DPC

NRC FORM 464 Part I
(6-1998)

U.S. NUCLEAR REGULATORY COMMISSION

RESPONSE TO FREEDOM OF INFORMATION ACT (FOIA) / PRIVACY ACT (PA) REQUEST

FOIA/PA	RESPONSE NUMBER
2000-0145	1

RESPONSE TYPE: [x] FINAL [ ] PARTIAL

REQUESTER: Nancy Burton

DATE: APR 17 2000

PART I. -- INFORMATION RELEASED

- [ ] No additional agency records subject to the request have been located.
- [ ] Requested records are available through another public distribution program. See Comments section.
- [ ] APPENDICES — Agency records subject to the request that are identified in the listed appendices are already available for public inspection and copying at the NRC Public Document Room.
- [x] APPENDICES A — Agency records subject to the request that are identified in the listed appendices are being made available for public inspection and copying at the NRC Public Document Room.
- [ ] Enclosed is information on how you may obtain access to and the charges for copying records located at the NRC Public Document Room, 2120 L Street, NW, Washington, DC.
- [x] APPENDICES A — Agency records subject to the request are enclosed.
- [ ] Records subject to the request that contain information originated by or of interest to another Federal agency have been referred to that agency (see comments section) for a disclosure determination and direct response to you.
- [ ] We are continuing to process your request.
- [ ] See Comments.

PART I.A -- FEES

AMOUNT *: $ 19.00

* See comments for details

- [ ] You will be billed by NRC for the amount listed.
- [x] You will receive a refund for the amount listed.
- [ ] None. Minimum fee threshold not met.
- [ ] Fees waived.

PART I.B -- INFORMATION NOT LOCATED OR WITHHELD FROM DISCLOSURE

- [ ] No agency records subject to the request have been located.
- [ ] Certain information in the requested records is being withheld from disclosure pursuant to the exemptions described in and for the reasons stated in Part II.
- [ ] This determination may be appealed within 30 days by writing to the FOIA/PA Officer, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001. Clearly state on the envelope and in the letter that it is a "FOIA/PA Appeal."

PART I.C COMMENTS (Use attached Comments continuation page if required)

The actual fees for processing your request are as follows:

Search - 2 hours, 40 minutes -	**$104.00**
Duplication - 165 pages	**33.00**
TOTAL	**137.00**

Since you submitted advance fees in the amount of $156.00, you will receive a refund from the NRC Division of Accounting in the amount of $19.00.

SIGNATURE - FREEDOM OF INFORMATION ACT AND PRIVACY ACT OFFICER

Carol Ann Reed *Carol Ann Reed*

Re: FOIA-2000-0145

APPENDIX A
RECORDS BEING RELEASED IN THEIR ENTIRETY
(If copyrighted identify with *)

NO.	DATE	DESCRIPTION/(PAGE COUNT)
1.	Undated	Event Review Team Summary Report: Problem Statement: Two Control Rods, CEA 65 then CEA 63, Dropped to the Bottom Requiring a Manual Reactor Trip, and background information. (52 pages)
2.	1/1/00	CR Form - M2-99-3330. (1 page)
3.	1/6/00	CR Form - M3-00-0055. (1 page)
4.	1/7/00	CR Form - M3-00-0071. (1 page)
5.	1/27/00	Event Review Team Report - Unit 2 SG Level Manual Reactor Trip. (27 pages)
6.	1/27-28/00	Daily Events Reports for 01/27-28/00. (9 pages)
7.	02/11-14/00	Daily Events Reports for 02/11-14/00. (9 pages)
8.	02/01/00	Letter from James Linville, NRC Region 1, to Stephen Scace, transmitting NRC Combined Inspection 05000336/99014 and 05000423/990014. (84 pages)
9.	02/14/00	Letter from C. J. Schwarz to NRC, subject: Millstone Nuclear Power Station, Units 2 and 3, Monthly Operating Reports. (12 pages)
10.	02/24/00	Letter from C. J. Schwarz to NRC, subject: Millstone Nuclear Power Station, Unit No. 2, Licensee Event Report 2000-001-00 Manual Reactor Trip Due to Secondary System Transient. (12 pages)
11.	02/24/00	Region 1 Plant Performance Review, Millstone Unit 2. (53 pages)
12.	03/08/00	Reports from U.S. Nuclear Power Plants During the Y2K Transition. (4 pages)

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Event Review Team

Summary Report

Problem Statement: Two Control Rods, CEA 65 then CEA 63, Dropped to the Bottom Requiring a Manual Reactor Trip

CR M2-00-0373

3/6/00

ERT Lead, Steven V. Heard — Date
Root Cause Analyst, Robert C. Enoch
Root Cause Analyst, Eric J. Dean
Trainer, Robert L. Cimmino, Jr.
System Engineering, Lance LeBaron
System Engineering, Keith DesLandes
CBM Nuclear Technician A, Daniel F. Lowell

CR Owner, Stephen P. Brown — Date

Presented to PORC in preliminary form 2/16/00
PORC # 2/3-00-15

ITEM # 6

A/1

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1. Description of Event, "Explain what happened."

On February 11, 2000, Operations Surveillance test SP2620A, CEA Partial Movement, was being performed in the Control Room. In this procedure each control rod in turn is inserted five steps, then withdrawn the same five steps to its original position. The reactor was at full power, late in the fuel cycle, and all rods were at the full out position. This test satisfies Technical Specification 4.1.3.1.2, which in turn demonstrates the operability of the control rods. The control rods are tested in the same order as the control rod groups are withdrawn, beginning with the Shutdown banks A and B, then groups 1 through 7.

CEA 65 has had a history of previous problems. In September, 1999, the rod had dropped, precipitating a plant shutdown. The apparent cause was chafed cables coming from the lower gripper coil stack. This caused a ground, which resulted in large negative currents and a resulting blown fuse. The corrective action was to sheath the chafed cables. This eliminated most of the negative current indication, and at the time was considered adequate.

Due to this previous problem, I&C had been asked to monitor the test of CEA 65. The surveillance was halted when group 6 had been completed, and Operations waited until I&C was in position to observe. When the test resumed, I&C monitored the test at the cabinets. Group 7 CEAs were tested without incident until CEA 65, the next to last rod in the test. At 1329, when the operator inserted CEA 65, it immediately dropped to the full in position. The immediate cause of the drop was a blown 'B' phase fuse in the power supply. Reactor power decreased in response to the inserted rod. A power reduction was initiated at 1343 to bring the reactor power to 70%, the highest power level at which the rod could be withdrawn with out threatening any power limits.

Earlier in the test sequence, when group 3 was tested, CEA 63 had shown no hint of a problem as it was stepped in and out at 1303. However, either immediately after the last step, or soon thereafter, something caused the high and low current relays in the upper gripper 'A' phase power switch to fuse shut. It is likely that one of the reed relays was previously stuck for some time as it appears improbable that both would stick at the same time. This caused the power switch for phase 'A' to remain at full current. The upper gripper coil is the only one of the five coils that is normally energized, so that the closed relays had no immediate effect. However, the continuous high current did exceed the limit of the fuse, and this led eventually to the failure of the 'A' fuse at 1346. This was 43 minutes after CEA 63 had been tested, 27 minutes after CEA 65 had dropped, and three minutes after the reactor downpower had begun.

CEA 63 dropped to the full in position. The operators recognized that with two rods inserted AOP 2556 called for a manual reactor trip, and seven seconds later, after verifying the condition, the reactor operator initiated a manual reactor trip.

2. Historic Review, "Explain when it happened before and what corrective actions were taken."

In September of 1999 CEA 65 dropped. Current traces identified a definite ground. This was traced to a chafed wire at the head. An insulating sleeve was installed. The phase 'A' and 'C' 15 amp fuses were also replaced. Current traces taken after these repairs did not match ideal traces. Some negative dips were identified in both the withdrawal and insert sequence. Combustion Engineering, Dave Story, was enlisted to evaluate the traces. Considering the traces he recommended that once the rod was in position not to move it. Leaving the rod stationary once withdrawn could not be accomplished, Technical Specification Surveillance Requirements require monthly rod motion of any not fully inserted control rod to ensure rods are trip-able.

~ 2 weeks ago CEA 65 slipped. No investigation was performed to determine cause. When I&C personnel were set up to test, the rod moved normally and was withdrawn to the proper position.

3. Analysis, "Explain the failure mode, how, and determine why it happened."

CEA 65 'B' phase 15 amp fuse was found to be blown. There is a question regarding breaker sizing. Saint Lucie (SL) has 15 amp fuses installed. Each refueling outage SL replaces these 15 amp fuses. They are not experiencing the same number of control rod drops. Other Combustion Engineering designs have eliminated or have never had the 15 amp fuses. A circuit breaker with proper current interruption capability has been provided. The current through the fuses for the upper gripper, lower gripper, and the lift coils exceeds in amplitude the 15 amp fuse rating. The period, amount of time the fuse is exposed to these high currents, is typically too short to cause the fuse to fail for any event of normal duration. The 'B' phase fuse was replaced and a retest attempted. After two steps out the 'B' phase fuse failed. The fuse was replaced. Additionally, this time the Upper Gripper Power Switch and the Pull Down Power Switch were replaced and CEA 65 was withdrawn (8 steps) and inserted twice.

Voltage readings were taken on power supplies, coil impedance was measured and cables were megger checked, these readings were all satisfactory. Technicians replaced phase 'B' 15 amp fuse. When moving the rod to obtain current traces the rod stepped out ~ 2 steps and 'B' phase 15 amp fuse blew again. The 15 amp 'B' phase fuse, the Pull Down Coil Power Switch and the Upper Gripper Power Switch were replaced. These power switches were replaced based on somewhat unusual current traces on the second step of CEA 65. Following this, CEA 65 was tested twice, 8 steps out and 8 steps in, and current traces were obtained. Although the current traces did not match the ideal traces they do match traces that were obtained in September. Combustion Engineering was previously contacted with respect to the current traces for CEA 65 and attributed the trace to a slight ground in the coil stack for the rod. No other rods exhibit this negative dip in their current readings.

During this outage this coil stack has been replaced. When the coil stack was replaced for CEA 65 boron was identified on the outer portion of the connector shell. This resulted in additional conduit/cable being replaced. All rods will have current traces obtained prior to restarting the unit as a part of Hot Rod Testing.

With regard to CEA 63, something caused the high and low voltage reed relay contacts in the upper gripper 'A' phase power switch to fuse shut either immediately after it's last step during rod control testing or soon thereafter. This caused the Upper Gripper Power Switch for phase 'A' to remain at full current. The continuous high current did exceed the limit of the fuse, and this ultimately led to the failure of the 'A' phase fuse.

This is an excerpt from a letter associated with troubleshooting performed by Combustion Engineering on some failed Maine Yankee Power Switches.

> "The other component found defective in the power switch modules was the reed relays. In each power switch module, two out of three reed relay contacts were fused together due to arcing. This was also the result of rapid and random cycling of the relay module due to the insufficient operating voltage produced by the defective 15 volt dc logic power supply."

Six years ago MP2 had experienced problems with the 15 volt dc logic power supplies. A subsequent modification (larger current capability supplies) was performed improving the voltage stability and to eliminate end of life issues. Understanding what was discussed above, that the low voltage could cause premature failures of the reed relay contacts, I&C performed power supply voltage checks of all the 15 volt dc logic power supplies, all were satisfactory. In addition I&C is performing contact resistance checks of the reed relay contacts on each of the power switch modules. The low voltage experienced years ago may have left a legacy of high resistance contacts. Pitted high resistance contacts could cause arcing which could lead to overheating and finally fusing of the reed relay contact. A fused reed relay contact was found in the Upper Gripper Power Switch for CEA 63. Two other rods have exhibited this fused reed relay failure mode.

Why do the Upper Gripper Power Switches exhibit more failures than the other 4 power switches? With the rods latched the upper gripper power switch is gated to supply power at reduced current to the upper gripper (stationary) coil which holds the control rod in place. The power switches (upper gripper, lower gripper, load transfer, pulldown, and lift coils) are gated temporarily in both the withdrawal and insertion sequence. The power switches are interchangeable. The current values seen by the upper and lower gripper coils is 20-22 amps for ~ 20 milliseconds, the lift coil sees ~ 40 amps for 20-30 milliseconds. The load transfer and pulldown coils see lower currents. Combustion Engineering has instructed our I&C technicians that if the Upper Gripper develops a problem use the Pulldown module. Due to rod speeds that we have the pulldown coil is not necessary. During this outage Combustion Engineering provided a test and acceptance criteria for the SCRs in the power switches, a SCR failing the acceptance criteria may still be functional but is degraded. The SCRs in all power switch modules were tested. The following table provides the results of that testing. Note that the Upper Gripper power switch has one of the highest number of failures to meet acceptance criteria. Note also that a number of unsatisfactory readings were identified in the Pulldown modules. Poor record keeping with rod control problems leads us to presume that these degraded Pulldown modules were once utilized as Upper Gripper Modules and when rod control problems existed they were switched. The Upper Gripper modules see greater duty cycles therefore the Upper Gripper Power Switches appear to be more susceptible to age/duty cycle related failures.

Power Switches with Failed SCR's

CEDM Number	Lift Coil	Upper Gripper	Lower Gripper	Pull-Down	Load Transfer
1					A
2		A			
5	C				
7				B	
9				A	
20				A	B
29	A				
31		A	C		B
43				B	
44		C			
47		C			
54				B	C
63		A			

The letter indicates the phase that was found degraded.

Intermittent failures in the rod control system have historically been corrected by replacing power switches and/or timer modules. These modules have been returned to Combustion Engineering for evaluation repaired without extensive failure mode determination. If the modules are tested at Combustion Engineering and no deficiencies are identified, they are returned to the warehouse to be used as spares. We have not requested any detailed troubleshooting or failure mode determination until recently. The maintenance history is not well documented with respect to what repairs have been made to any particular module and where that particular module has been throughout it's life in the rod control cabinets. Testing spare modules identified 4 SCRs that did not meet the acceptance criteria provided by CE.

