2) had begun to leak at 12:45 p.m. That sent hot steam to the Containment Drain Transfer Tank (CDTT). The licensee detected the leak by noting increasing pressure in the CDTT and increased containment gaseous radiation concentration after the CDTT relief lifted. The 6 gpm leakage began after the telltale drain from the inner O-ring cavity was isolated. Feedback to valve stem leakoffs directed to the CDTT is hypothesized to have caused other leakage to begin.

A containment entry was made at 8:00 p.m., and a leak was identified from the "B" PORV (Power Operated Relief Valve) block valve packing leakoff line. A manual valve in the leakoff line was shut at 9:10 a.m., April 14 isolating the leak. CDTT pressure then dropped below the 75 psi relief setpoint and the CDTT relief reset. The licensee concluded the leak had been found and that the "B" PORV block valve's outer packing and lantern rings were holding, and terminated the Unusual Event at 9:30 p.m. On the following day, April 15, at 1:52 p.m., the licensee noted that RCS unidentified leakage was 0.9 gpm, and re-declared an unusual event. A containment entry began about 3:00 p.m. to try to identify the leak and investigate high temperature (greater than 120 degrees F) in the pressurizer cubicle. The licensee found that the Loop 1 charging stop valve had a body-to-bonnet leak that was spraying an amount of steam that could not be quantified. This was suspected to be the major source of leakage, however, additional leakage was noted from a body-to-bonnet leak from a downstream check valve and from the Loop 1 hot leg (Th) loop stop valve. Originally, the Th loop stop leak was thought to be from the packing based on boron encrustation on the valve body. Closer licensee inspection revealed the leak's location as from the body-to-bonnet area. The high pressurizer cubicle temperature was due to weepage past the seat of the "C" pressurizer safety valve. The licensee noted that repair of the body-to-bonnet leaks required a cooldown to cold shutdown (Mode 5). Thus, a cooldown was begun at 5:30 p.m., April 15, to repair the leaks. The licensee entered Mode 5 at 7:15 p.m., April 16.

The licensee's cold shutdown work lists included work required to meet earlier commitments. In addition to the valve leak repairs, the following work was performed: Target Rock solenoid-operated valve repair (Containment isolation valves for sample lines); slave relay testing; Litton-Veam connector looseness checks and silicone gasket replacement; "C" pressurizer safety valve changeout; Containment Drain Transfer Tank (CDTT) gage glass replacement and tank leak tightness evaluation; "B" Control Rod Drive Mechanism Spot Cooler Chill Water relief valve replacement; and other scheduled surveillance, preventive and corrective maintenance. Scheduled work was completed as required and the plant was heated up and restarted. Licensee action during the Unusual Events showed a due regard for safety. However, the licensee did not terminate the second Unusual Event by notifying the NRC personnel monitoring plant status in the NRC Operations Center. The licensee has implemented a procedure change to EPIP 4701 to require the termination of an Unusual Event on the NRC ENS line. The inspector had no further questions.

5.4 Inoperable Containment Isolation Valves for Sample Lines

On March 1, while performing the biennial sample line valve position indication testing, the licensee discovered that two inside containment isolation valves would not open and a third isolation valve inside containment was leaking. Specifically, the Pressurizer Relief Tank (PRT) gas sample line (3/4") isolation valve (3SSR*CV8026) and the pressurizer vapor space sample line (3/4") isolation valve (3SSR*CTV20) would not open. This precluded surveillance of the outside containment isolation valves 3SSR*CV8025 and 3SSR*CTV21. The third valve, a pressurizer liquid sample line (3/4") isolation valve (3SSR*CTV22), was leaking. Therefore, these valves were considered to be inoperable on March 1 and compensatory measures were taken as required by the ACTION statement of TS 3.6.3.b. Specifically, the corresponding outside containment isolation valves 3SSR*CV8025, 3SSR*CTV21, and 3SSR*CTV23 were closed and power was removed from the valve operators. The plant was in Mode 1 at that time and continued power operation until the unit tripped on April 13. The plant could not be started up with these sample valves closed since TS 3.0.4 is applicable to TS 3.6.3.b.

