U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-423/89-04

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: April 5 - May 15, 1989

Reporting Inspector: W. J. Raymond, Senior Resident Inspector

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

Approved by: Eric C McCabe, Jr 6/28/89
E. C. McCabe, Chief, Reactor Projects Section 1B Date

Inspection Summary: Inspection on 4/5/89 - 5/15/89

Areas Inspected: Routine onsite inspection (112 hours) of plant operations, previous inspection findings, Plant Incident Reports, reactor scrams on May 6 and May 11, a shutdown to repair high unidentified leakage on April 11, physical security, repairs to service water piping, allegations and the MAP 4.16 Allegations Resolution Program, Rosemount transmitters, maintenance, and surveillance.

Results: No violations were identified. Reviews of plant operational status during operations and during the refueling shutdown identified no unsafe conditions. Further NRC review is warranted on whether additional licensee documentation of their program for temporary repairs to code class piping is required to NRR (Detail 7.0). Rosemount transmitter failures due to oil loss were found to be adequately addressed; additional information will be needed to follow the licensee's actions on this matter.

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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 Superintendent, Unit 3
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 began the inspection period at full power and operated until 7:20 a.m., April 8 when a power reduction to 90% was necessary to perform condenser thermal backwashes. Power was returned to 100% by 6:55 p.m. that day.

A power reduction was commenced at 11:45 p.m. April 11 when unidentified leakage (See Detail 5.0) increased from 0.5 gpm to 2.5 gpm. The leak was confirmed by increases in containment radiation levels and chemistry samples. The leak was from a cracked weld at a letdown line valve. A plant shutdown was completed at 10:00 a.m., April 11 and cooldown was complete at 10:48 p.m., April 12. A new valve was welded in place and establishment of containment vacuum began at 3:05 p.m., April 14. Heatup began with Mode 3 being reached at 10:48 p.m. April 14. Reactor startup began with criticality occurring at 2:11 p.m., April 15. Full power was achieved at 8:38 p.m., April 17.

The plant continued to operate at full power until 8:10 a.m., May 6 when a manual reactor/turbine trip (Detail 6.1) was initiated due to the loss of two circulating water pumps due to seaweed blockage on the intake screens. The storm subsided and the reactor was started up and made critical at 10:39 p.m., May 6. The plant returned to full power operations.

The reactor automatically tripped on high negative flux rate from full power at 3:14 p.m. on May 11 (Detail 6.2). The trip occurred as I&C personnel were installing test equipment in preparation for control rod scram time testing. The plant was kept shutdown to begin the refueling outage.

Refueling Outage #2 is scheduled to last 52 days and will include the following major activities: installation of the ATWS mitigation system; service water system inspection and repairs; ISI weld inspections; refueling; installation of reactor vessel level monitoring system for mid-loop operations; and, a containment integrated leak rate test.

3.0 Status of Previous Inspection Findings (92701)

3.1 (Closed) IFI 85-09-01, Inspector Findings Regarding the Modified/Amended Security Plan

The inspector reviewed the results of inspection 50-423/85-64 and noted that the inspection reviewed whether the Millstone 3 Physical Protection Program, including personnel, equipment, systems and facilities, was being effectively integrated into the proposed combined security program for the Millstone site. The review also included a special evaluation of the security force training program to determine the ability of security force personnel to carry out their duties and responsibilities by observing licensee administered examinations of a statistically selected sample of security force personnel, in the tasks in which they were qualified, to obtain results at a confidence level of 95%. Additionally, the review included interviews of key members of the security organization and project engineering staff responsible for the installation and testing of security systems and equipment. The review indicated that the Unit 3 security program conformed to NRC requirements in the areas examined and was being effectively integrated into the Millstone site program.

In addition, recent reviews and inspection have concluded that the Millstone 3 Modified Amended security plan was adequately integrated into site security. Any violations and/or deviations have been addressed and effective corrective action was noted. Based on the licensee performance to date, this item is closed.

3.2 (Closed) UNR 87-24-01, Issue Amendment to Allow Testing of Containment Overcurrent Devices to NEMA Criteria

Amendment 13, dated January 20, 1988, was issued to revise the instantaneous overcurrent trip setting from plus or minus 20% to plus 40% minus 25% per the NEMP AB-2 criteria. Past testing conformed to the expanded tolerance. This item is closed.