MP2, T.S. 3.1.3.1.e states that with 1 rod misaligned $\geq$ 20 steps, reduce thermal power to $\leq$ 70% within one hour. If negative reactivity is required boration shall be used. Then within one hour after reducing thermal power, restore the rod. Combustion Engineering Improved Standard TS were evaluated and it too requires a downpower followed by restoring proper control position. The new Improved Standard TS surveillance requirement is to once every 92 days, exercise control rods rather than our current rod test every 31 days.

I&C was not prepared to immediately replace a blown fuse for any particular CEA. The basis for this is that there is no urgency to replace the fuse, as the rod cannot be withdrawn until the plant is at 70% power.

Lack of an effective preventative maintenance program appears to be a player in the failure frequency of the CEDS. Other CE plants have structured replacement and testing programs for power switches as well as complete bench testing capability. MP2 has not performed any extensive PMs on the power switches for the rod control system.

Analysis

Based on the information currently available, the ERT is unable to determine conclusively the precise failure precipitator. Rod 7-65 appears to have a ground somewhere in the circuit between the cabling and the coil stack. This is indicated by the current transient taken when the rod is withdrawn or inserted.

Rod 3-63 appears to have tripped due to failed relays in the upper gripper circuit. The failure mechanism for the relays is unknown. (Information in the supplementary report indicates a failed potentiometer in rod 63 upper gripper power switch).

There appears to be a relationship between Power Switch failure and fuse failure, most of the failures are paired (fuse and power switch fail concurrently). A low voltage in the Coil Power Programmer Power Supply has been postulated to cause a failure of the reed switch (relay) in the Power Switch as a result of less than full deflection of the reed and subsequent arcing at the contact interface. Any other phenomena which could cause low voltage in the circuit, for example high resistance in the fuse block, could result in accelerated failure of the relay. The above analysis is somewhat anecdotal in nature as there is no apparent hard evidence that supports the "low voltage-relay failure" specific to the CEDS although there is general industry evidence that insufficient pull-in voltage for relays can result in "chattering" and "contact degradation."

The only major components that have not been replaced in rod 7-65 are the coil stacks and the interposing cable.

Rod 65 dropped as a result of a blown fuse. The blown fuse appears to have been caused by an intermittent fault in the coil stack. Rod 63 dropped as a result of a blown phase A fuse. Subsequent testing revealed that the high and low current switches for the A phase of rod 63 of the upper gripper power switch are fused shut. The condition of the power switches results in drawing current in excess of the rating of the 15 amp fuse in the system. The rating of the fuse is such that it should blow in 300 seconds (5 minutes) with a steady current of 22 amps. The fuse should not blow with a current of less than 15 amps. Since the rod dropped due to a blown fuse about 43 minutes after it had been tested, the coil was probably drawing between 15 and 22 amps (likely closer to 15 amps) resulting in eventual blowing of the 15 amp fuse. Subsequent testing indicated that a potentiometer in the power switch was grounded which is a credible causal mechanism for the failure of the reed relay switches.

While the CED System is capable of performing its safety function, plant reliability issues warrant further action prior to restart. Plant management should decide on any additional actions to allow restart following completion of corrective actions to prevent recurrence recommended below.

4. Recommended Corrective Actions

Remedial

CEA 63: Replaced the 'A' phase 15 amp fuse. When the trip breakers were closed the fuse immediately blew. This is indicative of a failure in the Upper Gripper Power Switch. The Upper Gripper Power Switch and the 'A' phase 15 amp fuse were replaced. Rod was tested twice, 8 steps out and 8 steps in, obtaining current traces. The current traces closely matched the ideal traces. Power switch has been sent to CE for testing and failure determination.

Corrective Action to Prevent Recurrence

Recommend the 15 amp fuses be upgraded to 30 amp fuses. Change the existing fuse blocks to accommodate these larger fuses. Replace the 35 Amp neutral fuses like for like. **(Complete)**

Recommend that resistance checks of each SCR in each Power Switch module installed and spares be made following the Combustion Engineering guidance.)SCRs were tested in both the installed and spare Power Switches using a Simpson 270 Analog Ohmmeter, or its equivalent. Numerous SCRs did not pass the acceptance criteria. These SCRs have been replaced.) **(Complete)**

Recommend installing Power Switch modules with fewer duty cycles in the Upper Gripper slot location. The Pulldown module Power Switches were switched with the Upper Guide Power Switches. **(Complete)**

Recommend replacing the coil stack for CEA 65. The coil stack and cable/conduit for CEA 65 were replaced. **(Complete)**

Test contact resistance for all reed relays. Replace any exhibiting unusually high contact resistance. **(Complete)**

Additional Corrective Action

Obtain current traces on all rods and compared with ideal traces prior to restarting the unit.

Establish a program for periodic refurbishment (preventative maintenance) of Power Switch Modules.

Establish maintenance history control for each CEDM drive and power switch in a manner not unlike a loop folder for instrumentation (this is to aid in determining history for a specific power switch).

Send CEA 65 coil stack to Combustion Engineering for failure mode determination.

Send 15 amp fuses which had been previously installed in the CPP for the CEAs for testing for reduction in rating or other aging/cyclic failure modes.

Verify setting of the 15 volt dc logic power supply for all CEAs. According to Combustion Engineering, insufficient voltage has resulted in rapid and random cycling of the relay module causing the reed relay contacts to weld (fuse) closed.

Evaluate and implement, as appropriate, the Optimization Strategy for control rod testing in Attachment 1.

Evaluate the need for a design change to power switch/reed relay to replace with a more reliable component configuration and implement as appropriate.

Change MP2 T.S. to be able to utilize the extended period for the surveillance test, test every 92 days versus 31 days.

5. List of CR numbers and title of Other Equipment Malfunctions or Human Errors associated with this event.

   See table of CRs generated which were associated with this event (Attachment 6). There were no human performance errors associated with the rod drop.

6. List Personnel Interviewed.
   Boyce Atkinson
   Steve Brown
   Steve Nix
   Jim Ritchie
   Pete Smith
   Doug Vining
   Operating Shift Personnel, personal statements, no additional insight into specific rod drop event.

7. Document Reference Material Used.
   RP 17, "Event Review Team"
   MP2 Technical Specification Section 3.1.3.1
   MP3 Technical Specification Section 3.1.3.1
   AOP 2556, "CEA Malfuntions," Section 4.2.1 and 4.2.2
   EOP 2525, "Standard Post Trip Actions"
   SP 2620A, "CEA Partial Movement"
   Lesson plan IC 00459T, "CEDS"
   MSEE/DCN DM2-00-0132-00 & DM2-01-0132-00, "CEDM Power Supply Fuse Replacement"(added fuse resistance and revised to eliminate the need to do thermography)
   CR M2-99-2468, "(R) Entered TSAS 3.0.3 Due To Failed Timer Module For CEA 7-65"

Attachment 1

Optimization Strategy To Prevent Future CEA Drops

I. I&C Prestaged Equipment

A. Diagnostic/Repair Procedure

B. Astro-Med Recorder

C. UG Power Switch Parallel Key

D. CPP Power Supply Voltage Tester (DVM)

E. 15 amp Main Power Fuses (3)

F. 6 amp CPP Power Supply Fuses (2)

II. Start test with CEA 65, followed by other "high-risk" CEAs

III. Before each CEA is tested/exercised:

A. Verify CPP power supply output voltage

B. Ensure Astro-Med connected and ready to record CPP pulses

IV. If voltage on **both** CPP power supplies test sat., Then proceed with SP-2620A test of applicable CEA

A. If CPP power supply voltage unsat, adjust power supply voltage and retest/proceed as applicable

V. If Astro-Med indicates improper CPP response during CEA movement, proceed as follows:

A. DO NOT proceed to next CEA in surveillance

B. Parallel faulted CEA with counterpart (UG parallel key)

C. Replace faulted CPP power switches as necessary

D. Verify 30 amp power fuses NOT blown (**all three** phases)

E. Unparallel CEAs and retest faulted CEA

F. If test sat, continue with SP-2620A

Attachment 3

I&C Trouble Shooting Activity

1. I&C Technician in Control Room notified that CEA 65 has dropped.
2. I&C Technician contacts the I&C shop and requested additional support.
3. I&C Technician verifies that the Coil Power Programmer (CPP) power supplies are de-energized.
4. I&C Technicians and CBM verified that the 'B' phase fuse for CEDM 65 was open.
5. Unit is Manually tripped prior to fuse replacement due to CEDM 63 dropping.
6. I&C Technician verifies that the 'A' phase fuse for CEDM 63 is open
7. I&C Technician performs Insulation Resistance checks on CEDM 65 wiring, all readings are within allowable values (>100 Meg)
8. I&C Technician performs Resistance checks on CEDM 65 coils, all readings are within allowable values.
9. I&C Technician performs Insulation Resistance checks on CEDM 63 wiring, all readings are within allowable values (>100 Meg)
10. I&C Technician performs Resistance checks on CEDM 63 coils, all readings are within allowable values.
11. Fuse is replaced in the 'B' Phase of CEDM 65.
12. Trip Circuit Breakers are closed
13. CEDM 65 is re-energized and the 'B' Phase Fuse opens immediately.
14. Upper Gripper and Pull-Down Power Switches for CEDM 65 are replaced.
15. Fuse is replaced in the 'B' Phase of CEDM 65.
16. CEDM 65 is withdrawn and inserted, Coil Current traces are taken, coil currents are within nominal range.
17. Pull Down coil current is measured to be approximately 20% less than the previous measurement.
18. Negative going pulse is seen on several traces, Pull down and upper gripper.
19. Fuse is replaced in the 'A' Phase of CEDM 63.
20. CEDM 63 is re-energized and the 'A' phase fuse for CEDM 63 opens immediately.
21. The Upper Gripper power switch is replaced
22. Fuse is replaced in the 'A' phase of CEDM 63
23. CEDM 63 is withdrawn and inserted, Coil Current traces are taken, coil currents are within nominal range.
24. All primary fuses, except for CEDM 63 and 65, are removed from the CEDM cabinets and labeled.
25. Troubleshooting is conducted on failed upper gripper power switch from CEDM 63, the high and low current control relays are found to be welded shut for the 'A' phase.
26. SCR's in failed power switch modules are tested, potentially failed SCR is identified in former CEDM 63 upper gripper power switch.

Attachment 4

Historic Rod Problem Areas

7-38

9/23/99	Upper Gripper Power Switch replaced, Blown Phase B fuse, loose connection (CR M2-99-2518)
3/15/99	Replace timer module (CR M2-99-0946

7-65

4/23/94	UG Power Switch replaced, Logic Power Supply replaced
6/17/94	UG Power Switch replaced
4/28/99	Blown Fuses (Unknown)
5/9/99	All Power Switches replaced, (5)
9/17/99	Coil Ground, sleeved and shrink tubed
9/22/99	Blown fuses, replaced
1/29/99	Slipping, exercised, no repair
2/12/99	Phase B fuse blown, replaced fuse and Pull Down Power Switch

6-17

1/8/93	Pull Down Power Switch replaced
3/15/99	Replaced timer module (CR M2-99-0946)

5-5

1/11/91	Voltage adjusted up

3-60

4/99	UG Power Switch
5/28/99	Lift Coil Power Switch

3-63

2/11/00	UG Power Switch, Phase A fuse replaced (CR M2-00-0373)

2-18

12/14/95	UG, Lift power switches replaced, Fuses replaced (Unknown)

2-22, 2-23

1988	Boron overheat replace some parts

1-27

1/93	Blown fuse,
9/17/99	LG Power Switch

1-30

8/3/95	Logic power supply replaced
9/17/99	Blown phase B fuse

Attachment 4

Historic Rod Problem Areas

A-44

6/82	Loose Connection
8/1/95	Blown phase A fuse

A-49

9/22/99	Blown phase C fuse, unknown blown fuse

Attachment 5

Mr. Albert

May 11, 1994
NOME-94-N-0346

There are two reed relay modules inside each power switch, with three individual reed switch contacts inside. The two reed relay modules switch the three SCR's located in the power switch module on and off when selected by the timer module. The reed relays require nominal 12 volts dc to create a sufficient magnetic field strong enough to simultaneously close the three individual reed switch contacts inside. The required 12 volts is derived from the 15 volt dc logic power supply via four dropping diodes in the CPP timer module. When the two relay modules in each power switch are energized by 12 volts dc they simultaneously switch a voltage signal to the SCR gate circuit turning on the three SCR's. When the 12 volts is removed from the two relay modules the reed switch contacts open removing the gate voltage signal from the SCR gate circuit and the SCR's turn off. This sequence is controlled by the CPP timer module. When the timer module is in the stationary or hold mode of operation a steady 12 volts dc is supplied to the relay module in the upper gripper power switch maintaining the control rod in the withdrawn position. However, if the voltage to the relay module coil is at or just below the minimum voltage required to operate, (approximately 10 volts) the relay coils magnetic field strength will not be sufficient to hold all three reed switch contacts closed. The field strength at the time may only be sufficient to hold two relay contacts firmly closed with the third contact operating, intermittently switching the 5CR on and off rapidly. This problem will randomly change to the other two relay contacts and in turn to the other two SCR's while the power supply voltage remains around the minimum operating voltage of the reed relays. The random and rapid switching on and off of the SCR's over a period of hours creates excessive heat within the SCR at the cathode to anode junction. The excessive heat breaks down the junction area between the SCR's anode and cathode creating an internal short circuit forcing the SCR to remain energized continuously. This type of failure was found in the upper gripper, lower gripper and pulldown power switches removed from Maine Yankee. The other component found defective in the power switch modules was the reed relays. In each power switch module, two out of three reed relay contacts were fused together due to arcing. This was also the result or rapid and random cycling of the relay module due to the insufficient operating voltage produced by the defective 15 volt dc logic power supply

Either of the two failures mentioned were sufficient to keep the grippers engaged against the drive shaft and prevent the movement of the Control Element: Assembly (CEA).