TS 3.0.4 states that entry into an operational mode or other specified condition shall not be made unless all LCOs are met without reliance on the provisions of ACTION statements. The intent is to ensure that a higher mode of operation is not entered when equipment is inoperable. This precludes a plant startup if an LCO is not met, even if the ACTION statements would permit continued operation of the plant. Some individual specifications have ACTION statements which allow continued operations when in the LCO and/or note that Specification 3.0.4 does not apply. TS 3.6.3.b did not have this exception. However, the licensee believes that the most limiting aspect of the LCO was met and pursued an emergency TS amendment and a concurrent temporary waiver of compliance.

In a letter dated April 14, 1988, the licensee requested this temporary waiver of compliance from TS 3.0.4 application to LCO 3.6.3. This relief was requested to permit the plant to return to power operation after the trip on April 13. In a letter dated April 15, 1988, the staff granted a temporary waiver of compliance; this waiver was to be in effect until the NRC staff completed the processing of an emergency license change request. The licensee's emergency license amendment request was submitted to the NRC on April 15. However, as a result of the unisolable leak in the charging portion of the reactor coolant system, the plant was taken to cold shutdown on April 16. While in cold shutdown, the licensee repaired/replaced the inoperable sample line isolation valves 3SSR*CTV8026, 3SSR*CT 20 and 3SSR*CTV22 inside containment.

If a similar situation occurs before the license amendment request is processed, the licensee will again need NRC approval of this license amendment on . emergency basis. Therefore, the licensee requested that the NRC staff take necessary steps to approve the license amendment request upon completion of the requirements specified in 10 CFR 50.91. The inspector reviewed the safety significance of operating with the sample valves isolated and noted that the licensee's emergency procedures do not require their operation. The post-accident sample system would be used in the LOCA environment. However, these sample points are used during cooldown to verify pressurizer boron concentration is comparable to RCS boron concentration. Sample valve failures require the licensee to obtain equivalent information by alternate sample points or calculational methods. Additionally, the design of the pressurizer liquid space sample line incorporates a drain from the pressurizer relief valve loop seals. The draining of these lines into this sample line results in a nonrepresentative sample and inability to ensure appropriate boron concentration based on this sample point. The licensee is proposing a calculational methodology to verify boron concentration during normal cooldown. The adequacy of this calculation will be reviewed after its completion.

6.0 Environmental Qualification of General Atomic High Range Radiation Monitor Cabling

Sorrento Electronics (SE) (affiliated with General Atomic) issued a 10 CFR Part 21 notification regarding the coaxial cable used with their high range radiation monitors (3RMS*RE04 and RE05). The licensee uses these monitors and coaxial cabling inside containment. Located inside containment above the operating flow, these monitors detect radiation levels (post-accident) between 1 R/hr and 10 million R/hr. SE identified that the Rockbestos RSS6-104 coaxial cables used at Millstone 3 exhibited unsatisfactory insulation resistance above 350 degrees F. At these temperatures, the electrical insulation resistance decreases, increasing leakage currents which oppose detector currents which in turn reduce indicated radiation levels.

Sorrento Electronics correspondence with the licensee dated March 24, 1987 and April 9, 1987, described and revised a heat transfer calculation that could be used to determine the acceptability of the coaxial cables for a LOCA environment. The calculation method calculates leakage currents using the temperatures generated from the licensee's DBA LOCA profile. The calculation uses the insulation resistance versus temperature that was provided by the Rockbestos EQ reports. The following reports were provided as Attachments to the SE correspondence:

Attachment 2: Excerpt from Rockbestos Report No. 2806, April 23, 1982 (Revised January 5, 1983 and June 1, 1983)

Attachment 3: Excerpt from Rockbestos Report No. QR-6810, February 21, 1986

Attachment 4: Excerpt from Rockbestos Report No. QR-6802, March 12, 1986

Attachment 1 provided the actual calculational methodology. The methodology provided was an approach that SE used to determine the temperature of a cable in the LOCA environment. It was essentially a hand calculation that can be performed with a desk calculator. It was verified by a second SE engineer using a computer model and was found to be in agreement with the computer model.

The licensee implemented the SE calculational methodology to qualify the RSS-6-104 Rockbestos coaxial cables for their plant specific DBA (design basis accident) LOCA in engineering calculation 3-ENG094, Rev. 1 dated April 23, 1987. The inspector reviewed the calculation to ensure: the assumptions were valid; the calculation used test data applicable to MP3; the same samples were used in each qualification report; and that data included was properly translated and used in the calculation.

