U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-423/86-08

Docket No. 50-423

License No. NPF-49

Licensee: Northeast Nuclear Energy Company
P.O. Box 270
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Facility Name: Millstone Nuclear Power Station, Unit 3

Inspection At: Waterford, Connecticut

Inspection Conducted: February 24, 1986-April 14, 1986

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Date

Inspection Summary: Inspection 50-423/86-08, 2/24/86-4/14/86

Areas Inspected: Routine onsite inspection by resident and project inspectors (300 hours). Areas inspected included a number of plant events and non-routine reports and observation of power ascension testing, as well as verification of completion of NUREG 0737 items.

Results: The licensee had several operational events, as documented in Detail 2. No violations or unacceptable conditions were identified. Licensee identified violations associated with a tagged shut Residual Heat Removal System valve (Detail 2.c) and a partial Safety Injection (Dtail 2.f) were found to have received acceptable licensee response.

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1. Summary of Facility Activities

At the beginning of this report period, the plant was in cold shutdown, primarily for flushing the steam generators (SGs) to reduce sulfate concentrations. During that outage (Detail 2.a), approximately 96 valves were repacked, auxiliary steam supply piping to the main air ejectors was replaced, and emergency diesel fuel oil storage tank contents were changed out. The following subsequent activities were noted.

-- 2/28. Plant taken to Mode 4. After temperature soak at 330F, SG sulfates were measured at less than 20 parts per billion (ppb).

-- 2/28. Heatup continued to Mode 3. While raising primary temperature, the P11 interlock reset, per design, at 1985 psia. This caused a safety injection (SI) because SG pressure was below its low pressure setpoint (Detail 2.b(1)).

-- 2/28. A low pressure safety injection valve was found tagged shut when it was required to be open (Detail 2.c).

-- 2/29. Another SI occurred when the Main Steam Isolation (MSI) signal from the earlier SI was reset with the SG atmospheric dump setpoint below main steam pressure. The dump opened and pressure decreased rapidly because the main steam isolation valves (MSIVs) were shut. That caused the SI setpoint to be reached (Detail 2.b(2)).

-- 3/5. Plant was started up to resume testing.

-- 3/7. Power held at 30% while SG blowdown was used to reduce SG sulfates.

-- 3/14. With SG sulfates still above owners group guidelines but no NRC limits exceeded, power was raised to 50% but was reduced 2 hours later due to high pressure drop across the secondary demineralizer.

-- 3/17. Testing resumed at 50% power after demineralizer backwash. The containment access inner door was opened and could not be closed. Access to containment was thereby prevented, but no NRC requirements were exceeded (Detail 2.e).

-- 3/19. A partial SI actuation occurred during protection system testing (Detail 2.f). Later, a Main Feedwater Isolation (MFI) occurred (Detail 2.g) and was followed, a half hour later, by a reactor trip due to low-low SG level (Detail 2.h).

-- 3/21. After removing storm-deposited salt from transformer and switchyard components, the plant was started up (Detail 2.g).

-- 3/24. SG level oscillations prevented going from 50% power to 75%. Corrective adjustments were made to the control system. Calculated core power tilt exceeded limits. Nuclear instrument recalibration corrected

this problem temporarily. [The detector was replaced during a later shutdown when it was found to have been wetted by chromated water.] (Detail 2.i)

-- 3/26. Resumed testing at 75% power (Detail 2.i).

-- 3/29. 50% load reduction test from 75% power satisfactorily performed (Detail 2.i).

-- 3/31. MSIV closure test satisfactorily performed from 20% power (Detail 5.e). Loss of offsite power test initiated from 20% power, with natural circulation satisfactorily established (Detail 5.d). Plant remained shutdown for additional SG flushing, containment air lock door repair, and other maintenance.

-- 4/8. Began startup with post-flush SG sulfate levels of up to 60 ppb (higher than pre-flush levels). FWI occurred due to SG swell when MSIVs were opened with a 40 psi differential pressure across the valves (Detail 2.m).

-- 4/9. Criticality achieved.

-- 4/10. Reactor trip on low-low SG level (Detail 2.n).

-- 4/11. Criticality achieved (Detail 2.n).

-- 4/14. (End of report period.) Plant at 75% power performing neutron detector calibration.

2. Review of Plant Events

a. Unplanned Plant Outage

A normal plant shutdown from 30% power began at 1349, February 21. This outage had not been previously planned and was made to reduce steam generator secondary sulfate concentration. Sulfates were reduced to less than 20 ppb through a series of cold fill and drain evolutions while in Mode 5 (Cold Shutdown). The licensee also corrected other problems identified during startup testing during this one-week maintenance outage.

The licensee has participated in various owner's group activities and has adopted guidelines for secondary chemistry control in procedure CP3802B. That procedure establishes a sampling program and action levels for chemical parameters and impurities throughout the secondary plant. The concentration of a steam generator secondary sulfates is limited to 20 ppb while in excess of 30% power. While holding at that power, it became evident that resin was leaking from the full flow demineralizers into the condensate feedwater system. Resin beads were found in strainers downstream of the demineralizers and sulfate concentrations were observed

to spike to 500 ppb. Because of this, the decision was made to perform a series of cold fill and drain evolutions of each steam generator and to inspect all condensate demineralizer retention elements.

The licensee discovered a wear point caused by a sharp edge on the center fitting of each demineralizer retention element lateral arm. Corrective action included levelling the edges and replacing the damaged nylon retention element filters.

Other maintenance actions during this shutdown included valve packing maintenance on ninety-six (96) primary system valves, repair of a condenser weld, and a modification to the steam jet air ejector steam supply line. Plant evolutions included the replacement of the Emergency Diesel Generator 50/50 diesel fuel/kerosene mix with No. 2 fuel in accordance with vendor recommendations for improving lubrication of diesel fuel system components.