In conclusion. I recommend you replace the upper gripper power switch module for CEA No. 65. and adjust all your power supply outputs to ±15 volts dc +0.1vdc/-0.0vdc If you have any further questions, please feel free to call me at (203) *285-3065.*

Sincerely, ABB COMBUSTION ENGINEERING NUCLEAR OPERATIONS

David A. Story

Attachment 7

List of M2 CRs from Word Search of Document Text and Notes

Word Search Criteria: TRIP *15 Feb-00*

Between: 02/11/00 and 02/15/00

1	M2-00-0372	02/14/00	2	IT WAS DISCOVERED THAT PLANT TRIP MUFFLERS AUTOMATICALLY RELEASED STEAM ON THE S/G ATMOSPHERIC DUMP MUFFLERS. Condition Description: Electricians have AWOs to work Heat Tracing on the S/G Atmospheric Dump Mufflers. Today it was observed during the plant trip that these mufflers automatically released steam. This is a near miss. Had the electricians been working on these mufflers during the plant trip, serious injury would have occurred. The question had been asked earlier about the possibility of steam release. The response was that valves had to he manually aligned for this to occur.
2	M2-00-0373	02/14/00	1	(R) WHILE PERFORMING CEA INSERTION TESTING, DROPPED FULLY INTO THE CORE, WHICH REQUIRES A MANUAL REACTOR TRIP. Condition Description: While performing CEA insertion testing per SP2620A, CEA 65 dropped fully into the core. — 17 minutes later. CEA 63 also dropped into the core. This resulted in 2 dropped CEAs which requires a Manual Reactor Trip. The Trip was performed. The second CEA (63) dropped while performing the downpower to < 70% for the first Dropped CEA (65). During the trip, VR-21 shifted to its alternate power supply. This was also noted on the Reactor Trip of 1-24-00.
3	M2-00-0374	02/14/00	3	DURING REACTOR TRIP VR-21 SHIFTED ITS ALTERNATE SOURCE. RESULTED IN MINI FLOW VALVES GOING TO MANUAL CLOSE. Condition Description: During the Reactor trip, VR-21 shifted to its alternate source. This resulted in the SGFP Mini Flow valves going to manual closed. This is not a desired condition for continuing operation of Feed Pumps after a Reactor Trip. The System Engineer notified the Control Room of his concern and min flow was restored. Second Stage Reheat MOVs (2-MS-2A&B) did not automatically close at the 10% Turbine Load Decreasing Point. The RCS cooled down to —527 degrees until 2- MS-2A&B MOVs were closed from CO-6 to isolate Steam flow.
4	M2-00-0376	02/14/00	1	AUTO AUX FEEDWATER WAS ACTUATED FOLLOWING THE MANUAL REACTOR TRIP OF 2/11/00.

Attachment 7

List of M2 CRs from Word Search of Document Text and Notes
Word Search Criteria: TRIP *15 Feb-00*
Between: 02/11/00 and 02/15/00

				Condition Description: Automatic Aux Feedwater was actuated following the manual reactor trip of 2-11-00. Following the reactor trip, the Second Stage Reheat MOVs (2-MS-2 A&B) failed to automatically close (see M2-00-0374). This caused an RCS cooldown beyond that of a normal trip, causing an additional shrink of Pressurizer and Steam Generator levels. The third charging pump started in response to decreasing pressurizer level. The S/G level setpoint for Automatic AFW actuation was reached. Both electric AFW pumps and the AFW reg valves operated as expected. This is a Reportable Event based on an Engineered Safeguards actuation.
5	M2-00-0379	02/14/00	2	LOOSE PARTS MONITOR FAILED FOLLOWING REATOR TRIP. ALARM ANNUNCIATED. Condition Description: Loose Parts Monitor failed following Reactor Trip of 2-11-00. Following the reactor trip, the Loose Parts Monitor alarm annunciated. The Alarm Response Procedure was followed in response to unusual indications on the LPM control panel, C-24. The red CCSC Status light was lit, and I&C was notified.
6	M2-00-0380	02/14/00	3	ICC LEVEL TRAIN B FAILED FOLLOWING REACTOR TRIP. SEE CR M2-00-0245 FOR PREVIOUS OCCURRENCE. Per final MRT this CR is closed to CR M2-00-0245. - Condition Description: ICC Level Train B failed following reactor trip of 2-11-00. HJTC #6 in Train B is intermittently failing high resulting in intermittent failed or X flags for ICC level Train B on the PPC SPDS displays. See CR M2-00-0245 for previous occurrence.
7	M2-00-0383	02/14/00	3	FOLLOWNG THIS TRIP AND THE PREVIOUS TRIP, THERE IS A HYDRAULIC HAMMER IN THE DRAIN LINES FROM BOTH MOISTURE SEPRATOR TANKS TO THE CONDSR Condition Description: Following both this trip, and the previous trip, there is hydraulic hammer in the drain lines from both Moisture Separator Drain Tanks to the Condenser (the lines with 2-ES-70A & 2-ES-70B in them). The surge can be beard fairly widely throughout the southern end of the Turbine Building (primarily on the 31 ft 6in

Attachment 7

List of M2 CRs from Word Search of Document Text and Notes
Word Search Criteria: **TRIP**
Between: **02/11/00 and 02/15/00**

15 Feb-00

and 14ft 6in levels). The surge is sufficient to cause the check valves (2-ES-70A & 2-ES-70B) to repeatedly impact their seats. The surge is occurring with a frequency a little higher than 1 impact per second.

Supplemental ERT Report - Post Retest Activities

The ERT provided a single reed switch (discolored, apparently oxidized) to the chemistry department. An experiment was performed to determine if that reed switch had lost vacuum. The reed switch placed in a vacuum chamber in a flask of water. A hard (25" Hg) vacuum was drawn on the flask and maintained for two hours. At the end of abut two hours, the vacuum was broken with the reed switch under water. The switch was left in the water for about two hours and then inspected for water intrusion. No water was noted, QED, the switch remains hermetically sealed.

I&C disassembled two reed relays which had good and high resistance contacts. Visual observation did not identify any significant difference in a high contact resistance reed switch versus a low contact resistance reed switch. I&C then performed bench testing of removed reed switch relays. The coil voltage applied was 12VDC, which is adequate to maintain the contacts in a closed state. While testing the bench surface was tapped, surprisingly the contact resistance changed. I&C said one of these test resulted in the contact resistance going to full open. The DMM supplies minimum voltage/current through the contact to measure the resistance. Therefore the failure initiator appears to be the mechanical shock applied when tapping the bench top.

Failure modes of the CPP Power Switch

There are three major components which can fail within the Power Switch which can result in a rod slip or a rod drop. The failures may also result in fuse opening or breaker action.

Each power switch contains three power SCRs, three pilot SCRs, six reed relay contacts (three low power and three high power) and six wire wound potentiometers.

If a potentiometer fails, it will usually short to ground which will blow the fuse or breaker for the affected phase of power. When the potentiometer fails it will short to the chassis(which is grounded) which will cause a voltage spike across the affected reed contact thus fusing or 'bridging' the reed contact. The potentiometer should be changed. The reed contacts should be checked to determine proper status (not fused). The SCRs in the circuit should be checked and any faulted ones should be replaced.

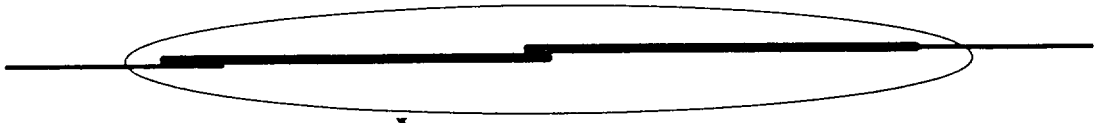
If the potentiometer is found bad and the SCR and reed contact are not checked, the power switch is likely to cause another fuse actuation or breaker trip.

The reed contracts within the power switch are very sensitive. If a high resistance is found across an energized closed contact, a slight bump will cause the reed contact to clear or have a very low resistance.

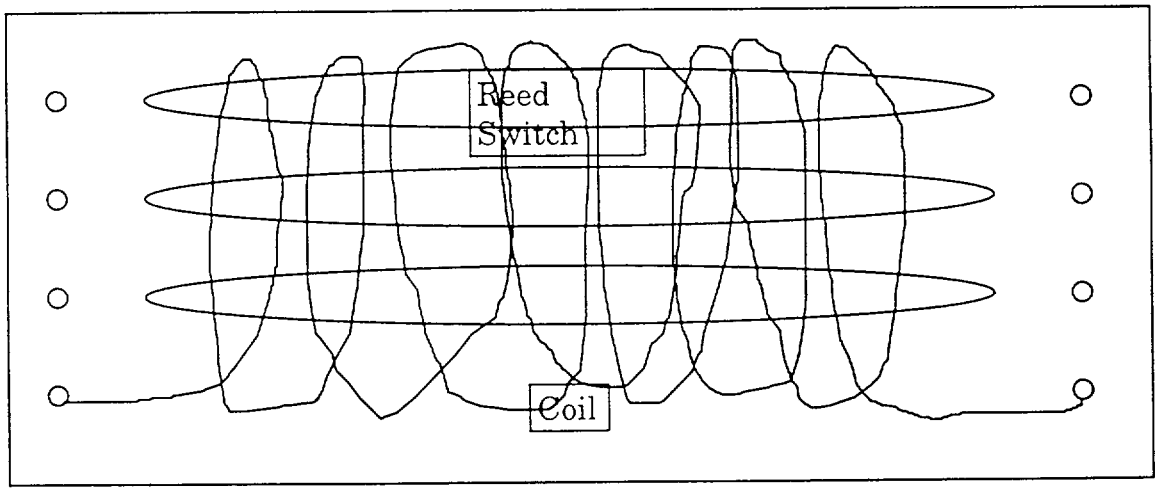
During rod testing following SCR testing and replacement and Reed Relay testing and replacement, a number of rods exhibited problems ranging from failure to move on demand to blown fuses to tripped circuit breakers. The rods and associated failures are detailed in the following table.

Rod #	Symptoms	Action	Comments
CEA 3 (PMT)	Trace improper and could not be adjusted (ran out of pot)	Swapped pull down and upper gripper power switches and problem corrected. Later, a good switch was inserted in the pull down slot.	The 'bad' power switch was sent to CE for testing and repair. No repair required. CE was able to adjust power supply to proper value.
CEA 47 (PMT)	Rod did not move with group. Traces indicate good power switch & coil integrity	Verify coil stack alignment (circuit breaker presently open) Voltage set too low.	The only problem was that voltage was set too low to develop a proper signal to the coils to lift the rod. Corrected on-site.
CEA 65 (PMT)	Blown B phase fuse, circuit breaker tripped.	Power switches removed and tested one at a time. Bad lower gripper power switch.	This rod has had the same power switches since 9/99. Possible fault in coil stressed power switch causing premature failure.
CEA 40 (PMT)	Tripped circuit breaker.	Replaced lower gripper power switch. Tested sat	Power switch sent to CE for testing. Other than having to adjust voltage, no problem noted with lower gripper power

			switch
CEA 41 (PMT)	Rod failed to move.	Bad Lift power switch, replaced tested sat.	No additional action.
CEA 49 - No MNTC performed, no reed relays or SCRs replaced	Blew "C" phase fuse	Replaced fuse. Power switches tested sat. Indicative of some non-repeatable fault somewhere in the system.	CEA 49 has blown 'C' phase fuse before. Fuse replaced, no repair activity. Recommend coil stack replacement during upcoming outage.
CEA 63	Original Upper Gripper blowing "A" phase fuse	Unknown cause	CE tested and determined there was a shorted potentiometer on the Upper Gripper LO current power supply, Phase "A"
CEA 64	Lower Gripper not engaging, rod not moving	Unknown cause. Lower gripper power switch replaced	CE tested and determined voltage was out of adjustment.
CEA 23	Noise on pulldown trace.	Bad pull down power switch; replaced	No additional action.



Glass case, vacuum, reed relay contact.
No voltage rating make and break 3
Amps DC and will carry 5 Amps DC,
1000VDC interrupt, contact interrupt
rating of 50 Watts of a Tungsten Load.
New Product Engineering
760-1-2 K2
Wabash, IND.



ECAD has performed testing of cables to determine location of any existing faults. Cables for CEA 65 and CEA 49 were tested with no detection of any faults. This testing provides a high level of confidence of system conductor integrity

One additional difference noted in how we operate the system and how other similar vintage CE plants operate is that Calvert Cliffs powers up the system from the MG Sets by first closing the Reactor Trip Breakers (TCB) then closing individual CEA breakers. Millstone's practice is to close the CEA breakers then close the TCBs. Combustion Engineering recommended that Millstone change this practice to close the TCBs then close each CEA breaker. This applies load to the MG set in smaller increments. This will eliminate potential spikes on the MG set.

Conclusion of supplemental ERT Investigation

Of all the 'failures' noted during rod testing following SCR and Reed Relay replacement, all except one is attributable to identified system deficiencies which might reasonably be expected to occur following extensive maintenance activities in the CPP cabinets. The original (from the trip) Rod 63 power switch was determined at CE to have a faulted potentiometer; Rod 3, 61, 64, and 40 all required voltage adjustments to enable the power switches to function properly, no other faults were found at CE. Rod 41 was determined to have a bad power switch which was replaced.