The heat transfer calculation assumptions used by the licensee were found reasonable and comparable to those provided by SE. The analysis of the cable insulation involved solving a differential equation that equates the changed internal energy of the cable insulation to the heat transfer into the cable insulation from the containment atmosphere during a LOCA. The solution of the equation is similar to the solution of a transient heat conduction problem involving conduction of heat through cylindrical heat insulators of varying diameters. Due the force of gravity, the cable was assumed to be in primary contact with a 20 degree arc of the conduit. Heat transfer area was based on this 20 degree arc. The remaining 340 degrees of cable would be at a lower peak temperature because of the air gap, and the insulation effects of the air gap are not included in the calculation. The thermal resistance of the various insulation materials was calculated and summed to derive an equivalent total resistance. The licensee's LOCA profile wa superimposed on a curve of containment temperature versus time to calculate the maximum cable temperature at the conductor (conservative assumption used temperature at the mid-plane of the second insulator). An iterative process was used in the following calculation to generate the following temperature table.

$$T(t) = Tc + (To-Tc) \exp(-0.0029Xdt)$$

where, T(t) = cable temp at time dt in seconds
Tc = containment temperature from LOCA profile
To = cable temperature from previous time increment (dt)
dt = elapsed time from LOCA initiation
MNE = Maximum Normal Excursion temp
All temperatures are in degrees F

dt	To	Tc	T(t)
0	MNE = 120F	--	120F
3	120F	182.7F	120.5F
6	120.5F	245.4F	121.5F
9	121.5F	308.2F	123F
11	123F	350F	124F
44	124F	345F	144F
77	144F	341F	162F
110	162F	336F	178F
130	178F	324F	186F
150	186F	312F	193F
171	193F	300F	199F
325	199F	265F	222F
1800	222F	265F	264F Peak Temperature
2990	264F	150F	153F

Therefore, the licensee should base their minimum electrical resistance on a peak temperature of 264 degrees F.

As documented in the manufacturer's Report on Qualification Test for Rockbestos Adverse Service Coaxial, Twinaxial, and Triaxial Cable, General Nuclear Incident for Class 1E Service in Nuclear Generating Stations (QR 6802), cable samples were tested for a LOCA environment. Cable samples for this program were manufactured under a standard production order utilizing normal manufacturing techniques and materials. Completed cable lengths were sufficient to provide a selection consistent with random sampling philosophy. All samples were approximately 18 feet, taken from completed cable. The RSS-6-104/LE samples for the plant were done as a part of sample lot "B" which were thermally aged at 100 degrees C for a period of 120 hours and irradiation aged to achieve a total exposure of 200 megarads. Applied detector voltage on the in-plant detectors is 865 volts. However, the cable voltage that determines the maximum instrument error is only 0.001 volts and the measurement of the leakage currents at higher voltages is conservative with respect to the instrument voltage.

Insulation resistance was measured during the LOCA test at 500 Volts for 1 minute for 1000 ft. of cable in megohms as:

Time	Temp*	Sample Resistance (Megohms/1000 ft) B2	B4
Prod Test	RT	1,530,000	1,530,000
Pre Exam	RT	360,000	360,000
Pre LOCA	RT	630,000	900,000
8 Hrs.	341.8	0.468	1.188
11 Hrs.	322.2	0.918	1.476
15 Hrs.	301.6	2.340	2.700
18 Hrs.	251.3	46.80	43.20
4 Days	226.9	180.0	252.0

*RT = Room Temperature. Otherwise, temperature is in degree Fahrenheit (F).

The minimum resistance values were used by the licensee to calculate the maximum leakage current of 1E-11 amps, which equates to a maximum error of 1 R/hr. Therefore, the licensee concluded that the factor of 2 accuracy specified Reg. Guide 1.97 was met.

The inspector reviewed the calculation in detail and concurred that the methodology used would accurately describe the cable's temperature profile. No assessment of the actual qualification test methodology was provided during this review. The inspector did not concur with the licensee's maximum error determination because of the following discrepancies. Resolution of these discrepancies and reinspection of the revised calculation is needed.

Calculation Discrepancies

1. Report on Qualification Test for GA Technologies for Insulation Resistance vs. Temperature, QR-6810, described the sample as being thermally aged for 700 hours at 120 degrees C to simulate the 40 year life. QR 6802 thermally aged the test samples for 120 hours at 100 degrees C which, if linear, would equate to a thermal life of less than 7 years. The licensee's calculation used the QR-6802 thermal life and did not disposition the differences in the thermal aging between the two qualification reports. Increased cable replacement frequency may be required if the shorter thermal age qualification is the limiting one.