During this period, major portions of the plant were inspected by NRC resident inspectors. These inspections included safeguards equipment areas and the containment. Problems observed were minor and corrected immediately. There were no unacceptable conditions identified.

b. Engineered Safety Features Actuation-Safety Injection (SI)

(1) First SI

A reactor coolant system (RCS) heatup began on February 28, after completion of a seven day outage. The plant entered Mode 3 at 1500. Two engineered safety feature actuations occurred during the approach to normal operating temperature and pressure. The first occurred at 2035 and was due to low steam generator pressure when the P-11 interlock automatically reset on pressurizer pressure increasing above 1985 psia. Although the heatup was conducted within the bounds of the station procedures, the heatup resulted in P-11 being reset when steam generator pressure (560psia) was well below its low pressure setpoint (673 psia). This occurred because the operators were following the leading edge of the heatup curve.

All systems and components performed as required during the safeguards actuation. The safety injection (SI) was reset and safeguards pumps secured within four (4) minutes; approximately 500 gallons were injected by the charging pumps. However, a main steam isolation (MSI) which accompanied the SI was not reset. That isolation has no unique control board annunciator and, at the time of the isolation, the main steam isolation valves (MSIVs) were shut.

Corrective actions on this item are discussed in subparagraph 2.d of this report.

(2) Second SI

A second SI occurred at 0052, March 1, 1986 when a rapidly opening steam line atmospheric dump resulted in a rate compensated main steam line low pressure trip. The atmospheric dump valve was in automatic pressure control with its setpoint below main steam line pressure when operators reset the main steam line isolation (MSI) which had been actuated by the 2035 event.

The operators successfully completed recovery actions without further incident. Corrective actions on this event are discussed in subparagraph 2.d of this report.

c. RHR Injection Isolation Valve found Mispositioned

At 2200 on February 28, with the plant in Mode 3, a Plant Equipment Operator on rounds in the containment found that the Safety Injection Hot Leg Recirculation manual isolation valve to RCS Loop No. 2 was shut with a danger tag attached. The valve had been shut to allow work on an adjacent part of the system and was not restored to its proper, locked open position prior to entering Mode 3 at 1500, February 28.

Upon recovery, the valve was opened. The safety tag log was reviewed for similar errors. Detailed licensee evaluation of this incident concluded that an error in work tracking resulted in failure to identify the need to perform this restoration. The valve which was shut, 3SIL*V932, is required to be locked open in Modes 1, 2 and 3 and provides a flow path to the RCS Loop 2 Hot Leg. The improper positioning would not prevented Cold Leg safety injection.

The work tracking system established for the February 21 outage did not record AW086-4837, which allowed corrective maintenance on valve 3SIL*V937, although the work order was processed and released. Prior to release to the work center (the maintenance department), the operations department shut valve 3SIL*V932 and attached a safety tag. Prior to heat up to Mode 4 on February 28, outstanding work was reviewed. Neither the Production Maintenance Management System (PMMS) nor the safety tag log were reviewed. Both identified an outstanding work order on 3SIL*V937 and an associated safety tag on 3SIL*V932.

This item was identified by the licensee before reactor criticality was achieved during the post-outage startup process. Acceptable corrective actions are discussed in subparagraph 2.d, following.

d. Committee Review of SIs and Shut RHR Valve

The licensee's analysis and long term corrective actions were formulated during meetings of the Plant Operations Review Committee (PORC) on March 1 through 4. The committee reviewed the circumstances concerning the two safety injections and the incorrectly positioned RHR valve. The inspectors observed that the licensee's discussions were thorough and de-

liberate and the corrective actions addressed the weaknesses contributing to those incidents. The actions taken at the direction of PORC prior to plant restart included:

(1) Revisions to Emergency Operating Procedure ES1.1 concerning restoration of systems following an Engineered Safety Feature (ESF) Actuation.

(2) Review of items identified by the Training Department as deviations from the simulator design.

(3) Revision of Heatup Curves to properly clear the P-11 interlock.

(4) Review of the effects on containment equipment qualified life caused by a temperature increase during the ESF Actuations.

(5) Review of restoration of all safety tags back to the last two-person valve lineup.

(6) Review of all safety tags in place on plant equipment.

(7) In plant verification of process flow paths for all safety systems (RSS, QSS, SIH, SIL, CHS).

(8) Briefing of all operating shifts on these incidents.

(9) Providing additional guidance to operating shifts as to the required double checks of valve alignment.

The inspector had no further questions on the above actions. PORC identified several other actions to be taken:

(10) Conformance of the atmospheric steam dump design to the requirements for ESF reset.

(11) Engineering analysis of the need for the main steam line pressure rate circuit.

(12) Addition of an annunciator for Main Steam Line Isolation.

The inspector will follow these additional corrective actions in the course of routine inspections.

e. Containment Air Lock Door Failure

On March 17, the containment personnel access air lock inner door was damaged when it was opened too quickly, impacting its emergency door hinge against the fuel transfer tube wall. The emergency door is approximately 2 feet in diameter, manually operated, and is mounted on the inner door with hinges and shaft on the containment side of the door.

The impact damaged the inner door shaft key and left the door hanging open. Air in the hydraulic door operating system was suspected as the cause of the door opening too quickly.

The emergency door was not operationally inspected for damage on March 17 because it was feared that inability to reshut it would lead to an inoperable inner door. Regardless, the inner door was declared inoperable on March 19 when it could not be shut remotely. It was left open, as evidenced by visual observation through the outer door dead light, until Mode 5 was attained on March 31. The licensee was in compliance with Technical Specifications during this time. The inspectors had no further questions.

f. Partial Safety Injection

At 1PM on March 19, with the plant at 20% reactor power, the licensee was testing the Main Steam Valve Building (MSVB) ventilation damper slave relay in the Solid State Protection System (SSPS). A partial safety injection (SI) occurred when the Train A Emergency Diesel Generator (EDG) sequencer was unexpectedly energized, starting EDG-A and the Train A safety injection and RHR pumps (the Train A charging pump was already running). No water was injected into the Reactor Coolant System. The SI actuation cause appears to be failure to completely document and retest a circuit modification made to the SSPS in January 1986, when the sequencer start signal was changed to the same relay that cycles the MSVB dampers. The problem was further found to be due to failure to change the surveillance to incorporate the results of that design change.