3.3 (Closed) IFI 85-56-02, Review Solid Radwaste System and FSAR Amendment Reflecting As-Built Design

FSAR Section 11.4.1 was revised in 1987 to reflect changes in the waste solidification design. This revision replaced the in-site system with mobile solidification equipment. Existing system connections are compatible with the mobile solidification equipment. This item is closed.

3.4 (Closed) IFI 85-56-03, Review Dewatering Procedure and Fill-Head Venting Modifications

OM-43 replaces the OM-38 regarding operation of the NuPac Resin Drying/Dewatering System. Procedure OM-43 contains the necessary instructions and emergency actions relative to system alarms. In addition, the procedure requires an operational check of the system interlocks prior to initiating a resin transfer. Also, the exhaust from the resin drying equipment is discharged through a HEPA ventilation unit. Therefore, the plant's vent system would not be required to handle any contaminated exhaust ventilation from the equipment. These procedure changes were responsive to the inspector's concerns. This item is closed.

3.5 (Closed) IFI 85-56-04, Review Radwaste Procedures for Reference to New Dewatering and Solidification Processes

OP 3338A, Radioactive Solid Waste and OM-43, NuPac Dewatering System describe the proper operation of their respective systems. In the event that waste solidification is necessary, a vendor's Process Control Program will be reviewed and SORC approved in order to accomplish the solidification. The solidification will be done with a mobile solidification system provided by a vendor. This activity is routinely inspected by the core inspection program. Future deficiencies noted will be addressed by the licensee during these inspections. This item is closed.

4.0 Plant Operational Status Reviews (71707)

The inspector reviewed plant operations from the control room and reviewed the operational status of plant safety systems. Actions taken to meet technical specification requirements when equipment was inoperable were reviewed to verify the limiting conditions for operations were met.

Plant logs and control room indicators were reviewed to identify changes in plant operational status since the last review and to verify that changes in the status of plant equipment was 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 to verify proper response to off-normal conditions and to verify operators were knowledgeable 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.

5.0 Excessive Unidentified RCS Leakage (93702)

At 11:45 p.m., April 11, with the plant at full power, a shutdown commenced when RCS unidentified leak rate reached 1.5 gpm (Technical Specification (TS) limit is 1.0 gpm). The leakage was caused during Engineered Safety Features (ESF) slave relay surveillance testing earlier in the day (4:00 p.m. to 6:00 p.m.). The RWST suction valves to the charging pumps were being opened for the test when operators closed down on the charging flow control valve to limit the amount of 2300 ppm boron that was injected to the RCS. The charging flow reduction was necessary to limit the post surveillance dilution required to return boron concentration to its end of cycle concentration. Charging flow was reduced rapidly, causing a decrease in heat transfer across the regenerative heat exchanger. This action caused flashing to occur downstream of the letdown orifices due to higher inlet temperatures. The subsequent manual increase in charging flow collapsed this bubble causing a water hammer to lift and reseat the letdown relief valve. An unidentified leak began at this point.

The increase in leak rate manifested itself to the operator between 8:00 p.m. and 10:00 p.m. as increases were noted in containment radiation levels and sump pump rates. The shift supervisor ordered the sump sampled for boron and activity. The sample boron concentration and activity was reported back at 11:30 p.m. representative of RCS liquid, confirming the leak indications. An Unusual Event was declared at 11:48 p.m. April 11 and the NRC was notified via the ENS at 12:07 a m., April 12. A power decrease was conducted to reduce inside containment radiation levels in preparation for containment entry. The entry team received their medical exam and was briefed on potential leak locations. The containment entry team located the leak on a cracked weld on a leakage monitoring valve (3CHS*V995) letdown line at 3:20 a.m., April 12. The weld connected the valve body to a 3/4 inch vent line. Spray was observed in a 270 degree arc coming from the weld. The leak is isolable by the inboard containment isolation valve and the orifice isolation valves. Leak repair required cold shutdown. Reactor shutdown was completed at 9:11 a.m., April 12 and the licensee continued plant cooldown to effect repairs. The leak was isolated during the cooldown, after Residual Heat Removal (RHR) cooling was initiated. The Unusual Event was terminated at 8:05 p.m., April 12.