Rod 49 is the only rod which is identified as having future problem potential at a higher rate than the other rods. This rod has tripped the 'C' phase before and subsequent testing failed to determine any fault. When the 'C' phase fuse blew during testing on 2/17, no fault was detected, the fuse was replaced and the rod performed perfectly. Rod 49 has not exhibited any tendency to slip but it has failed to move. If the 'C' phase fuse is the only fuse that blows, a dropped rod should not result as the logic power supplies will continue to function.

Rod 65 blew a fuse when tested following replacement of the coil stack. The faulted power switch was associated with the faulted coil on rod 65. The evidence of the small spike in coil current during movement of rod 65 and the intermittent performance (slipping, dropping) indicate the presence of a fault in the coil. It appears that the fault periodically became serious enough that the rod would either slip due to lack of proper current flow in the coil or the current flow would become large enough to blow a fuse and cause the rod to drop. The same fuses and power switches have been installed in rod 65 since September. The ERT postulates that the intermittent fault accelerated the aging of the power switch and fuses such that failure occurred during post maintenance testing this outage. ECAD performed testing on the coil stack

and wiring and is confident that no fault exists on rod 65 for the components tested. Current traces taken for rod 65 following replacement of the power switch and fuses shows normal values with no evidence of the negative going trace that had been present prior to the coil stack replacement.

Overall, the ERT believes that the Control Element Drive System is ready to support restart. None of the failures associated with the individual control rods would have prevented the safety function of the CEDS which is to insert sufficient negative reactivity to shut down the reactor on demand. The CEDS system does not currently have the desired reliability level to support best-of-best plant operation. The reed relays and the power switches in general have a failure rate high enough to warrant investigation of a design change. St. Lucie, the plant with a CEDS most like the Unit 2 system has had several dropped rods, the cause of which is associated with failures in power switch components. A design change which replaced the reed relay technology with solid state technology would be one example of a design improvement that might yield improvement in reliability. The maintenance that was performed during this shutdown period, reed relay testing and replacement, SCR testing and replacement, fuse upgrades, and rod stroke testing all serve to improve the system reliability. Further improvements in reliability can be achieved through implementation of a Preventative Maintenance program for the CEDS which includes bench testing capability, troubleshooting methodology, and set up methodology prior to power switch installation in the sytem. Bench testing capability will provide a strong benefit in that when power switches are found out of tolerance in the I&C shop, they are either adjusted, repaired, or scrapped, without causing a plant transient or requiring on-line troubleshooting. When the power switches are found out of tolerance in the plant during rod testing, we detect that condition by improper control rod performance.

The last item for consideration would be to minimize system voltage/current transients during startup. Other CE plants use a sequenced electrical startup of the CEDS; MG Sets on line first, Trip Circuit Breakers closed, and the closing the individual Control Element Assemble circuit breakers.

Additional Corrective Action Recommendations from supplemental ERT Summary Report

Corrective Action

Incorporate CE recommendation for sequenced power up of system. MG Sets on line, TCBs closed, then close individual CEA breakers.

Include in the PM program recommended in original summary report guidance for bench testing power switches, adjusting voltage output under

load (may require purchase of test equipment). Recommend minimum of 10% per refuel outage. Provide instructions on as-left state of potentiometer settings to ensure proper voltages are present in system.

Incorporate PM to measure MG set waveform to ensure regulation of the MG unit is proper and there are no spikes in the waveform.

3/6/00

Steve Heard, ERT Lead / Date

PORC MTG 2/3 -00- 0017 2/22/00

1. Description of Event, "Explain What Happened."

Event Description

On February 11, 2000, Operations Surveillance test SP2620A, CEA Partial Movement, was being performed in the Control Room. In this procedure each control rod in turn is inserted five steps, then withdrawn the same five steps to its original position. The reactor was at full power, late in the fuel cycle, and all rods were at the full out position. This test satisfies Technical Specification 4.1.3.1.2, which in turn demonstrates the operability of the control rods. The control rods are tested in the same order as the control rod groups are withdrawn, beginning with the Shutdown banks A and B, then groups 1 through 7.

CEA # 65 has had a history of previous problems. In September, 1999, the rod had dropped, precipitating a plant shutdown. The apparent cause was chafed cables coming from the lower gripper coil stack. This caused a ground, which resulted in large negative currents and a resulting blown fuse. The corrective action was to sheath the chaffed cables. This eliminated most of the negative current indication, and at the time was considered adequate.

Due to this previous problem, I&C had been asked to monitor the test of CEA #65. The surveillance was halted when group 6 had been completed, and Operations waited until I&C was in position to observe. When the test resumed, I&C monitored the test at the cabinets. Group 7 CEAs were tested without incident until CEA #65, the next to last rod in the test. At 1329, when the operator inserted CEA #65, it immediately dropped to the full in position. The immediate cause of the drop was a blown 'B' phase fuse in the power supply. Reactor power decreased in response to the inserted rod. A power reduction was initiated at 1343 to bring the reactor power to 70%, the highest power level at which the rod could be withdrawn with out threatening any power limits.

Earlier in the test sequence, when group 3 was tested, CEA #63 had shown no hint of a problem as it was stepped in and out at 1303. However, either immediately after the last step, or soon thereafter, something caused the high and low voltage relays in the upper gripper 'A' phase power switch to weld shut. This caused the power switch for phase 'A' to remain at full current. The upper gripper coil is the only one of the five coils that is normally energized, so that the closed relays had no immediate effect. However, the continuous high current did exceed the limit of the fuse, and this led eventually to the failure of the 'A' fuse at 1346. This was 43 minutes after CEA #63 had been tested, 27 minutes after CEA #65 had dropped, and three minutes after the reactor downpower had begun.

CEA #63 dropped to the full in position. The operators recognized that with two rods inserted AOP 2556 called for a manual reactor trip, and seven seconds later, after verifying the condition, the reactor operator initiated a manual reactor trip.

2. Historic review, "Explain when it happened before and what corrective actions were taken."

September of 1999 CEA 65 dropped. Current traces identified a definite ground. This was traced to a chafed wire at the head. An insulating sleeve was installed. The phase 'A' and 'C' 15 amp fuses were also replaced. Current traces taken after these repairs did not match ideal traces. Some negative dips were identified in both the withdrawal and insert sequence. CE, Dave Story, was enlisted to evaluate the traces. Considering the traces he recommended that once the rod was in position not to move it. Leaving the rod stationary once withdrawn could not be accomplished, Technical Specification Surveillance Requirements require monthly rod motion of any not fully inserted control rod to ensure rods are tripable.

~ 2 weeks ago CEA 65 slipped.

3. Analysis, Explain the Failure Mode, How, and determine Why it Happened.

CEA 65 'B' phase 15 amp fuse was found to be blown. There is a question, regarding breaker sizing? Saint Lucie (SL) has 15 amp fuses installed. Each refueling outage SL replaces these 15 amp fuses. They are not experiencing the same number of control rod drops. Other CE designs have eliminated or have never had the 15 amp fuses. An circuit breaker with proper current interruption capability has been provided. The current through the fuses for the upper gripper, lower gripper, and the lift coils exceeds in amplitude the 15 amp fuse rating. The period, amount of time the fuse is exposed to these high currents, is typically too short to cause the fuse to fail for any event of normal duration. The 'B' phase fuse was replaced and a retest attempted. After two steps out the 'B' phase fuse failed. The fuse was replaced. Additionally, this time the Upper Gripper Power Switch and the Pull Down Power Switch were replaced and CEA 65 was withdrawn (8 steps) and inserted twice.

Voltage readings were taken on power supplies, coil impedance was measured and cables were megger checked, these readings were all satisfactory. Technicians replaced phase 'B' 15 amp fuse. When moving the rod to obtain current traces the rod stepped out ~2 steps and 'B' phase 15 amp fuse blew again. The 15 amp 'B' phase fuse, the Pull Down Coil Power Switch and the Upper Gripper Power Switch were replaced. These power switches were replaced based on somewhat unusual current traces on the second step of CEA 65. Following this, CEA 65 was tested twice, 8 steps out and 8 steps in, and current traces were obtained. Although the current traces did not match the ideal traces they do match traces that were obtained in September. CE was previously contacted with respect to the current traces for CEA 65 and attributed the trace to a slight ground in the coil stack for the rod. . No other rods exhibit this negative dip in their current readings.

During this outage this coil stack has been replaced. When the coil stack was replaced for CEA 65 boron was identified on the outer portion of the connector shell. This resulted in additional conduit/cable being replaced. All rods will have current traces obtained prior to restarting the unit as a part of Hot Rod Testing.

With regard to CEA 63, something caused the high and low voltage reed relay contacts in the upper gripper 'A' phase power switch to weld shut either immediately after it's last step during rod control testing or soon thereafter. This caused the Upper Gripper Power Switch for phase 'A' to remain at full current. The continuous high current did exceed the limit of the fuse, and this ultimately led to the failure of the 'A' phase fuse.

This is an excerpt from a letter associated with troubleshooting performed by CE on some failed Maine Yankee Power Switches. "The other component found defective in the power switch modules was the reed relays. In each power switch module, two out of three reed relay contacts were fused together due to arcing. This was also the result of rapid and random cycling of the relay module due to the insufficient operating voltage produced by the defective 15 volt dc logic power supply."

Six years ago MP2 had experienced problems with the 15 volt dc logic power supplies. A subsequent modification (larger current capability supplies) was performed improving the voltage stability and to eliminate end of life issues. Understanding what was discussed above, that the low voltage could cause premature failures of the reed relay contacts, I&C performed power supply voltage checks of all the 15 volt dc logic power supplies, all were satisfactory. In addition I&C is performing contact resistance checks of the reed relay contacts on each of the power switch modules. The low voltage experienced years ago may have left a legacy of high resistance contacts. Pitted high resistance contacts could cause arcing which could lead to overheating and finally fusing of the reed relay contact. A fused reed relay contact was found in the Upper Gripper Power Switch for CEA 63. Two other rods have exhibited this fused reed relay failure mode.

Why do the Upper Gripper Power Switches exhibit more failures than the other 4 power switches? With the rods latched the upper gripper power switch is gated to supply power at reduced current to the upper gripper (stationary) coil which holds the control rod in place. The power switches (upper gripper, lower gripper, load transfer, pulldown, and lift coils) are gated temporarily in both the withdrawal and insertion sequence. The power switches are interchangeable. The current values seen by the upper and lower gripper coils is 20-22 amps for ~ 20 milliseconds, the lift coil sees ~ 40 amps for 20-30 milliseconds. The load transfer and pulldown coils see lower currents. CE has instructed our I&C technicians that if the Upper Gripper develops a problem use the Pulldown module. Due to rod speeds that we have the pulldown coil is not necessary. During this outage CE provided a test and acceptance criteria for the SCRs in the power Switches, a SCR

failing the acceptance criteria may still be functional but is degraded. The SCRs in all power switch modules were tested. The following table provides the results of that testing. Note that the Upper Gripper power switch has one of the highest number of failures to meet acceptance criteria. Note also that a number of unsatisfactory readings were identified in the Pulldown modules. Poor record keeping with rod control problems leads us to presume that these degraded Pulldown modules were once utilized as Upper Gripper Modules and when rod control problems existed they were switched. The Upper Gripper modules see greater duty cycles therefore the Upper Gripper Power Switches appear to be more susceptible to age/duty cycle related failures.

Power Switches with Failed SCR's

CEDM Number	Lift Coil	Upper Gripper	Lower Gripper	Pull-Down	Load Transfer
1					A
2		A			
5	C				
7				B	
9				A	
20				A	B
29	A				
31		A	C		B
43				B	
44		C			
47		C			
54				B	C
63		A			

The letter indicates the phase that was found degraded.

Intermittent failures in the rod control system have historically been corrected by replacing power switches and/or timer modules. These modules have been returned to CE for evaluation repaired without extensive failure mode determination. If the modules are tested at CE and no deficiencies are identified, they are returned to the warehouse to be used as spares. We have not requested any detailed troubleshooting or failure mode determination until recently. The maintenance history is not well documented with respect to what repairs have been made to any particular module and where that particular module has been throughout it's life in the rod control cabinets. Testing spare modules identified 4 SCRs that did not meet the acceptance criteria provided by CE.

MP2, T.S. 3.1.3.1.e with 1 rod misaligned $\geq$ 20 steps reduce thermal power to $\leq$ 70% within one hour. If negative reactivity is required boration shall be used. Then within one hour after reducing thermal power, restore the rod. CE Improved Standard TS were evaluated and it too requires a downpower followed by restoring proper control position. The new Improved Standard TS surveillance

requirement is to once every 92 days, exercise control rods rather than our current rod test every 31 days.

If a fuse blew I&C was not prepared to immediately replace that fuse. The basis for this is that there is no urgency to replace the fuse, as the rod cannot be withdrawn until the plant is at 70% power.

What are the preventive measures (PMs) that MP2 performs for the rod control system. What PMs are MP3 and the industry performing for rod control. One difference is that Westinghouse recommends that the fuses be X-rayed. Another difference is that St. Lucie changes the 15 amp fuses each refueling outage.

4. Recommended Corrective Actions

Remedial

CEA 65:

CEA 63: Replaced the 'A' phase 15 amp fuse. When the trip breakers were closed the fuse immediately blew. This is indicative of a failure in the Upper Gripper Power Switch. The Upper Gripper Power Switch and the 'A' phase 15 amp fuse were replaced. Rod was tested twice, 8 steps out and 8 steps in, obtaining current traces. The current traces closely matched the ideal traces.

Compensatory

Change MP2 T.S. to be able to utilize the extended period for the surveillance test. test every 92 days versus 31 days.