When Millstone 3 was licensed, a number of design changes authorized during construction remained outstanding. On the rationale that the plant design basis included such design changes, the licensee modified the Solid State Protection System (SSPS) circuitry in January 1986 as authorized under a construction Engineering and Design Coordination Report (E&DCR). Implementation was through operations work orders covering alignment, tagout, LCO tracking, and Operations Department authorization of the work. Not using the Plant Design Change Request (PDCR) process bypassed specific provisions for consideration of changes to operating, surveillance, and maintenance procedures; for temporary changes to control room drawings; and for security, radiation protection, ALARA, and fire protection interfaces and planning. It also bypassed Safety Analysis Report requirements for each engineering discipline involved with the design and the Environmental Impact Statement as well as the preparation of an integrated safety analysis.

In this case, the E&DCR involved changed the testing of two valves in the injection flow path. It also repositioned the Sequencer initiation signal to the relay which repositioned the MSVB dampers. That latter

change was not stated in the simple change description provided on the E&DCR and was not brought out during implementation of the design change.

This item was identified by the licensee and reported to the NRC as required. In that the result was partail actuation of a safety system with no adverse affects, the occurrence was not itself safety-significant. All modifications currently planned are to be accomplished via PDCR. Initial licensee review identified no other changes made under the construction change process. Further licensee review is in progress. Pending evaluation of the results of that review, the adequacy of the design change control process is unresolved (50-423/86-08-01).

g. Feedwater Isolation

Between 11 and 12PM on March 19, after reducing power and going off the grid to wash down storm-deposited salt from the transformer and switchyards, the plant experienced a feedwater isolation. The isolation was due to high SG levels while manually controlling SG feed at 10% reactor power. The FWI was reset. Levels were recovered. This event is considered to be associated with development of operator skill in manual SG level control. The inspector had no further questions.

h. Reactor Trip

Thirty minutes after the FWI, operators were shifting from auxiliary feed back to main bypass valve control of SG levels when steam generator B (SG-B) level reached the low-low level reactor trip point. Both trip breakers opened. Plant systems performed as designed. The plant was stabilized in Mode 3. This event is considered to be associated with development of operator skill in shifting SG level control. The inspector had no further questions.

i. Steam Generator Level Control Anamolies

On March 24, while increasing power to 75% for the first time, rapid SG level swings were experienced at 54% power in SG-C and at 58% power in SG-D. Levels in all 4 SGs were soon oscillating. Nuclear Steam Supply System (NSSS) vendor engineers reduced the gain on the level control output to the feed regulating valves (FRVs). Because reduced sensitivity might be masking the problem, power was reduced to 50% and the original level control system gain was restored. The FRVs did not appear to be open as far as expected. A correction was made to modify the FRV differential pressure program to allow the FRVs to open further at lower power levels. This flattened out the level oscillations at power levels slightly above 50%. As power was increased past 56%, levels again began to oscillate. NSSS vendor engineers then raised the gain on the feed pump speed controller and again lowered the gain on the level control system output to the FRVs.

Later, with power level at about 56%, steam flow signals began to oscillate between 56 and 63 percent, causing SG levels to oscillate again. Engineers compensated by lowering the scaling factor in the steam flow/

feed flow error summing amplifier. The plant was then able to attain 75% power and undergo a 50% load reject and a main steam isolation valve closure from 20% power.

SG level control problems have not been eliminated. Further analysis and grooming will be performed during the power ascension program. The inspector will routinely follow this area.

j. Diesel Fuel Oil Spill

While topping off diesel fuel oil storage tanks, the B tank was overflowed into the plant yard at about 2PM on March 25. The oil spill was immediately contained to the asphalt and concrete surfaces of the yard and covered with absorbant material. Approximately 40 to 50 gallons were spilled. Adjacent storm drains were unaffected. Fire hoses were prepared for use. The cause of the spill was an operator not being aware of the rate of level change expected in a tank with a circular cross section. He left the vault for the maintenance area to get absorbant material to clean up oil leaking from some fittings. When he returned, the tank was overflowing. The licensee discussed this event with the operations staff. The inspector had no further questions.

k. Brown Boveri/ITE Breaker Problems

ITE/Brown Boveri type K600S 600V 600A circuit breakers at Millstone Unit 3 have been found to contain a design deficiency which may lead to any or all of the following four conditions:

(1) Failure of the charging motor to charge the breaker closing springs.

(2) Failure of the latch coil to act (loss of remote closing capability).

(3) Loss of electrical trip capability.

(4) Loss of local and remote position indication.

The deficiency is a control wiring harness which is located too close to the racking shaft pawl. The pawl teeth damaged the harness wrap and wire insulation in 8 out of 10 non-safety-related breakers inspected.

Millstone 3 contains 140 such breakers; 41 of these are in safety-related systems. The licensee performed voltage checks on 22 of those which are required to trip during diesel generator sequencer load shedding. No grounds were discovered. The remainder were inspected by the licensee with no deficiencies noted. A night order reminds the operations staff to contact Production Test whenever one of these breakers is racked out. Licensee engineering is designing a relocation of the harness.

The licensee inspected larger K1600 size breakers from the same vendor for harness location problems and found none. K600S and K1600 breakers are the only ones of this type by this vendor at this unit.

The licensee is evaluating generic implications. This issue is unresolved pending completion of that evaluation and verification of acceptability of all safety-related type K600 breakers at Millstone 3 (50-423/86-08-02).