The inspector reviewed licensee actions during this event. Licensee actions were generally effective and showed due regard for safety. Technical Specification time limits were met. The plant was cooled down without incident.

The inspector questioned the need for the sump activity and boron sample to confirm the leak. The licensee had two supporting indications (containment radiation levels and sump pump rates) that confirmed the initial leak rate. Sampling the sump resulted in an unnecessary delay in plant shutdown. Licensee use of real time supporting indications for offnormal conditions will be reviewed in future inspections.

Licensee use of the RCS leakage abnormal operating procedure (AOP) was lacking. Neither the swing shift or midnight shift shift supervisor (SS) used the AOP. They felt it was unnecessary since they knew what they wanted to do. The inspector emphasized the need to follow procedures and emphasized that operators receive the wisdom of all the members of Plant Operations Review Committee when they use and follow procedures. Procedural adherence during off normal conditions will be reviewed during future inspections. This item will remain unresolved pending further NRC review of licensee procedural use and adherence (UNR 89-04-01).

6.0 Followup of Plant Trips (93702)

6.1 Reactor/Turbine Trip due to Low Condenser Vacuum

On May 6, at 8:10 a.m., while at 90% power, a manual reactor/turbine trip was initiated due to lowering main condenser vacuum. Power had previously been lowered to complete a condenser backflush. The "A" and "B" main circulating water (CW) pumps had been automatically tripped at 8:08 and 8:09 a.m., respectively due to high suction differential pressure (DP). The high DP condition was the result of an early morning storm. Excessive blockage on the intake screens resulted in the inability of the screenwash system to continue to clean the screens. The loss of both CW pumps on high DP resulted in a low vacuum in the "C" condenser shell which forced the manual reactor trip. All safety systems responded appropriately to the trip. Operators stabilized the plant in hot shutdown. The trip was reported in accordance with 10 CFR 50.72(b)(2)ii at 8:30 a.m., May 6.

The intake screens were cleaned subsequent to the trip and the plant was restarted after the stormy conditions subsided. The approach to criticality was initially begun at 1:00 p.m., but was aborted when the 1/M plot showed that criticality was predicted beyond the capabilities of control bank D. The licensee had anticipated that rod worth could overcome the effects of Xenon buildup after the trip. The ECP was recalculated for later that evening with the approach to criticality commencing at 9:58 p.m., May 6. The reactor was made critical and Mode 1 was entered at 12:38 a.m., May 7.

The inspector reviewed the sequence-of-events printout and the operator questionnaires. Items of minor significance were questioned and satisfactorily addressed by the licensee. No inadequacies were noted.

6.2 Reactor/Turbine Trip due to Control Rod Testing

The reactor scrammed automatically on negative flux rate trip from 100% full power at 3:14 p.m. on 5/11. The scram occurred when I&C personnel turned off a "rod drop monitor computer" which caused

control rods to insert. The rod test equipment was set up in preparation for scram time testing scheduled during the plant shutdown for the refueling outage on May 12.

Operators stabilized the plant in hot shutdown at 560F and 2250 psig. Plant response to the transient was normal except for minor problems with a sticky pressurizer spray valve; problems re-opening the main feedwater control valve to the A steam generator in the post-trip recovery phase; and problems with the auxiliary feedwater flow control valve to the D steam generator.

The steam driven auxiliary feedwater pump was out of service for overspeed testing at the time of the trip; a 72 hour action statement per TS 3.7.1.2 was in effect. Steam generator level control was maintained with main feedwater system and the two motor driven auxiliary feedwater pumps as required. No ESF systems were required to operate. The resident inspector responded to the control room and verified stable plant conditions. Inspector review of main control board indications verified the plant responded as expected (except as noted above) for a reactor/turbine trip, and that reactor operator responses were proper. No inadequacies were noted.