Corrective Action to Prevent Recurrence

Recommend the 15 amp fuses be upgraded to 30 amp fuses. Change the existing fuse blocks to accommodate these larger fuses. Replace the 35 Amp neutral fuses. This action has been completed

Recommend that resistance checks of each SCR in each Power Switch module installed and spares be following the CE guidance . SCRs were tested in both the installed and spare Power Switches using with a Simpson 270 analog Ohmmeter. or its equivalent. Numerous SCRs did not pass the acceptance criteria. These SCRs have been replaced. (Complete)

Recommend installing Power Switch modules with less duty cycle in the Upper Gripper slot location. The Pulldown module Power Switches were switched with the Upper Guide Power Switches. (Complete)

Recommend replacing the coil stack for CEA 65. The coil stack and cable/conduit for CEA 65 was replaced. (Complete)

Test contact resistance for all reed relays. Replace any exhibiting unusually high contact resistance.

Verify setting of the 15 volt dc logic power supply for all CEAs. According to CE. insufficient voltage has resulted in rapid and random cycling of the relay module causing the reed relay contacts to weld closed.

Recommend during the rod motion test. performing data gathering/analysis and

knowing as left condition of each rod prior to moving on to test the next rod. IC2420F

Additional Corrective Action

Obtain current traces on all rods and compared with ideal traces prior to restarting the unit.

Establish a program for periodic refurbishment of Power Switch Modules.

Establish maintenance history control for each CEDM drive in a manner not unlike a loop folder for instrumentation.

Send CEA 65 coil stack to CE for failure mode determination.

Send 15 amp fuses which had been previously installed in the CPP for the CEAs for testing for reduction in rating or other aging/cyclic failure modes.

Evaluate and implement as appropriate the Optimization Strategy for control rod testing in Attachment 1.

5. List of CR number and title of Other Equipment Malfunctions or Human Errors associated with this event.

See attached table of CRs generated which were associated with this event. There were no human performance errors associated with the rod drop.

6. List Personnel Interviewed.

Pete Smith
Boyce Atkinson
Steve Brown
Jim Ritchie
Operating Shift Personnel, personal statements, no additional insight into specific rod drop event.
Steve Nix
Doug Vining

7. Document Reference Material Used.

RP 17 Event review team
MP2 Technical Specification Section 3.1.3.1
MP3 Technical Specification Section 3.1.3.1
OP 2620A
Lesson plan IC 00459T, CEDS
MSEE/DCN

Optimization Strategy To Prevent Future CEA Drops

I. I&C Prestaged Equipment

   A. Diagnostic/Repair Procedure

   B. Astro-Med Recorder

   C. UG Power Switch Parallel Key

   D. CPP Power Supply Voltage Tester (DVM)

   E. 15 amp Main Power Fuses (3)

   F. 6 amp CPP Power Supply Fuses (2)

II. Start test with CEA #65, followed by other "high-risk" CEAs

III. Before each CEA is tested/exercised:

   A. Verify CPP power supply output voltage

   B. Ensure Astro-Med connected and ready to record CPP pulses

IV. If voltage on **both** CPP power supplies test sat., Then proceed with SP-2620A test of applicable CEA

   A. If CPP power supply voltage unsat, adjust power supply voltage and retest/proceed as applicable

V. If Astro-Med indicates improper CPP response during CEA movement, proceed as follows:

   A. DO NOT proceed to next CEA in surveillance

   B. Parallel faulted CEA with counterpart (UG parallel key)

   C. Replace faulted CPP power switches as necessary

   D. Verify 15 amp power fuses NOT blown (**all three** phases)

   E. Unparallel CEAs and retest faulted CEA

   F. If test sat, continue with SP-2620A

CEA 65 Forced Outage Event Review Team Action Plan

Replace rod 65 coil stack.

Shoot / megger rod 65 cable once unhooked at the Hacss to facilitate any needed repairs / replacement.

Upgrade rod control fuses from 15 amps to 30 amp fuses or 30 amp breakers.

The Event Review Team endorses the I & C recommendation to reconfigure the power switches to have the previously continuously energized switches swapped with those not continuously energized.

Analysis

Based on the information currently available, the ERT is unable to determine conclusively the precise failure precipitator. Rod 7-65 appears to have a ground somewhere in the circuit between the cabling and the coil stack. This is indicated by the current transient taken when the rod is withdrawn or inserted.

Rod 3-63 appears to have tripped due to failed relays in the upper gripper circuit. The failure mechanism for the relays is unknown.

There appears to be a relationship between Power Switch failure and fuse failure, most of the failures are paired (fuse and power switch fail concurrently). A low voltage in the Coil Power Programmer Power Supply has been postulated to cause a failure of the reed switch (relay) in the Power Switch as a result of less than full deflection of the reed and subsequent arcing at the contact interface. Any other phenomena which could cause low voltage in the circuit, for example high resistance in the fuse block, could result in accelerated failure of the relay. The above analysis is somewhat anecdotal in nature as there is no apparent hard evidence that supports the "low voltage-relay failure" specific to the CEDS although there is general industry evidence that insufficient pull-in voltage for relays can result in "chattering" and "contact degradation." *Questions out to industry on failures of this type in power switches etc.*

The only major components that have not been replaced in rod 7-65 are the coil stacks and the interposing cable.

I&C Trouble Shooting Activity

1. I&C Technician in Control Room notified that CEA #65 has dropped.
2. I&C Technician contacts the I&C shop and requested additional support.
3. I&C Technician verifies that the Coil Power Programmer (CPP) power supplies are de-energized.
4. I&C Technicians and CBM verified that the 'B' phase fuse for CEDM #65 was open.
5. Unit is Manually tripped prior to fuse replacement due to CEDM #63 dropping.
6. I&C Technician verifies that the 'A' phase fuse for CEDM #63 is open
7. I&C Technician performs Insulation Resistance checks on CEDM #65 wiring, all readings are within allowable values (>100 Meg)
8. I&C Technician performs Resistance checks on CEDM #65 coils, all readings are within allowable values.
9. I&C Technician performs Insulation Resistance checks on CEDM #63 wiring, all readings are within allowable values (>100 Meg)
10. I&C Technician performs Resistance checks on CEDM #63 coils, all readings are within allowable values.
11. Fuse is replaced in the 'B' Phase of CEDM #65.
12. Trip Circuit Breakers are closed
13. CEDM #65 is re-energized and the 'B' Phase Fuse opens immediately.
14. Upper Gripper and Pull-Down Power Switches for CEDM #65 are replaced.
15. Fuse is replaced in the 'B' Phase of CEDM #65.
16. CEDM #65 is withdrawn and inserted. Coil Current traces are taken, coil currents are within nominal range.
17. Pull Down coil current is measured to be approximately 20% less than the previous measurement.
18. Negative going pulse is seen on several traces, Pull down and upper gripper.
19. Fuse is replaced in the 'A' Phase of CEDM #63.
20. CEDM #63 is re-energized and the 'A' phase fuse for CEDM #63 opens immediately.
21. The Upper Gripper power switch is replaced
22. Fuse is replaced in the 'A' phase of CEDM #63
23. CEDM #63 is withdrawn and inserted. Coil Current traces are taken, coil currents are within nominal range.
24. All primary fuses, except for CEDM #63 and 65, are removed from the CEDM cabinets and labeled.
25. Troubleshooting is conducted on failed upper gripper power switch from CEDM #63, the high and low current control relays are found to be welded shut for the 'A' phase.
26. SCR's in failed power switch modules are tested, potentially failed SCR is identified in former CEDM #63 upper gripper power switch.

Historic Rod Problem Areas

7-38

9/23/99	Upper Gripper Power Switch replaced. Blown Phase B fuse, loose conn.
3/15/99	Replace timer module

7-65

4/23/94	UG Power Switch replaced. Logic Power Supply replaced
6/17/94	UG Power Switch replaced
4/28/99	Blown Fuses (Unknown)
5/9/99	All Power Switches replaced, (5)
9/17/99	Coil Ground, sleeved and shrink tubed
9/22/99	Blown fuses, replaced
1/29/99	Slipping, exercised. no repair
2/12/99	Phase B fuse blown. replaced fuse and Pull Down Power Switch

6-17

1/8/93	Pull Down Power Switch replaced
3/15/99	Replaced timer module

5-5

1/11/91	Voltage adjusted up

3-60

4/99	UG Power Switch
5/28/99	Lift Coil Power Switch

3-63

2/11/00	UG Power Switch, Phase A fuse replaced

2-18

12/14/95	UG, Lift power switches replaced, Fuses replaced (Unknown)

2-22, 2-23

1988	Boron overheat replace some parts.

1-27

1/93	Blown fuse,
9/17/99	LG Power Switch

1-30

8/3/95	Logic power supply replaced
9/17/99	Blown phase B fuse

A-44

6/82	Loose Connection
8/1/95	Blown phase A fuse

A-49

9/22/99	Blown phase C fuse, unknown blown fuse.

Mr. Albert

May ii,
NOME-94-N

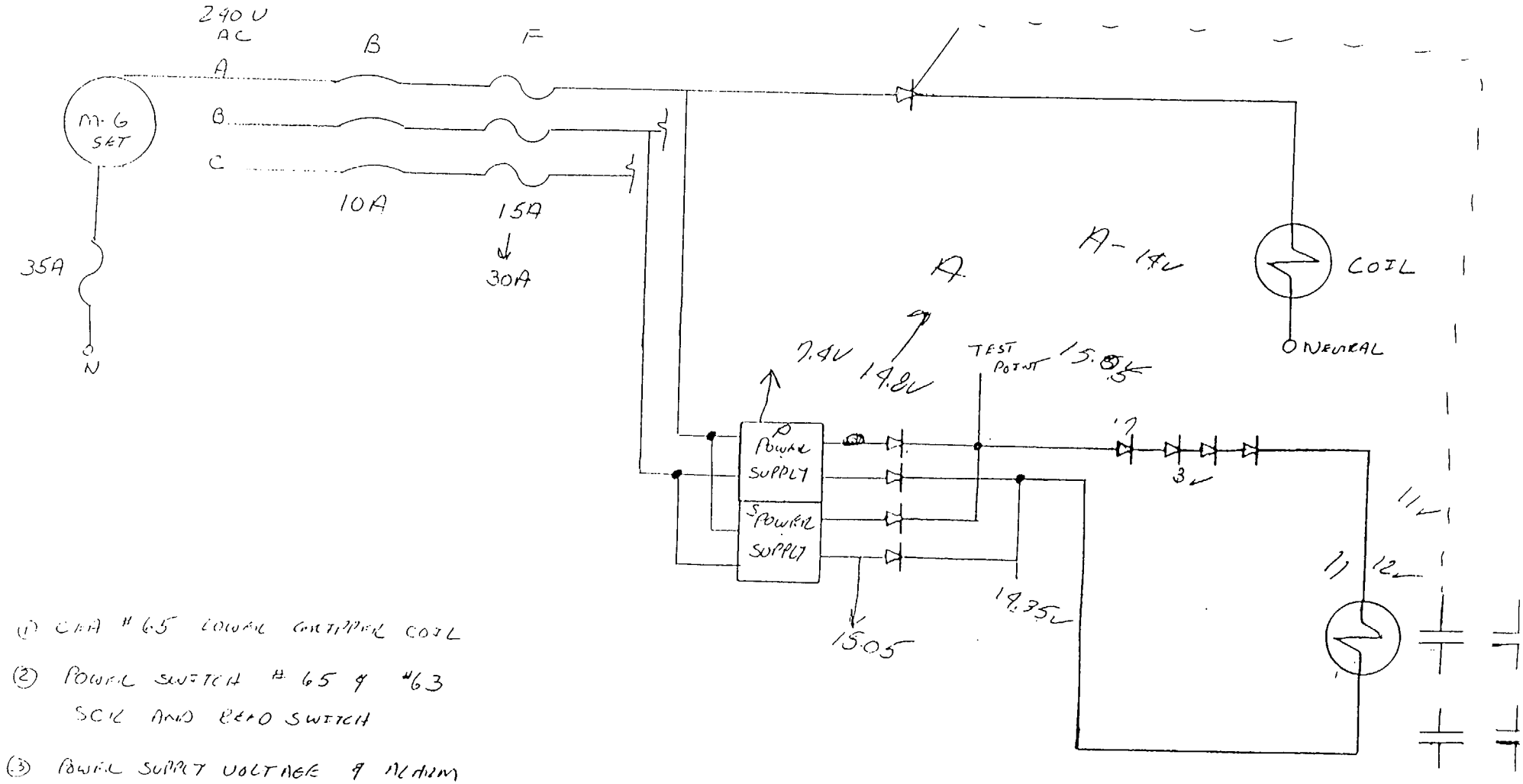
There are two reed relay modules inside each power switch, with three individual reed switch contacts inside. The two reed relay modules switch the three SCR's located in the power switch module on and off when selected by the timer module. The reed relays require nominal 12 volts dc to create a sufficient magnetic field strong enough to simultaneously close the three individual reed switch contacts inside. The required 12 volts is derived from the 15 volt dc logic power supply via four dropping diodes in the CPP timer module. When the two relay modules in each power switch are energized by 12 volts dc they simultaneously switch a voltage signal to the SCR gate circuit turning on the three SCR's. When the 12 volts is removed from the two relay modules the reed switch contacts open removing the gate voltage signal from the SCR gate circuit and the SCR's turn off. This sequence is controlled by the CPP timer module. When the timer module is in the stationary or hold mode of operation a steady 12 volts dc is supplied to the relay module in the upper gripper power switch maintaining the control rod in the withdrawn position. However, if the voltage to the relay module coil is at or just below the minimum voltage required to operate, (approximately 10 volts) the relay coils magnetic field strength will not be sufficient to hold all three reed switch contacts closed. The field strength at the time may only be sufficient to hold two relay contacts firmly closed with the third contact operating, intermittently switching the 5CR on and off rapidly. This problem will randomly change to the other two relay contacts and in turn to the other two SCR's while the power supply voltage remains around the minimum operating voltage of the reed relays. The random and rapid switching on and off of the SCR's over a period of hours creates excessive heat within the SCR at the cathode to anode junction. The excessive heat breaks down the junction area between the SCR's anode and cathode creating an internal short circuit forcing the SCR to remain energized continuously. This type of failure was found in the upper gripper, lower gripper and pulldown power switches removed from Maine Yankee. The other component found defective in the power switch modules was the reed relays. In each power switch module, two out of three reed relay contacts were fused together due to arcing. This was also the result or rapid and random cycling of the relay module due to the insufficient operating voltage produced by the defective 15 volt dc logic power supply

Either of the two failures mentioned were sufficient to keep the grippers engaged against the drive shaft and prevent the movement of the Control Element: Assembly (CEA).