1. Power Range Detector Wetting

During performance of power ascension test appendix 8028, "Incore/Excore Axial Flux Difference Calibration" power range detectors N44 & N42 exhibited plots of top and bottom half core Power Differences over Current (dq/I) significantly different from the other two power range detectors (N43 & N41). At 75% power, the Quadrant Power Tilt Ratio (QPTR) limit of 1.02 was exceeded on detector N42. Recalibration temporarily corrected this problem. During the plant shutdown, the power range detectors were inspected to determine a cause of their anomalous behavior. When continuity checks showed no change from manufacturer's originally tested values, the detector wells were opened for inspection. The well housing detector N44 had 4 feet of standing water and the detector casing was completely flooded. A flooded detector casing could provide the additional neutron moderation that would explain the higher current readings on N44 during performance of Appendix 8028.

The well housing detector N42 had 1 foot of standing water in it. This could explain the QPTR readings obtained at 75% power as well as the dq/I plots obtained. All remaining detector wells were inspected. No further water was found. The water in the wells was analyzed and found to have a potassium chromate concentration similar to that of the neutron shield tank (NST). The licensee therefore performed a pressure test of the NST for 24 hours on April 5 & 6 to determine whether the wells were leaking. There was no measurable increase in water level in the wells. Interviews with the startup engineer responsible for NST testing revealed that the NST had been overflowed through a manway which was directly adjacent to N44 and a short distance away from N42. The manway was not on tightly at the time, and the instrument wells do not have water tight caps. It was concluded that the water had been introduced to the wells during startup testing. The water was subsequently pumped out of the wells and transferred to the radwaste building as toxic and radioactive waste. The chromium 51 activity was measured to be 5X10E-3 mCi/ml.

Detectors N42 and N44 have been replaced. The licensee has modified the power ascension test sequence to calibrate and adjust these new power range detectors in accordance with existing procedures. The inspector had no further questions.

m. Feedwater Isolation

At 9PM on April 8, the unit experienced a Feedwater Isolation (FWI) signal caused by high steam generator levels from swell induced by all 4 Main Steam Isolation Valves (MSIV) opening simultaneously with 40 psi differential pressure. The plant was being heated up in Mode 4 with 40 psi steam pressure. Since the feed system was not operating, the signal had no real effect. Simultaneous MSIV opening was due to control switches being in "Automatic" instead of "Shut" when the motive pressure for valve control was shifted from steam to nitrogen by depressing the cooldown buttons. (The operators needed the MSIVs open to warm up the secondary plant while heating up the RCS). The licensee has committed to revise OP 3316A to insert a precautionary note covering MSIV control switch position when shifting to the cooldown mode. The inspector had no further questions.

n. Reactor Trip

At 2:07pm on April 10, the reactor tripped from 15% power due to low-low steam generator level in SG-C. The reactor operator (RO) was withdrawing control rods to compensate for an RCS temperature drop while bringing the main turbine on line. Steam generator levels were being controlled by the feed regulating bypass valves (FRBP) in automatic. After the initial rod pull, temperature did not turn up as quickly as the RO expected so he continued to pull rods. When temperature did turn up, the rate of increase was high, causing the RO to drive rods in. RCS hot leg temperature reached 570F. Steam generator pressures were up to 1140 psia.

The rod motion sequence set up level oscillations in the steam generators. That led to one level getting to the low-low level trip point. The FRBP valve control circuits compare actual steam generator level to auctioneered high neutron flux to establish valve position. As neutron flux was increasing during the rod withdrawal, the steam generators were being overfed. The feed station operator took manual control and shut the FRBP valves. Level began to drop. The feed station operator could not get control of the level decrease on SG-C and the reactor tripped on low-low level.

The cause of the trip was operator error. The RO was unclear on the response time of the reactor to rod motion at this stage in core life. The inspector will follow licensee corrective actions in this regard as a matter of routine inspection.

Recovery from this reactor trip was hampered by a problem with the Estimated Critical Position (ECP). During the approach to criticality, Group D rods got to 85 steps out without having achieved criticality. At this time in core life, the moderator temperature coefficient is positive for hot zero power with all rods out. Consequently, a restrictive rod withdrawal limit has been established, in accordance with Technical Specification 3.1.1.3.A., to restrict Group D rods to 140 steps or less during

startup. The ECP calculated critical rod height at 28 steps on Group D. The licensee allows a +/-900 PCM (percent milli-rho) tolerance on the ECP value (+/-1000 PCM allowed by Technical Specifications). With Group D currently worth 500 PCM, criticality could be achieved anywhere on Group D and the licensee would be in compliance. When the licensee reached 85 steps withdrawal on Group D without achieving criticality, the startup process was conservatively halted and the controlling rod groups were fully inserted. After adjustment of the boron concentration, the ECP was recalculated, predicting criticality with Group D withdrawn 40 steps. Criticality was achieved with Group D at 67 steps at 3:28 a.m. on April 11. The licensee is investigating the cause of the ECP calculation error. The inspector had no further questions on this item.

3. Review of Plant Operations

The inspector observed plant operations during regular and back shift tours of the following plant areas:

Control Room	Fence Line (Protected Area)
Auxiliary Building	Yard Areas
Diesel Generator Room	Turbine Building
Intake Structure	Vital Switchgear Areas
Main Steam Valve Building	

The tours of the control room included observation of instrument parameters that are necessary for conformance to Technical Specification requirements. The alarm conditions which were in effect and those alarms received at the control room during the period of observation were reviewed. The operators were cognizant of board conditions. Shift manning was in conformance with Technical Specifications, with the shift advisors in place prior to exceeding five percent power. Plant housekeeping controls were observed. Also, during plant tours, the various logs in the Control Room, Chemistry department, and Health Physics department were reviewed to determine if entries were made of events and that records of equipment failures were recorded. In addition, the inspector observed selected actions concerning site security including personnel monitoring, access control and placement of physical barriers. No deficiencies were identified.

4. Security

The inspector observed the security access controls in place at the containment entry point on April 3. Containment entry is made from the Auxiliary Building which also is a Vital Security Area. Based on these observations, station security management was contacted and requested to review the situation at this access point.