The licensee reported the scram to the NRC Duty Officer as required by 10 CFR 50.72(b)(2)(ii) at 3:39 p.m. May 11. The licensee kept the plant shutdown to begin the refueling outage since fuel exposure was within the required burnup window.

The negative rate trip occurred when two or more control rods inserted while I&C technicians were installing the control rod timing computer. I&C personnel had entered the containment to install the equipment and test the communication links between the remote rod position signal units and the computer. The communication link tested satisfactory per procedure SP 345IN21. The technician also connected the computer to the control rod logic cabinets (3RDS-RHK1HC) per the same procedure. The trip occurred as the technician powered down the computer. This action caused a spurious signal in the logic cabinet that resulted in rod insertion. This same test set up had apparently been performed in the past without incident. The exact mechanism on how the text equipment caused the rod insertion was still under licensee investigation at the end of the inspection period.

Licensee review of equipment performance following the trip noted the following:

(i) A misaligned limit switch on main feedwater isolation valve FWS*CTV41A for the 'A' steam generator prevented re-opening the valve on demand by the reactor operator following the scram. The misaligned NAMCO switch failed to indicate the valve was "closed" and prevented satisfying the reset permissive in the valve isolation circuit (reference S&W Drawing ESK-7JN). The

valve was opened by the operators with the assistance of maintenance personnel at 4:52 p.m. Licensee corrective actions included plans to review switch mounting on other valves and to improve the switch mounting bolt arrangement.

(ii) Following the scram, the auxiliary feedwater flow control valve (FWA*FCV31D1) to the 'D' steam generator closed in response to demand by the reactor operator to control level and prevent excessive cooldown rates. The valve failed to reopen and generator level was controlled using main feedwater. Licensee review determined that the valve controller failed on the main control board when a drive cord broke between the thumbwheel and the potentiometer that provides the position demand signal. Corrective actions included review of actions necessary to periodically inspect the cords on other controllers.

(iii) Following the scram, the reactor operator noted reactor coolant system pressure decreased to about 2000 psig due to inadvertent operation of pressurizer spray valve RCS PK 455B. Operator action to place the controller in manual to cycle the valve, and operation of the pressurizer heaters limited the RCS pressure decrease. The valve controller on the main board was trouble reported on 10/31/88 due to suspected problems with the controller "sticking" sometimes. The loop 2 cold leg pressurizer spray valve, RCS PK 455C, had been out of service since 2/25/89 due to a controller problem. Licensee corrective actions included replacement of both controllers during the refueling outage.

Inspection of the event included interviews with operators and management personnel, review of control room indications, and a review of the sequence-of-events printout, post trip data available from the plant computer, and the licensee's post-trip documentation (PIR 66-89, EPIP 4112-3 and OPS Form 3263). No anomalies were noted in plant system performance. Licensee review and evaluation of the event was proper. No inadequacies were identified.

The resident inspector will follow the licensee root cause evaluations, equipment repairs, LER summary and corrective actions on a subsequent routine inspection. No inadequacies were identified.

7.0 Non-Code Repairs to Code Class Systems (71707)

NRC Inspection Report 88-24 describes previous NRC review of licensee actions to identify and correct leaks in ASME Code Class 3 piping in the service water system. Previous inspections found licensee evaluations of known leaks were technically acceptable to assure piping system integrity during interim periods of operation. The licensee used temporary repairs to limit the leakage from the system until the plant shuts down for an outage.

Service Water Leaks

One problem reviewed previously and addressed again during this inspection period, concerned a leak in the service water outlet from the "A" reactor plant component cooling water (RPCCW) heat exchanger, just down stream of valve 3SWP-V35. A through wall defect in the copper-nickle clad, carbon steel pipe was found to be highly localized and had dimensions that were less than the critical size that would jeopardize structural integrity of the 18 inch diameter pipe. The licensee installed a leak limiting device (a "soft-patch" - wood plug held in place by metal and or webbed bands) to reduce water spillage to the floor area. The licensee removed the "A" RPCCW heat exchange from service on April 18 to further evaluate the defect after noting leakage had increased to about 5 to 10 gpm on April 17. Further licensee investigation found that although the size of the defect had increased slightly, the conclusions from the prior technical indication remained valid. Actions were taken to reduce the leakage by improving the patch and then returning the system to service. The inspector reviewed the technical evaluation with engineering personnel and identified no inadequacies.