In conclusion, I recommend you replace the upper gripper power switch module for CEA No. 65. and adjust all your power supply outputs to ±15 volts dc +0.1vdc/-0.0vdc If you have any further questions, please feel free to call me at (203) *285-3065.*

Sincerely, ABB
COMIBUSTION
ENGINEERING
NUCLEAR

OPERATIONS
David A. Story



(1) CAA #65 LOWAL GRIPPER COIL

(2) POWER SWITCH #65 & #63
SCR AND REED SWITCH

(3) POWER SUPPLY VOLTAGE & MEASUREMENT

The ERT provided a single reed switch (discolored, apparently oxidized) to the chemistry department. An experiment was performed to determine if that reed switch had lost vacuum. The reed switch placed in a vacuum chamber in a flask of water. A hard (25" Hg) vacuum was drawn on the flask and maintained for two hours. At the end of abut two hours, the vacuum was broken with the reed switch under water. The switch was left in the water for about two hours and then inspected for water intrusion. No water was noted, QED, the switch remains hermetically sealed.

I&C disassembled two reed relays which had good and high resistance contacts. Visual observation did not identify any significant difference in a high contact resistance reed switch versus a low contact resistance reed switch. I&C then performed bench testing of removed reed switch relays. The coil voltage applied was 12VDC, which is adequate to maintain the contacts in a closed state. While testing the bench surface was tapped, surprisingly the contact resistance changed. I&C said one of these test resulted in the contact resistance going to full open. The DMM supplies minimum voltage/current through the contact to measure the resistance. Therefore the failure initiator appears to be the mechanical shock applied when tapping the bench top.

Failure modes of the CPP Power Switch

There are three major components which can fail within the Power Switch which can result in a rod slip or a rod drop. The failures may also result in fuse opening or breaker action.

Each power switch contains three power SCRs, three pilot SCRs, six reed relay contacts (three low power and three high power) and six wire wound potentiometers.

If a potentiometer fails, it will usually short to ground which will blow the fuse or breaker for the affected phase of power. When the potentiometer fails it will short to the chassis(which is grounded) which will cause a voltage spike across the affected reed contact thus fusing or 'bridging' the reed contact. The potentiometer should be changed. The reed contacts should be checked to determine proper status (not fused). The SCRs in the circuit should be checked and any faulted ones should be replaced.

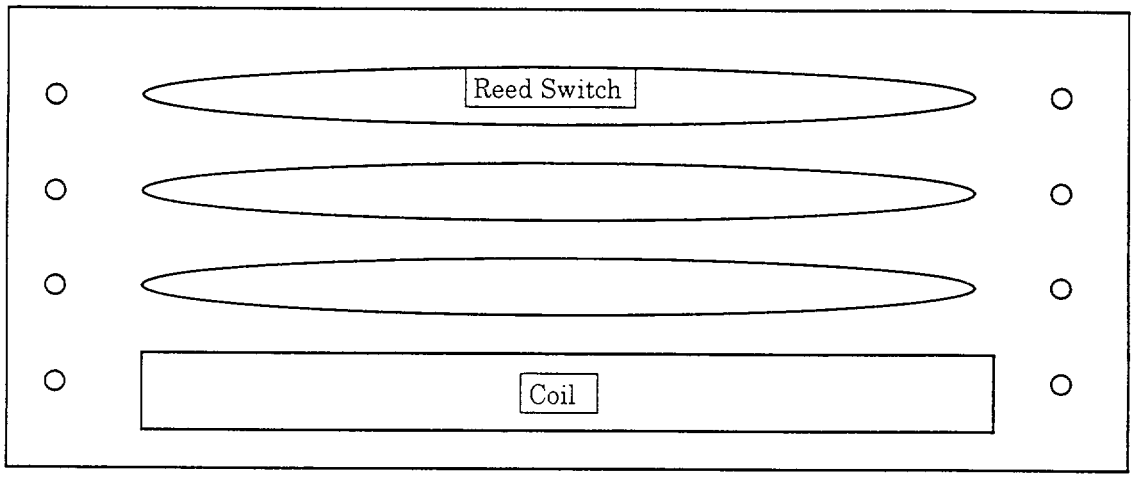
If the potentiometer is found bad and the SCR and reed contact are not checked, the power switch is likely to cause another fuse actuation or breaker trip.

The reed contracts within the power switch are very sensitive. If a high resistance is found across an energized closed contact, a slight bump will cause the reed contact to clear or have a very low resistance.

During rod testing following SCR testing and replacement and Reed Relay testing and replacement, a number of rods exhibited problems ranging from failure to move on demand to blown fuses to tripped circuit breakers. The rods and associated failures are detailed in the following table.

Rod #	Symptoms	Action	Comments
CEA 3 (PMT)	Trace improper and could not be adjusted (ran out of pot)	Swapped pull down and upper gripper power switches and problem corrected. Later, a good switch was inserted in the pull down slot.	The 'bad' power switch was sent to CE for testing and repair. No repair required. CE was able to adjust power supply to proper value.
CEA 47 (PMT)	Rod did not move with group. Traces indicate good power switch & coil integrity	Verify coil stack alignment (circuit breaker presently open) Voltage set too low.	The only problem was that voltage was set too low to develop a proper signal to the coils to lift the rod. Corrected on-site.
CEA 65 (PMT)	Blown B phase fuse, circuit breaker tripped.	Power switches removed and tested one at a time. Bad lower gripper power switch.	This rod has had the same power switches since 9/99. Possible fault in coil stressed power switch causing premature failure.
CEA 40 (PMT)	Tripped circuit breaker.	Replaced lower gripper power switch. Tested sat	Power switch sent to CE for testing. Other than having to adjust voltage, no problem noted with lower gripper power switch
CEA 41 (PMT)	Rod failed to move.	Bad Lift power switch, replaced tested sat.	No additional action.
CEA 49 - No MNTC performed. no reed relays or SCRs replaced	Blew "C" phase fuse	Replaced fuse. Power switches tested sat. Indicative of some non-repeatable fault somewhere in the system.	CEA 49 has blown 'C' phase fuse before. Fuse replaced, no repair activity. Recommend coil stack replacement during upcoming outage.
CEA 63	Original Upper Gripper blowing "A" phase fuse	Unknown cause	CE tested and determined there was a shorted potentiometer on the Upper Gripper LO current power supply, Phase "A"
CEA 64	Lower Gripper not engaging, rod not moving	Unknown cause. Lower gripper power switch replaced	CE tested and determined voltage was out of adjustment.
CEA 23	Noise on pulldown trace.	Bad pull down power switch; replaced	No additional action.

Glass case, vacuum, reed relay contact.
No voltage rating make and break 3
Amps DC and will carry 5 Amps DC,
1000VDC interrupt, contact interrupt
rating of 50 Watts of a Tungsten Load.
New Product Engineering
760-1-2 K2
Wabash, IND.



ECAD has performed testing of cables to determine location of any existing faults. Cables for CEA 65 and CEA 49 were tested with no detection of any faults.

One additional difference noted in how we operate the system and how other similar vintage CE plants operate is that Calvert Cliffs powers up the system from the MG Sets by first closing the Reactor Trip Breakers (TCB) then closing individual CEA breakers. Millstone's practice is to close the CEA breakers then close the TCBs. Combustion Engineering recommended that Millstone change this practice to close the TCBs then close each CEA breaker. This applies load to the MG set in smaller increments. This will eliminate potential spikes on the MG set.

Conclusion of supplemental ERT Investigation

Of all the 'failures' noted during rod testing following SCR and Reed Relay replacement, all except one is attributable to identified system deficiencies which might reasonably be expected to occur following extensive maintenance activities in the CPP cabinets. The original (from the trip) Rod 63 power switch was determined at CE to have a faulted potentiometer: Rod 3, 61, 64, and 40 all required voltage adjustments to enable the power switches to function properly, no other faults were found at CE. Rod 41 was determined to have a bad power switch which was replaced. Rod 49 is the only rod which is identified as having future problem potential at a higher rate than the other rods. This rod has tripped the 'C' phase before and subsequent testing failed to determine any fault. When the 'C' phase fuse blew during testing on 2/17, no fault was detected, the fuse was replaced and the rod performed perfectly. Rod 49 has not exhibited any tendency to slip but it has failed to move. If the 'C' phase fuse is the only fuse that blows, a dropped rod should not result as the logic power supplies will continue to function.

Additional Recommendations from supplemental ERT Summary Report

Corrective Action

Incorporate CE recommendation for sequenced power up of system. MG Sets on line, TCBs closed, then close individual CEA breakers.

Include in the PM program recommended in original summary report guidance for bench testing power switches, adjusting voltage output under load (may require purchase of test equipment). Recommend minimum of 10% per refuel outage. Provide instructions on as-left state of potentiometer settings.

Incorporate PM to measure MG set waveform to ensure regulation of the unit is proper and there are no spikes in the waveform.

Prinicipies of Electromechanical Relay Operation

3.32 Reed and Mercury Wetted Relays

The magnetic reed switch was originally developed in the early 1940s, however, there was no commercial demand at the time since high reliability, extremely fast operation, and long life were not considered as important as they are today. The combination of lack of knowledge and lack of necessity caused this new switching concept to remain relatively unnoticed by the engineering world until the mid-1050s.

As manufacturing techniques improved the advantages of reed switches gained wide recognition, the reed relay industry grew by leaps and bounds. Hermetically sealed contaces in a clean atmosphere are unaffected by dust, corrosion, or oxidation, and design allows no opportunity for sticking, binding, or wearing of hinged joints. With proper circuitry, magnetic reed switches can offer a life span in excess of 100 million operations. Although slower than transistorized logic, reed relays are sufficiently faster than conventional relays, which allows their use in high speed switching applications. The reed relay provides package density which approaches that of its solid state counterpart, but is far greater than is available with convention relays. When compared to transistorized logic, the necessary coupling circuitry between the logic and input and output devices is less complicated and less expensive.

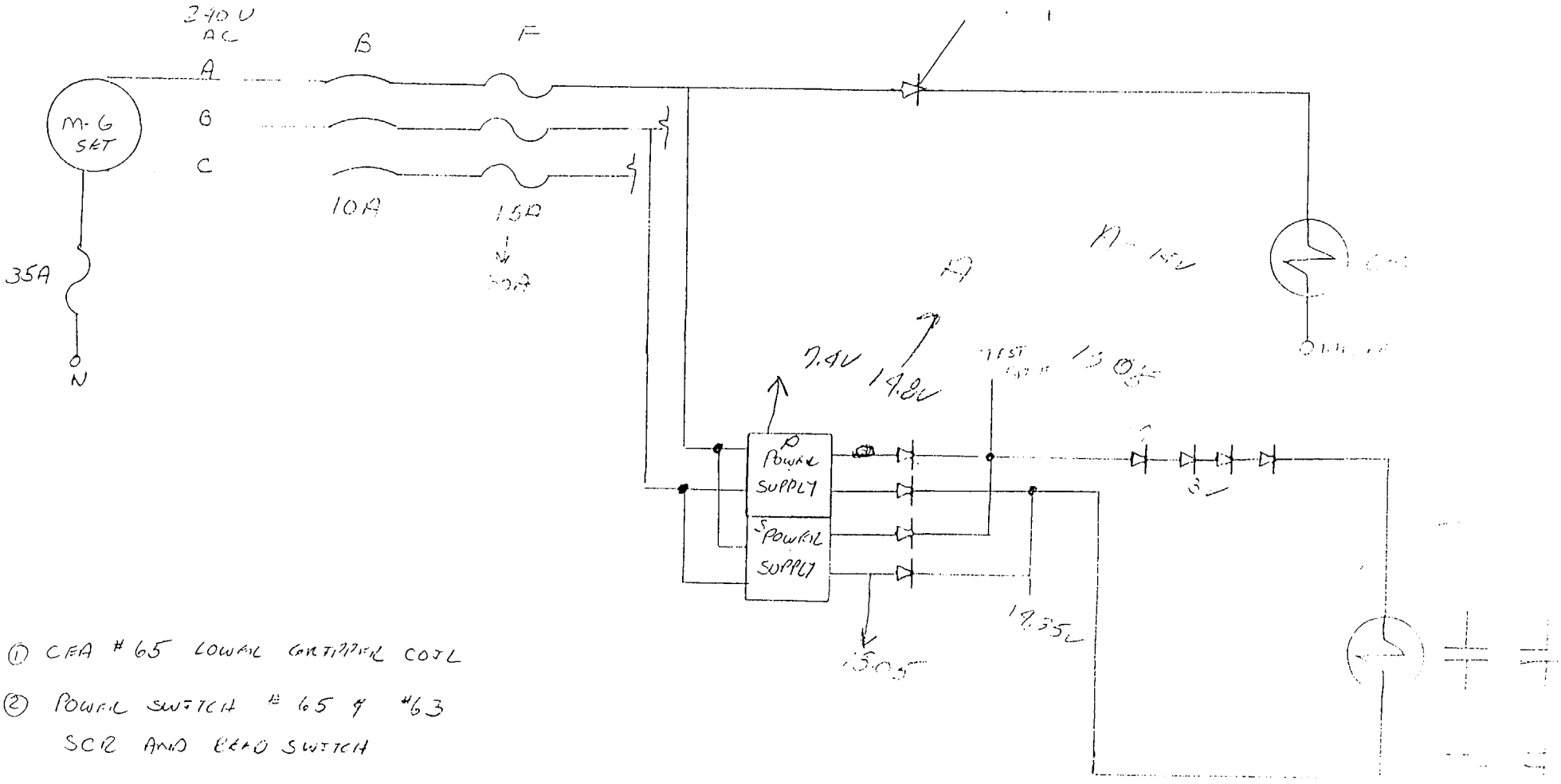
The principle of operation is fairly simple. A basic magnetic reed switch consists of a pair of low reluctance, ferromagnetic, slender flattened reeds, hermetically sealed into a glass tube with a controlled atmosphere in cantilever fashion so that the ends align and overlap-but with a smaller air gap.