The inspector found that the security officer's location in relation to the other work areas at the access point could be improved for greater controls. The original location was away from the computer key card readers, causing all entries to be recorded manually. The single security officer was not

provided with a storage board for security badges collected from personnel entering the containment dressed in radiological protective clothing. The officer was also tasked with calling the Unit 3 operations Shift Supervisor to request entry authorization for any personnel who were entering the containment but not included under a specific Radiation Work Permit.

The security officer was relocated at the access point and was given additional resources to better control the containment access. Matters like calling the Shift Supervisor on matters not relating to security were clarified.

No unacceptable conditions were identified, but security organization performance in identifying this condition could have been improved.

5. Power Ascension Test Witnessing

The inspectors witnessed portions of various Power Ascension Tests performed under procedure INT-8000. Test witnessing included review of the following:

-- Plant Technical Specification requirements were met.

-- Tests were performed using current revisions of approved procedures with all prerequisites and initial conditions met.

-- Briefings were held for all personnel involved; operator actions during test performance were correct, timely and coordinated.

-- Communications were timely and accurate.

-- Supervisory personnel made initial summary analyses to verify plant response was as expected.

-- Preliminary test evaluation was consistent with the inspector's observations.

-- Test acceptance criteria were met.

Results:

a. 10% Load Swing from 75% Power, Appendix 8022

The test was performed at 12:36 on March 29. Power was reduced from 75% to 65% using the turbine load limit potentiometer. SG-A atmospheric dump opened while pressure was below its setpoint (1125 psi). Operators responded by shutting the motor-operated isolation valve. This deficiency is currently under licensee review. All other automatic control systems appeared to function properly. Power was restored to 75% at 12:46PM. The inspector had no questions.

b. Large Load Reduction, Appendix 8026

The purpose of this test was to verify the ability to perform a rapid, 50% load reduction from 75% power. Transient response data was recorded for evaluation of the interaction between control systems and determination of any setpoint changes required to improve response.

The test was performed at 7:05AM on March 30; it was initiated at 75% power by rapidly lowering the turbine load limit potentiometer to the value previously recorded at 25% power. After the test, it was discovered that the final potentiometer setting was actually lower than targeted and the plant underwent a 56% load reduction. All control systems functioned adequately. Three of four steam generator levels got to 25% on the down power transient (the low-low steam generator level reactor trip setpoint is 23.5%). One steam generator level got to 77% when the turbine bypass valves opened (the steam generator high level Feedwater Isolation occurs at 80% level). The inspector had no questions concerning this test.

c. Main Steam Isolation Trip Valve (MSIV) Closure, Appendix 8037

The purpose of this test was to verify MSIV closure times under flow conditions and to verify the ability of the plant to sustain simultaneous closure of all MSIVs from 20% power.

All MSIVs were shut at 10:41AM on March 31. Closure times for each were less that 5 seconds. Plant response was satisfactory. Automatic rod control quickly reduced power. No pressurizer or steam generator safety or relief valves lifted. The inspector had no questions.

d. Loss of Power Test, Appendix 8030

This test was to demonstrate that the plant responds as designed following a reactor trip with no offsite power. The reactor was tripped from about 20% power followed immediately by manual interuption of all normal and reserve offsite power.

The test was initiated at about 4:30PM on March 31. The inspectors observed automatic starts of both Emergency Diesel Generators, functioning of load sequencers, and initiation of natural circulation in the RCS. The turbine-driven auxiliary feedwater pump ran for 2 hours with no compartment ventilation. Licensee technicians monitored pump performance parameters. No problems were identified. Battery operation was forced by removing all AC power to the inverters and chargers. No significant deficiencies were noted.

The licensee identified 22 minor discrepancies during this loss of power test. The inspectors reviewed these items and attended the Plant Operations Review Committee (PORC) meetings when the items were discussed. Adequate corrective action is in progress. The inspectors will continue to follow licensee activities in this area.

6. Carbon Dioxide Fire Suppression System

The Carbon Dioxide fire suppression system has been locked out since it was tested satisfactorily during the preoperational testing phase of plant start-up. The inspector has verified on a sampling basis that the licensee has complied with appropriate Technical Specification action statements by having fire watches posted in safety-related areas while suppression systems have been out of service. The system is currently capable of operation but hazards to personnel safety have prevented the licensee from placing it in operation. A significant amount of modification needs completion before the system is placed in operation. The inspector is monitoring progress with these modifications and it appears they are receiving adequate management attention. The inspector will continue to follow licensee activities in this area on a routine basis.

7. Radioactive Material Transfer

The inspector witnessed the changeout of Charging and Volume Control System (CVCS) letdown filter CHS FLT 2 on April 3. Dose rates were conservatively expected to be in the 80R/HR range, based on surveys on the filter housing. As a result, an elaborate walk through was completed and a full briefing was held for all personnel involved with the changeout and subsequent transfer of the filter to the Unit 1/2 radwaste area. The actual manipulation was completed without incident. Health Physics coverage was excellent. The inspector had minor comments which were discussed with the Health Physics Supervisor. When the Radiation Work Permit was closed out, the final total exposure was calculated to 105 mrem, spread over the entire crew. Of this, 25 mrem came from the filter changeout and transfer out of the Unit 3 Radwaste Building. The remaining 80 mrem was received by personnel moving the radwaste into the Unit 1/2 storage area. The inspector had no further questions.

8. Review of Licensee Event Reports (LERs)

LERs submitted during this report period were reviewed. The inspector assessed LER accuracy, whether further information was required, if there were generic implications, adequacy of corrective actions, and compliance with the reporting requirements of 10CFR 50.73 and Administrative Control Procedure ACP-QA-10.09. Selected corrective actions were checked for thoroughness and implementation.