License Requirements

Further inspector review on April 18-19 of the regulatory requirements for construction, inspection and repair of safety class piping raised a question whether the plant was operating within the licensing basis for the interim period of operation under a "temporary repair" (soft patch). The ASME code of reference for MP3 specified in 10 CFR 50.55a(g)(3)(ii) is ASME III and ASME Section XI. Final Safety Analysis Report Table 3.2-1 establishes the correlation between ASME code classification and safety classification for piping systems, and classifies the RBCCW and Service Water Systems as Safety Class 3. Technical Specification 3.7.3 provides the operability requirements for the RBC CW system. Technical Specifications 4.0.3 and 4.0.5 requires that safety class systems be tested per ASME Section XI and further states that failure to meet the TS surveillance requirements constitutes a failure to meet the limiting condition for operation.

Section IWD 2600 and Table IWD 2500-1 of ASME Section VI applies to safety class 3 piping systems. The code requires that safety class 3 piping be subjected to periodic visual examination with an acceptance standard that no leakage is permitted in the pressure retaining boundary. The ASME Section XI code recognizes approved repair methods for code class piping, but does not recognize temporary repairs or "soft patches." The use of repair methods on code class piping that is not recognized by the ASME Code constitutes a condition contrary to the requirements of 10 CFR 50.55(a)(g) that is outside the NRR approved licensing basis for the plant.

Safety Significance

This matter was discussed with licensee technical staff and management on April 19 and during a conference call between licensee and NRC Region and NRR staff on April 20, 1989. The licensee further described his program to monitor and address degradation in both small- and large-bore piping in the service water system in a letter dated April 28, 1989. The licensee stated that the soft patches are not ASME code repairs, but are interim non-weld repairs intended to be used until an outage of sufficient duration occurs to allow permanent code repairs. The licensee's engineering evaluations assured structural integrity criteria of the ASME code was not met even with the defects, and that operability of equipment in the area of the leak would not be compromised by flooding, assuming no credit is taken for the soft patch. The interim repair is considered a maintenance activity that limits the amount of water leakage from the piping. NRC staff review of the licensee's position identified no inadequacies with the technical evaluations or the program to address service water system leaks. Based on the above, the inspector identified no safety concerns regarding continued plant operation with temporary repairs on safety class 3 systems.

This matter requires further review by NRC management to determine what further actions, if any, are required by the licensee. An NRC staff position to address this issue generically for the industry is pending. This item is unresolved pending completion of the review by the NRC (UNR 89-04-02).

8.0 Followup on Rosemount 1153 and 1154 Transmitters (92700)

Problem Summary

The inspector reviewed ongoing licensee actions to address suspect Rosemount transmitters. The inspection review included a meeting with corporate engineering personnel on March 30 and a meeting between NRC technical staff in headquarters with industry groups on April 13, 1989. The licensee updated his initial 10 CFR Part 21 report by providing supplemental information in a letter dated April 13, 1989.

The inspection reviews, along with input on April 3 from a licensee employee with safety concerns about the issue, identified new information to the NRC about the number of failures, the failure mode, the relatively high failure probability, and the significance of having a failed instrument that was not detectable. The employee's safety concerns involved addressal of the issue at other nuclear plants since actions to address the issue at Millstone station were either complete or in progress. Based on the additional information, the NRC staff took action to address the issue to plant operators (see below). NRC Inspection Reports 50-423/88-05 and 89-02 describe NRC review of actions at Millstone.

Rosemount 1153 and 1154 pressure sensing units are used extensively in the safety related, environmentally qualified applications in the nuclear industry. Of 106 units in use at Millstone 3 (MP3), five failed in service in 1987. Subsequent reviews by the licensee concluded a potentially significant safety hazard (SSH) existed due to the failure mode and the widespread use of the instruments.

The results of the SSH were reported to the NRC in a March 1988 10 CFR 21 report. Subsequent review by the vendor, Rosemount, attributed the cause of the defects to the manufacturing process. Rosemount provided update information to users in a February 1989 letter that identified suspect units on a site specific basis, and recommended that utilities review the units for safety impact at their sites.