2. The insulation resistance used by the licensee corresponded to a temperature of 251.3 degrees F (43.20 Megohms per 1000 ft). The earlier data point was 301.6 degrees F (2.700 Megohms per 1000 ft) and shows a significantly reduced insulation resistance. Linear interpolation of the temperature difference between these two points yields an insulation

resistance of 32.98 Megohms per 1000 ft, which will change the magnitude of the maximum error. Linear interpolation between these points may be invalid because insulation resistance variance with test stand temperature may be substantively non-linear.

Until these two items are resolved, calculation validity is in question. This is an unresolved item (UNR 88-08-01).

7.0 Review of Licensee Event Reports (LERs)

Licensee Event Reports (LERs) submitted during the report period were reviewed to assess LER accuracy, the adequacy of corrective actions, compliance with 10 CFR 50.73 reporting requirements, and to determine if there were generic implications or if further information was required. Selected corrective actions were reviewed for implementation and thoroughness. The LERs reviewed were:

-- LER 88-005-00, Cold Overpressure Protection System Fails to Operate During Pressure Transient. Inspection Report 50-423/88-03 provides a detailed review of this event.

-- LER 88-012-00, Failure to Monitor an Inoperable Fire Door (NC4 88-08-02). This licensee-identified item was evaluated as being of low safety significance, appropriately reported and corrected, and not a result of inadequate corrective action on a prior violation. Therefore, no Notice of Violation was issued.

-- LER 88-013-00, Incomplete Installation of Damper Circuit in the Hydrogen Recombiner System.

No inadequacies were noted.

7.1 Environmental Qualification Related Licensee Event Reports (LERs)

The inspector reviewed Environmental Qualification (EQ) related Licensee Event Reports (LERs) provided by the licensee. The LERs were requested to determine whether any EQ issues were still unresolved. This review was to specifically highlight any EQ related equipment operability problems. The licensee provided the following listing of LERs:

-- 86-16-00, Area Temperature Monitoring CS-01
-- 86-16-01, Area Temperature Monitoring CS-01
-- 86-29-00, Area Temperature Monitoring ES-07
-- 86-50-00, Area Temperature Monitoring MS-01
-- 86-50-01, Area Temperature Monitoring MS-01
-- 86-50-02, Area Temperature Monitoring MS-01
-- 87-06-00, Missed Temperature Monitoring Surveillance
-- 87-19-00, Area Temperature Monitoring ES-07

-- 87-23-00, Area Temperature Monitoring CS-01
-- 87-23-01, Area Temperature Monitoring CS-01
-- 87-50-00, Missed Temperature Monitoring Surveillance

Eleven LERs were reviewed. Three events required supplemental LERs to fully describe the events and address appropriate corrective action. Seven distinct events were described in the eleven LERs. The event types were placed in two categories: Temperature Excursions and Missed Surveillances.

Temperature excursions occurred in three EQ zones (CS-01, ES-07 and MS-01). The affected zones were the containment area inside the crane wall (CS-01), specifically the pressurizer cubicle; the turbine-driven auxiliary feedwater (TDAFW) pump room (ES-07), and the Main Steam Valve Building (MS-01). All of these LERs were submitted as special reports for area temperatures exceeding the temperature limit for more than 8 hours, but remaining within 20 degrees F of the limit.

LER 86-16-00 and its supplement described a condition where the pressurizer cubicle inside containment exceeded the 120 degree F limit. Area temperature reached 125 degrees F. Affected components in the area were the PORVs and their block valves and the Reactor Vessel Head Vents. The licensee performed calculations of continued operability of these valves. The licensee concluded that the equipment remained operable, however, some adjustments were made to the equipment's qualified life. In addition, the licensee concluded that, during continued plant operation, pressurizer cubicle temperature will continue to range in and out of the Plant Technical Specification limit. As a corrective action, the licensee submitted a change to Plant TS Table 3.7.6 to create a new temperature monitoring area, CS-03, containment area, pressurizer cubicle. Licensee engineering will determine a new temperature limit for the area and revise thermal life calculations accordingly. LER 87-23-00 and its supplement identified a temperature excursion in the same area and reiterated similar concerns identified in LER 86-16-00 and its supplement. Licensee root cause identification and corrective actions were found appropriate. No inadequacies were noted.