Those LERs reviewed were:

86-009-00--Feedwater Isolation Actuation-Excessive Feedwater Flow Due to Valve Leakage
86-010-00--Reactor trip on Steam Generator Low Level
86-011-00--Control Building Isolations due to Noise Spikes
86-012-00--Feedwater Isolation due to Main Steam/Feedwater Transient
86-013-00--Feedwater Isolation with Reactor Trip due to Steam Generator Level Transient
86-014-00--Reactor Trip Due to Steam Generator Water Level Transient

86-015-00--Reactor Trip Due to Steam Generator Level
86-017-00--Reactor Trip Due to SSPS General Warning
86-018-00--Feedwater Isolation on Opening "A" Main Steam Isolation Valve
86-019-00--Safety Injection Due to Low Steam Line Pressure
86-020-00--Closed Hot Leg Injection Valve
86-021-00--Safety Injection Due to Low Steam Line Pressure

The inspector had no questions on these LERs.

9. Licensee Action on Previous Inspection Findings

a. (Closed) UNR (50-423/86-02-01)

The licensee has implemented a program for controlling construction work performed on Control Room (CR) and Supplementary Leak Collection and Recovery System (SLCRS) boundaries. In the licensee's Betterment Construction Supervisor letter FLSW-MP3-7654 to the architect/engineer construction superintendent, a check sheet was mandated as an attachment to each Automated Work Order (AWO) effecting CR or SLCRS boundaries. That check sheet clearly identified work being performed to facilitate impact assessment by operations personnel. In addition, the twice daily startup microschedule report provided by the on-shift management representative lists all AWOs that have been released for work on the CR or SLCRS boundaries. The amount of Betterment work will drop off significantly by the time the unit is commercial. Engineering and Construction are currently writing an Administrative Control Procedure to implement this review process administratively. During routine inspection, the inspector will follow licensee performance on this issue as well as compliance with Technical Specification action statements when those pressure boundaries are breached. This item is closed.

b. (Closed) Violation (50-423/85-74-01)

This violation concerns failure to maintain cleanliness and control while safety-related systems were open for constuction/maintenance. The inspector has reviewed the licensee's corrective actions and committments for completion of corrective actions (as described in the letter from J. F. Opeka, Vice President, to E.C. Wenzinger, NRC Projects Branch 3, dated April 2, 1985) and found them adequate. Licensee reinspection after initial corrective actions found no further inadequacies. Resident inspector checks during the four month period after this violation occurred have found no additional instances of this problem. Monitoring of licensee performance in these areas will be ongoing during future inspections. This item is closed.

c. (Closed) Violation (50-423-85-74-02)

This violation concerns failure to restore system line-up to normal. The inspector has reviewed the licensee's corrective actions (as described in the letter from J.F. Opeka, Vice President, to E.C. Wenzinger,

Chief, NRC Projects Branch 3, dated April 2, 1985) and found them adequate. The individuals involved were reinstructed. All operators were made aware of this matter. The resident inspector found the licensee's corrective actions to be aggressive and acceptable. This item is closed.

10. Licensee Actions on TMI Task Action Plan (TAP) Requirements specified in NUREG 0737

The NRR Staff has reviewed the licensee's submittals addressing the NUREG 0737 items and has documented their evaluations in NUREG 1031, the Safety Evaluation Report (SER) including five supplements (SSER-1 through 5). During this inspection, a region-based inspector verified the following conditions related to the subject items.

a. I.C.1.3B (85-TM-29) Additional Review by Licensee of Accident Procedures (Closed)

In IR 50-423/86-02, this item was left open pending further information on three-loop operation to be provided to NRR by the licensee. The conclusion of SER Section 13.5.2.3, "Reanalysis of Transients and Accidents; Development of Emergency Operation Procedures," is that resolution of the staff's (NRR's) longer term requirement for improvements to loop isolation guidance for N-1 loop operation must be provided before the staff approves N-1 loop operation. License Condition 2.C.(4) prohibits N-1 loop operation. Therefore, the open part of this issue will be reviewed and resolved prior to approval of three loop operation. TAP Item I.C.1.3B is closed based on license condition coverage of this issue.

b. I.C.8 (85-TM-30) Pilot Monitoring of Selected EOPs for NTOL Plants (Closed)

SER Section 13.5.2.3 states that TAP Item I.C.8 is no longer necessary as a result of NRC approval of the Westinghouse Emergency Responce Guidlines (ERGs) and the applicant's commitment to develop the EOPs based on the ERGs. Those EOPs have been implemented by the licensee and were used by the operators during the operator licensing process with no unacceptable conditions identified. This item is closed.

c. II.B.1 (85-TM-31) Reactor Coolant System Vents (Closed)

In SER Section 15.9.1, NRR concluded that the RCS vent piping and equipment in the flow path is acceptable. Inspection Report 50-423/85-69, Page 5 and 6, documents an inspector's witnessing of the reactor head vent operation retest following correction of a wiring problem. On this bases, NUREG Item II.B.1.2, the installation of the vents, is closed.

To confirm Subpart II.B.1.3, procedures for the use of RCS vents were reviewed by the inspector. The specific procedures reviewed were:

-- EOP 35 F-0.6 Inventory-Critical Safety Function Status Tree; and

-- EOP 35 FR-I.3 Response to Voids in the Reactor Vessel.

EOP 35 F-0.6 is a status tree produced by the SPDS computer, backed up by hard copy. For this condition, SI unavailability and results in the reactor vessel level monitoring system (RVLMS) indicating that the upper head level is less that 100 percent. The operator is referenced to EOP 35 FR-1.3. That procedure leads to venting the reactor head. The inspector found the subject EOPs acceptable; thus TAP Item II.B.1.3 is closed.

d. II.B.2.3 (85-TM-33) Plant Shielding Modifications (Closed)

The shielding design for Millstone 3, per SER Section 12.3.2, was received, updated, and modified during plant design and construction to incorporate the features of Reg. Guides 1.69 and 8.8. The SER left a confirmatory item that involved licensee submittal and NRR review of a radiation and shielding design review package. SSER-1, Section 12.3.2 documented the acceptability of the radiation and shielding review for vital area access.