The problem was further studied by the Electric Power Research Institute using Millstone 3 data supplied from the Off Site Information System (OFIS). The failure mode was characterized as follows:

- The units fail from a loss of oil in the sensing chamber. That results in an inability to respond over the full span, an inability to respond in the increasing pressure direction, and a loss of dynamic response capability.

- The deterioration is gradual but has an "infant mortality" aspect. Failue can occur within 30 to 36 months after being placed into service in a high pressure application (greater than 1000 psi).

- The sensors can be significantly degraded in place (experience a loss of safety function) prior to the onset of detectable (observed) failure. A channel that looks operable to an operator during a panel check can be "failed-as-is" and incapable of responding in the upscale direction.

The detection of degraded units and identifying failures attributable to loss of oil is difficult. Identification relies upon accurate root cause determinations of failures at plant sites. It is probable that, as licensees review the failure data base for their plants, oil loss failures may exist but may not be identifiable. The ability to detect the failures is only as good as the level of detail with which the failure was described when entered into the data base (usually as part of the maintenance work order process), and only as good as the root cause analysis done.

Further, reviews of the calibration record for the plant may give a false security that the failure is not present, unless the review is done based on thorough guidance. Since the degradation is a slow process, a unit undergoing calibration during the early stages of failure may show only a slight amount of drift and this drift could be calibrated out during a test, or successively over several tests.

The satisfactory completion of response time testing has not been adequate to assure installed units are acceptable. Out of the 78 identified failures, only 1 or 2 were identified during response time testing. A problem in meeting the response time acceptance criteria will show up only when the unit is on the verge of obvious failure or already significantly degraded. The problem can be seen in its incipient stages during tests when units are subjected to their full span of pressures. This includes calibrations and response time tests

Licensee engineering reviews with the vendor determined that the first documented 1153/1154 failure (due to loss of oil) occurred in a unit with a 1979 shipping date, and the latest shipping date for a failed unit was in 1987. Just over 14,000 units were produced in that time in 300 lots. Of about 85 failures suspected to be from loss of oil, Rosemount found that 78 were due to low oil. Each of these failures were traced to its manufactured lot and 20 lots were identified as suspect. There were 1004 units in these 20 lots, and 16 of these units were supplied to Millstone.

The list of suspect batches for units identified in the February 89 Part 21 letter was developed from transmitters examined by Rosemount and known to have failed from loss of oil. Since the vendor does not have the capability to handle contaminated units, all failures have not been examined. It is estimated that the total number of failures from loss of oil may involve hundreds of units industry-wide.

In correspondence with the licensee dated December 8, Rosemount stated there have been no reported failures in sensors built in the last 3 years (1986 - 1988). The vendor reportedly made improvements in the process in that period to address the loss of oil problem. The vendor reportedly has more recently, through a combination of improvements in the manufacturing process and in-process testing criteria, improved the manufacturing reject rate. Although the manufacturing process for 1151 & 1152s transmitters is the same as that for 1153/1154s, the former units are used mostly in controls applications and non-EEQ safety applications, and reportedly have not experienced the failure mode.

Estimated Failure Probabilities

The licensee estimated the failure rate by relating the 78 loss of oil failures to the full manufacturing base produced from 1979 to 1987. The 78 failures represented 0.0565% of that manufacturing base. Using a round-up value of 1% defects in the manufacturing base, the failure rate for 1 year of service was then (0.01/8760 =) 1.1 x 10-6/hour. This failure rate compares favorably (1/30th) to the rate assumed for random failures in probabilistic safety analyses of 3.85 x 10-5/hr according to the licensee.

Inspector review concluded that the above predicts 0.014 failures in an 18 month operating cycle, instead of the 5 failures that actually occurred at Millstone 3. Also, of the 106 units installed at Millstone 3, 16 were

from the suspect lots. Five of these failed in service over the period from March - November 1987. The inspector therefore concluded that the licensee's estimate (1.1×10^{-6}/hour) was overly optimistic.