LERs 86-29-00 and 87-19-00 described a temperature excursion in the TDAFW pump room. Both LERs describe the causes of the events as temporary (Loss of Air Conditioning) and included appropriate operability evaluations. No inadequacies were noted.

LER 86-50-00 and its supplements identified temperature excursions exceeding the 120 degrees F limit in the Main Steam Valve Building (MSVB). The licensee performed an analysis for continued operability at a sustained temperature of 130 degrees F. The shortest thermal life for environmentally qualified equipment under these conditions is greater than five years. As a corrective action, temporary plant modifications were implemented with some success. However, the temporary modifications by themselves were not sufficient to keep area temperatures below the Technical Specification limit for all operating conditions. Therefore, a permanent modification to the building's heating and ventilation system was initiated. It involved the use of a "spot cooling" design. This design provided cooling ducts near environmentally qualified equipment. Testing indicated the need for additional modifications, which are currently under engineering review. The permanent power and control equipment have not been installed pending the establishment of proper plant conditions. However, the modification for the most part is effective and operable utilizing temporary power. The modification was installed during the October 1987 refueling outage. Final testing of the system will take place during the summer of 1988 to measure the effectiveness of the modification in warm weather. Modification effectiveness will be evaluated in future inspections.

LERs 87-06-00 and 87-50-00 involved missed surveillances of EQ related equipment. LER 87-06-00 documented the failure of a Plant Equipment Operator (PEO) to take a temperature reading. The Shift Supervisor (SS) also missed the blank entry on his review of the logs. The licensee noted that auxiliary and/or engineered safety feature building tunnel temperature was not monitored for a total period of 16 hours and that any condition that would have occurred to elevate area temperatures (fire or line break) could have been detected by other methods. The inspector agreed.

LER 87-50-00 identified that the EQ data logger provided zero degree readings for various components listed on the printout. A non-licensed operator discovered the anomaly. Licensee review disclosed three eight-hour shifts where anomalous data was recorded. The licensee identified the root cause of the event as personnel error since supervisory reviews failed to notice the zero degree readings. The inspector agreed and noted that, even though this review error was similar to the error made on LER 87-06-00, this is not representative because shift supervisors review thousands of log entries each year, with many such errors being detected and corrected during the log review. Personnel have been counseled and procedures have been updated to require a more detailed review. In addition, human factors design review of Datalogger temperature points to improve data retrieval should be completed by June 15, 1988. The adequacy of this action will be reviewed in future inspections.

In summary, the reviewed LERs generated due to EQ related issues fell into two categories: temperature excursions and missed surveillances. Equipment inoperability due to inability to meet environmental qualifications has not been a problem, as is indicated by the lack of LERs in the EQ area. Reportability of EQ related deficiencies is necessary if a system is declared inoperable and, as a result, a plant shutdown is commenced, or if an inoperability would result in a principal safety barrier (50.72 or 50.73) being seriously degraded. Licensee review of the RSS (Recirculation Spray System) pump flow transmitter and Litton-Veam connector reportability hinged on affected system operability; the conclusion was that neither issue was reportable. The inspector concurred with the licensee's RSS reportability determination, as documented in Inspection Report 50-423/88-05. NRC review of the reportability and operability of Litton-Veam connectors used in Millstone 3 is ongoing.

8.0 Maintenance

The inspector observed and reviewed selected portions of preventive and corrective maintenance to verify compliance with regulations, use of administrative and maintenance procedures, compliance with codes and standards, proper QA/QC involvement, use of bypass jumpers and safety tags, personnel protection, and equipment alignment and retest. The following activities were included:

-- Vital battery inspection, dated 5/23/88

-- Service water pump vibration test, dated 5/20/88

-- Control rod drive automatic function repair, dated 5/4/88

No inadequacies were identified.

9.0 Surveillance

The inspector observed portions of surveillance tests to assess performance in accordance with approved procedures and Limiting Conditions of Operation, removal and restoration of equipment, and deficiency review and resolution. The following tests were reviewed:

-- "A" Charging Pump Operational Readiness Test dated 4/13/88

-- Borated Water Source and Flow Path Verification, dated 5/11/88

-- Core Heat Balance, dated 5/18/88

No inadequacies were noted.

10.0 Management Meetings

Periodic meetings were held with station management to discuss inspection findings during the inspection period. A summary of findings was also discussed at the conclusion of the inspection. No proprietary information was covered within the scope of the inspection. No written material was given to the licensee during the inspection period.