The inspector's review of the SER and SSER-1 and discussions with the licensee confirmed that no modifications have been made to shielding systems since approval of the plant's design and construction based on that design. Sampling checks of this TMI item by the former Millstone 3 senior resident inspector have been performed by checking as-built conditions against the TMI item, with no discrepancies identified. TAP Item II.B.2.3 is closed.

e. II.E.1.1 Short and Long Term Auxiliary Feedwater Modifications (Closed)

The AFW System is evaluated in Section 10.4.9 of the SER and a single open item is resolved in SSER-1, Section 10.4.9. NRR concluded that the Millstone-3 AFWS original design and construction meets the acceptance criteria. The licensee has made or is making two minor modifications to the design. First, a level glass has been added in the turbine driven AFW pump cubicle to indicate the demineralized water storage tank (DWST) water inventory is below the existing tap level. This modification, performed under Work Order M3-85-38116, has been made to meet Regulatory Guide 1.105. It allows the operator to valve in the in-service pump suction line and locally determine DWST level. The second modification, being made under PDCR #MP3-86-030, will be to make a temporary alternate source of makeup water for the DWST a permanent change. This change was with licensee Engineering at the time of inspection. No other modifications were made from the design as accepted by NRR.

The inspector reviewed the test record for the 48 hour endurance run on the electric AFW pumps, the latest SR showing the electric pump response times of 4 seconds for the A pump and 2.6 seconds for the B pump (TS

require ≤ 60 sec.), the current temporary provisions (manual draining steam lines every 4 hours) to prevent water hammer and physically observed startup and operation of the turbine-driven AFWS pump. During this operation, the inspector observed that the auxiliary operator had no procedure to follow although he was in direct communication with the control room through a sound-powered head set. In later discussions with shift management, it was learned that the auxiliary operator had been pulled from other work to follow the turbine-driven AFWS pump operation and the procedural steps were being read to him from the control room. This is a less that desireable method of operation, but does not violate plant procedures or NRC requirements.

Based on the review of the SER evaluations and on the physical observations, TAP Item II.E.1.1 is closed.

f. II.E.3.1.1 (85-TM-35) Emergency Power Supply for Pressurizer Heaters (Closed)

This issue was evaluated and found acceptable in the SER, Sections 8.3.3.4, 8.3.3.3.12, 8.3.3.3.16, 7.2.2.1 and SSER-1, Section 7.2.2.1. TS 3.43 requires the operability of at least two groups of pressurizer heaters supplied by emergency power with each group having a capacity of at least 175KW. The FSAR documents that one bank of pressurizer backup heaters in sufficient to maintain natural circulation following a loss of offsite power.

The inspector reviewed Surveillance Requirements 4.4.3.2 records to confirm two groups of heaters had over 175 KW of heating capacity; SP 3712B, performed on 1/4/86, found Group A had 323.6 KW and Group B had 320.4 KW. The inspector confirmed that Groups A and B are supplied from emergency diesel generator powered busses. TAP Item II.E.3.1.1. is closed.

g. II.E.4.2.1-4 Diverse Containment Isolation (Closed)

This requirement was to have diversity in the parameters sensed for the initiation of containment isolation. The Millstone 3 containment isolation CIA signal (which isolates non-essential systems on high containment pressure of 1.5 psig, low compensated steamline pressure, pressurizer low pressure, or manually) and CIB signal (isolating reactor plant component cooling water lines and opening containment isolation valves for the depressurization system on high containment pressure of 10.0 psig or by manual actuation) were found to have adequate diversity in Section 6.2.4 of the SER.

The inspector reviewed TS Table 3.3-4 and found the CIA and CIB trip setpoints required were ≤ 3.0 psig and ≤ 8.0 psig, respectively. The

CIA trip setpoint difference (1.5 psig assumed in the SER verses ≤ 3 in the FSAR and TS) is due to incomplete setpoint calculations at the time the SER was issued.

Surveillance records show that the instrumentation is correctly set and trip channel operation has been confirmed. TAP Item II.E.4.2.1-4 is closed.

h. II.E.4.2.5B Diverse Containment Isolation (Closed)

After NUREG 0737 was issued in 1980, the requirements for containment isolation that resulted in modifications at completed plants were included in the design and construction of Millstone 3. No modifications beyond those in the FSAR, as amended, were identified. The inspector confirmed that the design incorporated the diverse containment isolation features to which the licensee committed and which NRR accepted. This item is closed.

i. II.E.4.2.6 Containment Purge Valves (Closed)

SSER-2, Section 6.2.4 provides an evaluation of the operablility of containment purge and vent valves. The licensee has committed to and is required by TS 3.6.1.7 to maintain the 42-inch purge supply and exhaust isolation valves locked closed in Modes 1,2,3 and 4.

The inspector confirmed that the containment purge valves were verified closed at least once per 31 days in accordance with TS 4.6.1.7.1 and that the TS 4.6.1.7.2 pressurization leak test had been completed on time. TAP Item II.E.4.2.6 is closed.

j. II.E.4.2.7 Purge Valve Radiation Signal (Closed)

The licensee has installed a two channel radiation monitoring system to monitor the containment area and cause a purge and exhaust valve isolation under accident conditions. This system is used to mitigate the consequences of the fuel handling accident inside containment evaluated in SER Section 15.7.4. This SER evaluation, based on valve closure within 2.5 seconds following a fuel handling accident and assuming a 5 second delay for radioactivity to reach the purge system under normal conditions, concludes that the same accident in the fuel pool area is limiting. Therefore, no dose values were calculated.

Amendment 17 to the FSAR changes the purge valve closure time to less than 3 seconds and states that the response time of the radiation monitors is less that 2 seconds. The less-than-3-second closure time is required by TS Table 3.6.-2; the ≤ 1 R/hr setpoint and the LCO is found in TS Table 3.3-6 and Specification 3.3.3.1.