The inspector reviewed the methodology employed by Westinghouse in WCAP-10271-P-A, Evaluation of Surveillance Frequencies and Out Of Service Times For Reactor Protection Instrumentation System. In that methodology, the detectability of failures is an important factor that is accounted for explicitly in the calculations. Undetectable failures are defined by IEEE 379 as failures that cannot be detected by periodic testing or cannot be detected by alarm or anomalous indications.

The Millstone 3 studies show that the Rosemount 1153 transmitters can be significantly degraded in place for months (incapable of providing a trip function in the upscale direction), with this condition not detectable by any alarm or anomalous indication. The condition might be detected by periodic test, but the calibration surveillance interval is 18 months (13,140 hr) and the mean time to detect failures is 13,140/2 = 6570 hours. On the other hand, the WCAP methodology assumes a failed instrument will be detected within two operating shifts (i.e., 16 hours), a significant difference.

While the WCAP failure rate is 2.8×10^{-6}/hr and the licensee estimated a 1% defect (1.1×10^{-6}/hr), actual experience at Millstone 3 appears to be much worse. The WCAP assumed detection interval was 16 hours, at Millstone 3 it is 6570.

The WCAP concluded that the failure probability (P) using $\lambda=2.8 \times 10^{-6}$/hr and T=16 hour detection interval was acceptable, where:

$$P = \lambda T/2 = 2.2 \times 10^{-5}$$

Using T=13,140 hours and the licensee's assumed failure rate (1.1×10^{-6}/hr), the failure probability results would be approximately 7×10^{-3}.

Considering the 5 failures experienced at Millstone 3 in 18 months, the failure rate would be 4×10^{-4}/hr. This is a much worse failure rate than 1.1×10^{-6}/hr.

This matter will be reviewed further with the licensee to determine whether a more definitive failure probability can be obtained.

Further NRC Action/Followup

The NRC technical staff issued an Information Notice (IN 89-42) on April 21, 1989 advising the industry of the information available to the staff and requesting other utilities to review the matter for applicability for their plants. The present action plan for Millstone is to continue review of the 1153s and 1154s in safety-related applications for acceptable performance. The review includes testing as necessary to see if there is

evidence of degraded performance of the type described in the INPO Significant Event Notice (SEN) 57; i.e., sluggish response, slow drift of 1/4 percent or more, reduced noise in signal or change in normal system signal fluctuations, inability to respond over the entire operating range, etc. Suspect units would be further tested to confirm operability.

Wholesale changeout of suspect units that have yet to be proven inoperable was considered by the licensee but is not considered, by the licensee, to be the best course of action at this time. Until the full scope of the suspect lots is determined, there is a chance that new replacement units will also be susceptible to loss of oil failure. Further, unless additional data proves the "infant mortality" period invalid, a good confirmation that a given unit is not susceptible to the failure comes from the service time in high pressure applications without degradation. The best course of action appears to be to test installed units to detect signs of degradation. Test criteria from Rosemount are pending to assist this industry effort.

The licensee noted that preliminary Rosemount findings have suggested that the cause for the defects was related to a design change replacing an elastomer O-ring with a metal one to qualify the transmitter for harsh accident environments. The metal O-ring resulted in increased stress being applied to the glass sensing chamber. That caused cracking of the silica and eventual leakage. The O-ring was installed during final assembly after intermediate pressure tests of the sensing chamber were completed; thus, the assembled unit could be shipped with the incipient failure mode undetected. Rosemount review is in progress to recommend testing for the industry to better detect degraded units.

The inspector reviewed the bases for the licensee's conclusions regarding Rosemount transmitters and identified no inadequacies. Licensee initiatives to further review this issue included: testing on May 10 using the Great Neck Road training facility labs to record instrument pressure drop versus time to measure the rate of oil loss versus operating pressure; and use of the mockup flow loop to characterize the dynamic response characteristics of a degraded unit. Licensee actions during the refueling outage to further evaluate installed Rosemount transmitters will be reviewed during subsequent routine inspections.

Previous NRC resident inspection (IR 89-02) reviewed licensee actions to assure operability of Rosemount transmitters in safety-related applications at Millstone. These actions included verification of operability through response testing, calibrations, review of OFIS data, and review of channel performance during transients. Licensee actions were assessed as thorough in addressing the issue at Millstone 3.