Since the reeds are ferromagnetic, the extreme ends will assume opposite magnetic polarity when brought into the influence of a magnetic field. When the magnetic flux density is sufficient, the attraction forces of the opposing magnetic poles overcomes the reed stiffness causing them to flex toward each other and make contact. This operation can be repeated millions of times at extremely high speeds.

Energizing the coil sets up a magnetic field which acts in the same manner as the permanent magnet in the case above. A form "B" (normally closed) contact arrangement is made by placing a permanent magnet adjacent to form "A" (normally open), reed switch, thus closing it. Energizing the coil surrounding the switch and magnet cancels out the permanent magnet to open the switch, when the proper coil voltage polarity is applied.

Mercury wetted capsules are similar to dry reed switches in that the mechanical elements are ferromagnetic reed enclosed in a hermetically sealed glass envelope. A small amount of mercury is placed in the glass capsule prior to sealing it. The mercury wets the contact surfaces and provides a new and clean contact surface at every operation due to the capillary action of the liquid mercury.

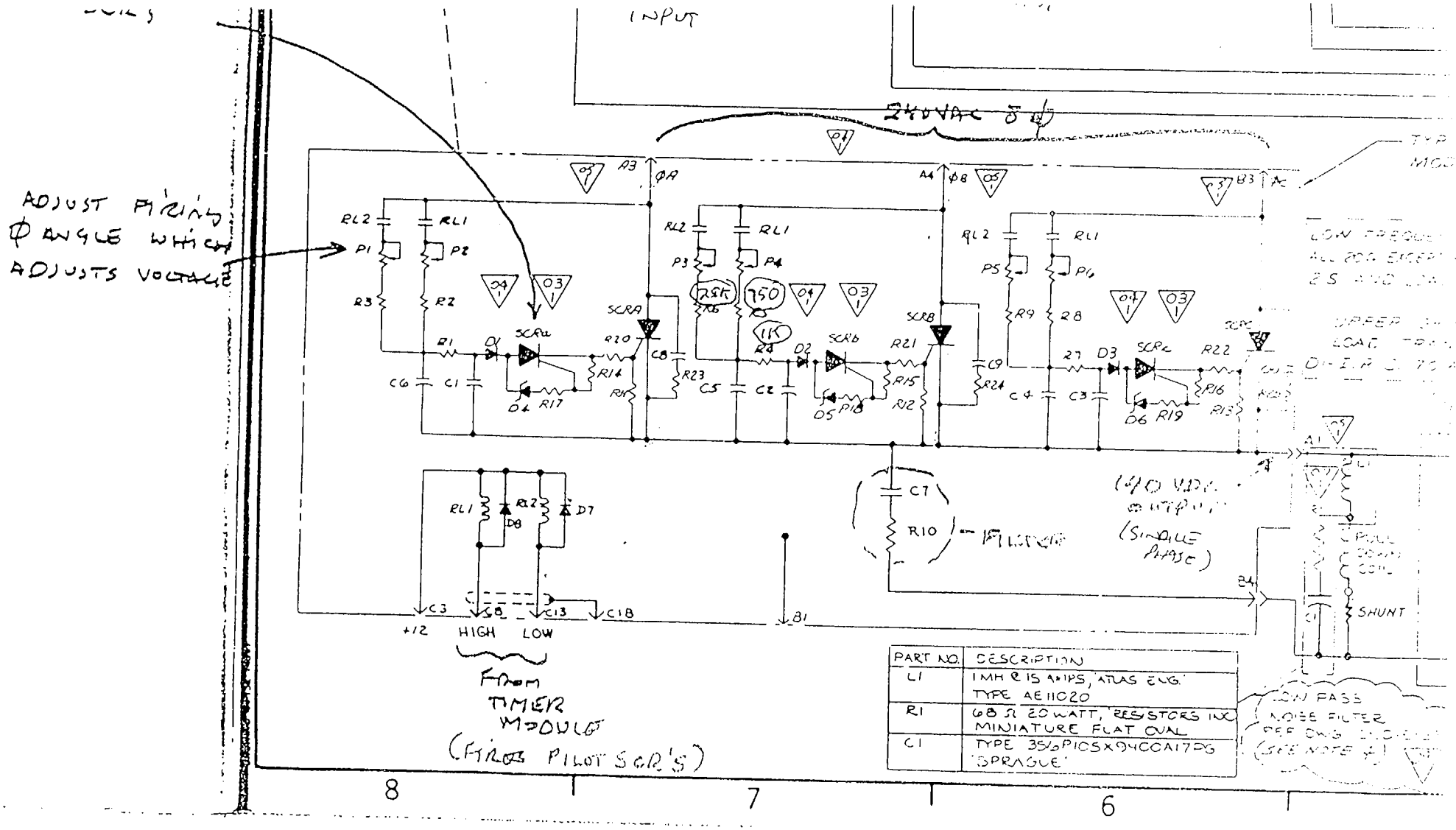
Further information relative to reed relays may be found in Chapters 12 and 13.



① CFA #65 LOWAL CONTAPPER COIL

② POWAL SWITCH #65 & #63
SCR AND EEAO SWITCH

③ POWAL SUPPLY VOLTAGE & MEANING



PART NO.	DESCRIPTION
L1	1MH @ 15 AMPS, ATLAS ENG. TYPE AE11020
R1	68 Ω 20 WATT, RESISTORS INC MINIATURE FLAT OVAL
C1	TYPE 35/6P105X94C0A17PG 'SPRAGUE'

Event Description

On February 11, 2000, Operations Surveillance test SP2620A, CEA Partial Movement, was being performed in the Control Room. In this procedure each control rod in turn is inserted five steps, then withdrawn the same five steps to its original position. The reactor was at full power, late in the fuel cycle, and all rods were at the full out position. This test satisfies Technical Specification 4.1.3.1.2, which in turn demonstrates the operability of the control rods. The control rods are tested in the same order as the control rod groups are withdrawn, beginning with the Shutdown banks A and B, then groups 1 through 7.

CEA # 65 has had a history of previous problems. In September, 1999, the rod had dropped, precipitating a plant shutdown. The apparent cause was chafed cables coming from the lower gripper coil stack. This caused a ground, which resulted in large negative currents and a resulting blown fuse. The corrective action was to sheath the chaffed cables. This eliminated most of the negative current indication, and at the time was considered adequate.

Due to this previous problem, I&C had been asked to monitor the test of CEA #65. The surveillance was halted when group 6 had been completed, and Operations waited until I&C was in position to observe. When the test resumed, I&C monitored the test at the cabinets. Group 7 CEAs were tested without incident until CEA #65, the next to last rod in the test. At 1329, when the operator inserted CEA #65, it immediately dropped to the full in position. The immediate cause of the drop was a blown 'B' phase fuse in the power supply. Reactor power decreased in response to the inserted rod. A power reduction was initiated at 1343 to bring the reactor power to 70%, the highest power level at which the rod could be withdrawn with out threatening any power limits.

Earlier in the test sequence, when group 3 was tested, CEA #63 had shown no hint of a problem as it was stepped in and out at 1303. However, either immediately after the last step, or soon thereafter, something caused the high and low voltage relays in the upper gripper 'A' phase power switch to weld shut. This caused the power switch for phase 'A' to remain at full current. The upper gripper coil is the only one of the five coils that is normally energized, so that the closed relays had no immediate effect. However, the continuous high current did exceed the limit of the fuse, and this led eventually to the failure of the 'A' fuse at 1346. This was 43 minutes after CEA #63 had been tested, 27 minutes after CEA #65 had dropped, and three minutes after the reactor downpower had begun.

CEA #63 dropped to the full in position. The operators recognized that with two rods inserted AOP 2556 called for a manual reactor trip, and seven seconds later, after verifying the condition, the reactor operator initiated a manual reactor trip.

I&C Trouble Shooting Activity

1. I&C Technician in Control Room notified that CEA #65 has dropped.
2. I&C Technician contacts the I&C shop and requested additional support.
3. I&C Technician verifies that the Coil Power Programmer (CPP) power supplies are de-energized.
4. I&C Technicians and CBM verified that the 'B' phase fuse for CEDM #65 was open.
5. Unit is Manually tripped prior to fuse replacement due to CEDM #63 dropping.
6. I&C Technician verifies that the 'A' phase fuse for CEDM #63 is open
7. I&C Technician performs Insulation Resistance checks on CEDM #65 wiring, all readings are within allowable values (>100 Meg)
8. I&C Technician performs Resistance checks on CEDM #65 coils, all readings are within allowable values.
9. I&C Technician performs Insulation Resistance checks on CEDM #63 wiring, all readings are within allowable values (>100 Meg)
10. I&C Technician performs Resistance checks on CEDM #63 coils, all readings are within allowable values.
11. Fuse is replaced in the 'B' Phase of CEDM #65.
12. Trip Circuit Breakers are closed
13. CEDM #65 is re-energized and the 'B' Phase Fuse opens immediately.
14. Upper Gripper and Pull-Down Power Switches for CEDM #65 are replaced.
15. Fuse is replaced in the 'B' Phase of CEDM #65.
16. CEDM #65 is withdrawn and inserted, Coil Current traces are taken, coil currents are within nominal range.
17. Pull Down coil current is measured to be approximately 20% less than the previous measurement.
18. Negative going pulse is seen on several traces, Pull down and upper gripper.
19. Fuse is replaced in the 'A' Phase of CEDM #63.
20. CEDM #63 is re-energized and the 'A' phase fuse for CEDM #63 opens immediately.
21. The Upper Gripper power switch is replaced
22. Fuse is replaced in the 'A' phase of CEDM #63
23. CEDM #63 is withdrawn and inserted, Coil Current traces are taken, coil currents are within nominal range.
24. All primary fuses, except for CEDM #63 and 65, are removed from the CEDM cabinets and labeled.
25. Troubleshooting is conducted on failed upper gripper power switch from CEDM #63, the high and low current control relays are found to be welded shut for the 'A' phase.
26. SCR's in failed power switch modules are tested, potentially failed SCR is identified in former CEDM #63 upper gripper power switch.

Historic Rod Problem Areas

7-38

9/23/99	Upper Gripper Power Switch replaced, Blown Phase B fuse, loose conn.
3/15/99	Replace timer module

7-65

4/23/94	UG Power Switch replaced, Logic Power Supply replaced
6/17/94	UG Power Switch replaced
4/28/99	Blown Fuses (Unk)
5/9/99	All Power Switches replaced, (5)
9/17/99	Coil Ground, sleeved and shrink tubed
9/22/99	Blown fuses, replaced
1/29/99	Slipping, exercised, no repair
2/12/99	Phase B fuse blown, replaced fuse and Pull Down Power Switch

6-17

1/8/93	Pull Down Power Switch replaced
3/15/99	Replaced timer module

5-5

1/11/91	Voltage adjusted up

3-60

4/99	UG Power Switch
5/28/99	Lift Coil Power Switch

3-63

2/11/00	UG Power Switch, Phase A fuse replaced

2-18

12/14/95	UG, Lift power switches replaced, Fuses replaced (Unk)

2-22, 2-23

1988	Boron overheat replace some parts.

1-27

1/93	Blown fuse.
9/17/99	LG Power Switch

1-30

8/3/95	Logic power supply replaced
9/17/99	Blown phase B fuse

A-44

6/82	Loose Connection
8/1/95	Blown phase A fuse

A-49

9/22/99	Blown phase C fuse, unk blown fuse.

Analysis

Based on the information currently available, the ERT is unable to determine conclusively the precise failure precipitator. Rod 7-65 appears to have a ground somewhere in the circuit between the cabling and the coil stack. This is indicated by the current transient taken when the rod is withdrawn or inserted.

Rod 3-63 appears to have tripped due to failed relays in the upper gripper circuit. The failure mechanism for the relays is unknown.

There appears to be a relationship between Power Switch failure and fuse failure, most of the failures are paired (fuse and power switch fail concurrently). A low voltage in the Coil Power Programmer Power Supply has been postulated to cause a failure of the reed switch (relay) in the Power Switch as a result of less than full deflection of the reed and subsequent arcing at the contact interface. Any other phenomena which could cause low voltage in the circuit, for example high resistance in the fuse block, could result in accelerated failure of the relay.

The only major components that have not been replaced in rod 7-65 are the coil stacks and the interposing cable.

Optimization Strategy To Prevent Future CEA Drops

I. I&C Prestaged Equipment

   A. Diagnostic/Repair Procedure

   B. Astro-Med Recorder

   C. UG Power Switch Parallel Key

   D. CPP Power Supply Voltage Tester (DVM)

   E. 15 amp Main Power Fuses (3)

   F. 6 amp CPP Power Supply Fuses (2)

II. Start test with CEA #65, followed by other "high-risk" CEAs

III. Before each CEA is tested/exercised:

   A. Verify CPP power supply output voltage

   B. Ensure Astro-Med connected and ready to record CPP pulses

IV. If voltage on **both** CPP power supplies test sat., Then proceed with SP-2620A test of applicable CEA

   A. If CPP power supply voltage unsat. adjust power supply voltage and retest/proceed as applicable

V. If Astro-Med indicates improper CPP response during CEA movement, proceed as follows:

   A. DO NOT proceed to next CEA in surveillance

   B. Parallel faulted CEA with counterpart (UG parallel key)

   C. Replace faulted CPP power switches as necessary

   D. Verify 15 amp power fuses NOT blown (**all three** phases)

   E. Unparallel CEAs and retest faulted CEA

   F. If test sat, continue with SP-2620A

1/1/00

07/14/99 — Approval Date

000101013117

07/21/99 — Effective Date

AR No.