The inspector reviewed surveillance procedures confirming that valve operablility was less than the required 3 seconds. The inspector observed operation of the Radiation Monitoring System (RMS) computer and

noted that the alert and high level isolation setpoints for the purge valve isolation monitor channels were set at 100 mr/hr and 920 mr/hr, respectively. The inspector also reviewed the physical locations of the monitors and the exhaust isolation valves. These have good separation such that the accident would be detected and the exhaust valves closed quickly with minimal release. This agrees with the FSAR analysis and the SER evaluation. TAP Item II.E.4.2.7 is closed.

k. II.F.2.1 Inadequate Core Cooling (ICC) Procedures (Closed)

Procedures for ICC are entered from OPS Form EOP 35 F-0.2 which uses Safety Parameter Display Systems (SPDS) information such as core exit thermocouple, subcooling margin, and reactor vessel level measuring system readings to guide the operator to the correct EOP. The end point EOPs are:

Red-FR-C.1, Response to Inadequate Core Cooling;
Orange-FR-C.2, Response to Degraded Core Cooling; and
Yellow-FR-C.3, Response to Saturated Core Conditions

The inspector reviewed Revision 1 of the above EOPs and found the caution statements, the system groupings, the two columns for action/expected response and response not obtained, and the go to step X instructions easy to understand. These EOPs are based on Westinghouse generic guidelines approved by NRR. Discussions with the plant staff indicate good acceptance of these EOPs. The inspector concluded that the ICC EOPs are adequate, realizing that refinements may be made as experience is gained. This TAP item is closed.

l. II.F.2.2 Subcooling Margin Monitor (Closed)

The installed subcooling margin monitor uses RCS temperatures and pressures to calculate subcooling and superheat either in terms of temperature or pressure. SSER-5, Section 4.4.8.3 documents NRR's evaluation and acceptance of the design.

The inspector observed the SPDS computer output displays showing subcooling at the 50 locations where the core exit thermocouples are situated. The computer monitoring program is set to automatically display, alarm and flash for 10 seconds, and then remain steady if abnormal subcooling margin exists. This system is user friendly and has been installed to meet the SER evaluation criteria. This TAP item is closed.

m. II.F.2.4 Install Additional Inadequate Core Cooling (ICC) Instrumentation (Closed)

The additional ICC instrumentation installed at Millstone 3 are the core exit thermocouple (CET) monitoring system and the heated junction thermocouple (HJT) reactor vessel level monitoring system. The CET consists of two redundant independent trains that monitor the 50 chromel-alumel

CETs; the temperature range is 200-2300F. The HJT system includes two channels, each consisting of a string of eight sensors, indicating percent level in the plenum and head areas. SER Sections 4.4.8.4 through 4.4.8.6 find the CET and HJT acceptable to satisfy TAP II.F.2.4.

The inspector observed the SPDS computer outputs for CET and HJT information. The CET data can be seen as outlet temperature or subcooling readings at each of the 50 locations. At the time of the inspection, three of the points were out of service, but the overall system was operable. The HJT data is shown as unheated thermocouple temperature and as level at head locations of 100 and 63 percent and upper plenium locations of 100, 82, 64, 47, 32, and 19 percent. This data may be requested from multiple CRTs in the control room and the emergency support centers. This additional ICC instrumentation was operational in accordance with the SER evaluations. This TAP item is closed.

n. <u>II.K.3.9 Proportional Integral Derivative (PID) Controller Modification (Closed)</u>

This issue was addressed in the SER, Section II.K.3.9. Westinghouse has recommended that the derivative time constant in the pressurizer PORV PID controller be set to "off" to correct this problem. The staff found this correction meets the guidelines for TAP Item II.K.3.9.

The inspector confirmed that the derivative time constant in the PID controller has been set to zero; this turns the derivative function off making the controller function like a PI controller. However, during a recent test with the reactor on natural circulation, an approximate 15 psi delta pressure above the normal 2250 psia for about one-half hour caused PORV PCV 455A to open. This was due to the integrating circuit. The licensee is investigating resolution of this issue under Deficiency UNS 7578. The inspector concluded that it is also possible for the PI controller to keep the PORV closed if the pressurizer pressure is below 2250 psia for a relatively short time prior to a condition when PORV opening is desirable. These issues will remain an unresolved item pending licensee resolution and follow-up inspection (50-423/86-08-03). However, TAP Item II.K.3.9 has been fulfilled and is closed.

o. <u>III.D.1.1.1 Reduced RCS Leakage Outside Containment (Closed)</u>

This NUREG 0737 item was evaluated in SER and SSER-4, Section 15.9.15 and found acceptable. TS 6.8.4 requires a leakage reduction program for the portions of the recirculation spray, safety injection, charging portion of chemical and volume control, and hydrogen recombiner systems. The licensee describe[illegible] design features implemented to minimize and to monitor any radioa[illegible] leases in a letter dated October 1, 1985. In addition, they desc[illegible] procedures that will implement the TS required program. The [illegible]ogram will be very similar to that implemented at Millstone 2. Since [illegible]ction of the leakage reduction program procedures is a normal insp[illegible]on item that will be performed at a later date, TAP Item III.D.1.1[illegible]s closed.

p. II.K.3.1, PORV Isolation; II.K.3.5, Automatic Reactor Coolant Pump Trip; II.K.3.10, Anticipatory High Power Trip; II.K.3.12, Confirmatory and Anticipatory Trips; and II.K.3.25, Pump Seals (85-TM-37) (Closed)

The inspector confirmed that no modification had been performed since the approval of the system design and construction as evaluated by the SER and the SSERs. The inspector confirmed that these features were incorporated in the design in accordance with the SER. These five TAP items are therefore closed.

11. Management Meetings

At periodic intervals during the course of this inspection, meetings were held with senior plant management to discuss the scope and findings of this inspection. No proprietary information was identified as being in the inspection coverage. At no time during the inspection was written material provided to the licensee by the inspector.