9.0 Followup on Allegations (40500)

Followup of a Specific Safety Issue (RI-89-A-38)

A licensee employee contacted the inspector on April 5 to allege harrassment by a supervisor for bringing technical concerns to the NRC (reference Section 8.0 above concerning Rosemount transmitters).

The employee stated the harrassment occurred after presenting differing views to the NRC inspector during an inspection meeting at corporate engineering on March 30. The employee's supervisor was not in attendance during the meeting. Upon his return, the supervisor allegedly criticized the employee's performance at the meeting and restricted his further involvement with the problem. The employee stated it was inappropriate for him to be removed from the project due to his particular expertise in the issue.

The March 30 meeting was held at the inspector' request as part of the NRC inspection of the licensee's technical resolution of the Rosemount transmitter issue. During the meeting, the employee expressed views on the issue that differed from the general engineering consensus regarding the significance of the Rosemount problem, and in particular, the significance of the failure rate. Review of the matter by the NRC then concluded that the failure rate was not acceptable (see Detail 8.0, preceding) and the employee's safety concerns were substantiated.

Inspector observations during the March 30 meeting were that the employee's actions and statements were appropriate and beneficial to achieving thorough examination of all facets of the technical issue. The inspector noted further that the employee was especially capable in dealing with this issue due to his extensive involvement and study of the issue on an industry-wide basis.

The inspector informed the employee of the need to work with his chain of command and his rights to pursue the discrimination concerns with the Department of Labor. The employee pursued the issue through the NU Allegation Resolution Program. The employee contacted the Allegations Program coordinator and was referred to an outside consultant (LRS Associates) for followup of the technical issue. The administrative concerns were referred to licensee management.

The inspector reviewed licensee actions to resolve this issue. The technical and administrative issues were resolved to the employee's satisfaction. The licensee concluded that the employee's concerns were valid and that his continued participation in this matter was appropriate. Based on further NRC discussion with the employee, the licensee's allegations program was effective in resolving this instance of an employee-identified safety concern.

Review of Allegations Program Implementation in General

The inspector met with the NU Allegations Program Coordinator to review the history of issues resolved by the program in its first year since implementation in June 1988. The licensee stated that, while several individuals had initiated contact to resolve concerns, the only case intended to be addressed by MAP 4.16 (Millstone Employee Allegation Resolution Program) was the one summarized above. The inspector reviewed with the licensee the specifics of the worker concerns in two other instances. The concerns appeared to have been properly resolved.

The licensee stated that a new corporate procedure, NEO 2.15, was issued to incorporate the MAP 4.16 guidance on handling resolution of employee safety concerns. The licensee plans to eventually have NEO 2.15 supersede MAP 4.16. The licensee's assessment was that, while use of the program (in terms of the number of cases at Millstone and Connecticut Yankee) was low, the program was effective in resolving legitimate safety concerns. The licensee intends to continue with the present program.

Results of a recent licensee survey of employee views were being tallied by the licensee. The licensee stated the preliminary conclusions confirmed previous perceptions: workers have a high degree of personal regard for quality and safety in the performance of their jobs; and most workers do not feel the need to use the MAP 4.16 program since concerns can be worked out at the level of the immediate supervisor. The inspector noted the licensee's comments.

Routine NRC review of the licensee's programs for resolving employee safety concerns will continue on subsequent routine inspections.

10.0 Maintenance (62703)

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:

-- Weld Repair to Leaky Letdown Valve (3CHS*V995)
-- Auxiliary Feedwater Valve FWA*FCV31D1 Controller
-- Main Feedwater Valve FWS*CTV41A Limit Switch

No inadequacies were identified.

11.0 Surveillance (61726)

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:

-- Diesel Fuel Oil Transfer Pump Readiness Test, dated 5/1/89
-- "A" Motor Driven AFW Pump Readiness Test, dated 5/1/89
-- LPSI Injection Valve Stroke Timing, dated 5/8/89

No inadequacies were noted.

12.0 Management Meetings (30703)

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.