CR Form
Initiation

CR **M2-99-3330**

Section 1: To be completed by initiator (please type or print)

Organization identifying condition:	Discovery date: **12/31/99**	Affected Unit(s):	System #: **2349B**
IT	Discovery time: **1920**	1☐ 2☒ 3☐ C☐	

1. Condition description (including how condition was discovered, organization creating condition, what activity was in progress when event was discovered):

During GMT rollover checks of the PPC it was observed that the C-point time averages for the MET TOWER were not updating.

Continuation Sheet ☐

Component ID.: Source Document:
Method of Discovery: Self
(RP 4, Att. 1)

2. Immediate corrective action taken

Notified Unit 2 Operations, determined affected functions, then remediated the problem (20:51). This problem was determined to be due to a defective LEAP YEAR calculation. Met tower averages and CTMT radiation 10 minute averages on the RCS Leak Rate report were affected by the defective calculation.

TR# AWO# Continuation Sheet ☐

3. Recommended corrective action

Problem has been corrected.

Continuation Sheet ☐

4. Initiator Requests Follow-up: ☐ Y ☒ N

Initiator Name: **James Themig** Time: **0122** Phone No.: **5069**

Initiator's Signature: James E Themig Date: **1/1/00** Cost Control Center **031**

If issue is a nonconforming condition requiring RP 4-8 Condition Report Engineering Disposition, enter the name and department of the individual performing the disposition. / Name / Dept. (1) (2) (3)

Supervisor Name: Mike Weise Time: 0133

Supervisor Signature: M Weise Date: 1/1/00 Phone No: 4352

Section 2: To be completed by Operability/Reportability Screening Designee

1. Does CR have an actual or potential effect on plant or personnel safety, operability, reportability, reactivity management or plant operation?

☐ Yes or Don't Know
☒ No

If yes, describe reason: (1)

Designee: [signature] Date: 01/01/00 Time: 0135

If continuation sheets (RP 4-1, Page 7) are required, identify the section being continued by section number.

ITEM # 4

Form RP4-1
Rev. 7 Chg 3
Page 1 of 7
Sheet 1

A/2

1/6/00

07/14/99
Approval Date

000105170237

07/21/99
Effective Date

AR No.

CR Form
Initiation

CR **M3-00-0055**

Section 1: To be completed by initiator (please type or print)

Organization identifying condition:	Discovery date: **12/30/99**	Affected Unit(s):	System #: **N/A**
Safety Analysis	Discovery time: **1600**	1☐ 2☐ 3☐ C☒	

1. Condition description (including how condition was discovered, organization creating condition, what activity was in progress when event was discovered):

The PRA Section was performing its routine evaluation of the week ahead work schedule for MP3 when EOOS flagged year 2000 date errors. Upon further investigation it was discovered that computer code EOOS requires 4-digit year input after year 2000 to operate correctly.

Continuation Sheet ☐

Component ID.: **N/A**
Method of Discovery: Self
(RP 4, Att. 1)

Source Document: **N/A**

2. Immediate corrective action taken

Computer code EOOS was immediately shutdown before year 2000 arrived. The work scheduling group was notified as to the requirement for 4-digit year input to EOOS. In addition, the software vendor was contacted for any further information related to this problem.

TR# **N/A** AWO# **N/A** Continuation Sheet ☐

3. Recommended corrective action

Work scheduling computer code Primavera needs to output 4-digit year dates from now on which will be used in the input to the EOOS computer code. The software vendor will coordinate with the PRA group the new input data format into EOOS.

Continuation Sheet ☐

4. Initiator Requests Follow-up: ☒ Y ☐ N

Initiator Name: **John Caivano** Time: **1630** Phone No.: **2318**

Initiator's Signature: John Caivano Date: **1/5/00** Cost Control Center **85H**

If issue is a nonconforming condition requiring RP 4-8 Condition Report Engineering Disposition, enter the name and department of the individual performing the disposition. /
Name / Dept.

Supervisor Name: **Yehia Khalil** Time: **1700**

Supervisor Signature: Yehia F. Khalil Date: **1/5/00** Phone No: 0443

Section 2: To be completed by Operability/Reportability Screening Designee

1. Does CR have an actual or potential effect on plant or personnel safety, operability, reportability, reactivity management or plant operation?

☐ Yes or Don't Know
☒ No

If yes, describe reason:

Paul B. Allen — Designee | 1/6/00 — Date | 10:05 — Time

If continuation sheets (RP 4-1, Page 7) are required, identify the section being continued by section number.

ITEM # 2

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Rev. 7 Chg 3
Page 1 of 7

A/3

1/7/00

Signature on file	10/21/98	10/30/98	98-60
Form Approved by	Approval Date	Effective Date	SORC Mtg. No.

AR No.	CR Form Initiation	CR N	CR M3-00-0071

Section 1: To be completed by initiator (please type or print)

Organization identifying condition: **Station Chemistry**	Discovery date: **1/3/00** Discovery time: **1300**	Affected Unit(s): 1☐ 2☐ 3☐ C☒	System #: **N/A**

1. Condition description (including how condition was discovered, organization creating condition, what activity was in progress when event was discovered):

While attempting to validate data in Chemistry Data Management System (WinCDMS), primary systems chemist discovered a bug in the program. The glitch didn't allow him or anyone to validate only data, in the data base, with a sample date before 1/1/00 entered into the system after 1/1/00. Further investigation showed that plotting, data queries and scheduling modules were also effected. This problem also inhibits other groups from looking at the described data.

Continuation Sheet ☐

Component ID.: **N/A** Source Document: **N/A**
Method of Discovery: Event
(RP 4, Att. 1)

2. Immediate corrective action taken

The program supplier, GCR Associates, was contacted.

TR# **N/A** AWO# **N/A** Continuation Sheet ☐

3. Recommended corrective action

The program supplier sent a program fix to the station on 1/5/00. Computer Services has been requested to assist Station chemistry in loading the files to remedy the glitches. All users of the program will then need to reload the application from "Millstone Applications."

Continuation Sheet ☐

4. Initiator Requests Follow-up: ☐ Y ☒ N

Initiator Name: **Michael Roche** Time: **0830** Phone No.: **4406**

Initiator's Signature: Michael Roche Date: 1/6/00 Cost Control Center **842C**

Engineering Disposition: Y ☐ N ☒ Requested Name/Dept. of Dispositioning Engineer: _____ Name/Dept. (1) (2)

Supervisor Name: **David Peiffer** Time: 1430

Supervisor Signature: M. Roche for D. Peiffer per telecon Date: 1/6/00 Phone No: 4616

Section 2: To be completed by Operability/Reportability Screening Designee

1. Does CR have an actual or potential effect on plant or personnel safety, operability, reportability, reactivity management or plant operation?

☐ Yes or Don't Know
☒ No

If yes, describe reason: (1)

Mark Hulto 1-7-00 0200
Designee 1/8/00 Date 0130 Time

If continuation sheets (RP 4-1, Page 7) are required, identify the section being continued by section number.

ITEM # 3

Form RP4-1
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Sheet 1

A/4

DRAFT

Event Review Team Report

Unit 2 SG Level Manual Reactor Trip
January 27, 2000

Team Lead: Rick Bonner
Member: Debbie Godinez
Member: Eric Dean
Member: Al Briggs
Member: Tim Grilley
Member: Will Hayward
Member: Steve Heard

Ad Hoc Member: Pat Dillon
Ad Hoc Member: Howard Duffy
Ad Hoc Member: Marty Van Haltern

ITEM # 5 A/5

27

DRAFT

Unit 2 SG Level Manual Reactor Trip, January 27, 2000

On January 27, 2000 at 1427, a manual reactor trip was initiated due to a drop in Steam Generator level to approximately 57% and the trip of a SGFP. This loss of SG level occurred following feedwater heater oscillations and loss of all heater drain pump flow.

The plant responded normally with minor exception. Each of the exceptions were addressed as individual CRs or as part of this investigation. The post trip response review was presented to PORC by the Unit Duty Officer including any abnormal system response. All safety related equipment performed as expected and the plant was stabilized at normal post trip parameters. All procedurally required actions were accomplished. The operating shift performed all expected actions and evidence of conservative decision making was noted in the decision to manually trip the reactor in light of the observed transient.

Summary Sequence of Events on January 27

- ~ 0830 the 2A Feedwater Heater sight glass was returned to service after leak repair.
- Sight glass level was normal and was left in service to allow the sight glass to heat up to facilitate "hot torque" of the bolting. No level transient occurred at this time.
- At ~1100, the sight glass was isolated to allow "hot torque" and that activity was completed at about 1230.
- At ~ 1300, began restoring sight glass using OP 2320. When bottom sight glass isolation was opened, level went high off-scale in the sight glass. Waited to determine if sight glass indication would stabilize.
- Determined that sight glass ball check valves needed to be reseated.
- ~ 1419 reset ball check valves in accordance with OP2320. Sight glass level returned to normal and was stable (see Attachment 1).
- ~ 1422 operators left the area.
- ~ 1424 2A Heater low level alarms received.
- ~ 1425 Heater drain flow dropped to zero.
- ~ 1427 B SGFP trips
- ~ 1427 SM orders Reactor tripped on lowering SG level.
- ~ 1428 Heater drain flow returned to normal (see Attachment 2 for detailed time line).

Cause of Event

The event was initiated by restoration of the sight glass. There was no adverse action by the operators, the proper procedure was properly used for restoration. Appropriate guidance for resetting the ball check valves was sought, obtained and implemented. The transient initiated by restoration of the sight glass should be within the recovery capability of the control system.

Following the initiation of the transient (see Attachment 3), it appears that slow action of 2-HD-103, Heater 2A normal level control, exacerbated the severity of the transient, resulting in a large volume of relatively hot water entering the heater drain tank. Heater

drain tank pressure increased, stopping or reducing flow from the 3A/B feedwater heaters resulting in high level and automatic extraction steam valve isolation.

With extraction steam isolated to the 3A/B heaters, steam pressure in those heaters decayed to a low value (~30 psig) over a short time period. 2-HD-104, Heater Drain Tank Vent to 3A/B heaters, remained open from the initiation of the transient until the main turbine tripped following the reactor trip. 2-HD-104 should have closed upon receipt of either the 3A or 3B heater high level alarm. A wiring error precluded the closing of 2-HD-104. With the vent valve open, heater drain tank pressure decreased as a function of 3A/B heater pressure until saturation pressure for the contents of the heater drain tank was reached. At that point the heater drain tank flashed causing loss of NPSH to the heater drain pumps and subsequent total loss of heater drain flow. Shortly thereafter, feed pump suction pressure decreased, SG levels began to decrease, and one steam generator feed pump tripped. The SM directed the manual reactor trip. Operator response during and after the event was appropriate and exhibited conservative decision making. Plant system response was normal with minor exceptions. Each of the exceptions was dealt with using CRs specific to the exception.

Root Cause

The root cause of this event is a historical condition whereby the control wiring of 2-HD-104 does not allow the valve to function as required to mitigate the consequences of a loss or rapid reduction of extraction steam pressure on the heater drain tank.

Corrective Action

Pre-Startup

- Optimize performance of 2-HD-103C
- Correct Logic for 2-HD-104
- Establish controls to prevent sight glass restoration until evaluation of method has been completed and appropriate procedure changes have been made.

During Power Ascension

- Monitor and groom as necessary the heater level controls.
- Evaluate heater drain pumps for performance degradation.

Post Start-up

- Take action to minimize the challenge to the heater level control system both during and following restoration of a sight glass by performing one of the following:
    - Correct procedure method to de-sensitize the process to the extent possible.
    - Establish practice that once a sight glass is removed from service, it will not be restored until the plant is off-line.
    - Implement design changes as necessary to install the same type of level indication as is present on the bulk of the level control system to altogether eliminate sight glass restoration as a challenge to system operation.
- During the upcoming outage, "Rod out" the level sensing lines between the heaters and the level transmitters to ensure optimal control loop performance. This would

include all feedwater heaters.

Investigation to Determine Cause

Two separate areas for investigation were identified. One was the initiation and severity of the 2A feedwater heater oscillations. The other was the method by which heater drain flow was lost. The two areas are detailed separately below. In each area, a possible failure mechanism is identified, the item that was evaluated is stated, and the result of the evaluation is provided.

2A Heater Oscillations

Incorrect procedure used for valving in sight glass

Item: Valving sequence needs to be correct to minimize potential for transient.

Result: Operations personnel followed the procedure (OP 2320) for initial valving in of sight glass. There was no indication of inappropriate operator action. The procedure does not have instructions for resetting seated excess flow check valves although the method used by the operators was correct and appropriate (matching in all particulars the method previously espoused in OP 2320). If there were no consequences associated with this particular valving evolution, it would be considered a 'skill of the craft' type activity. Given the demonstrated impact, procedural guidance is appropriate.

Incorrect procedure method

Item: Valving in sight glasses has initiated transients in the past. Corrective action was to change sequence of opening valves. The displacers are sensitive to slight pressure and temperature changes in the sensing line.

Result: The procedure method was changed in the May, 1999 time frame. Previous versions of procedure were reviewed and it was noted that the changes have eliminated the use of the sight glass isolation valves (for those heaters having sight glasses) during the restoration process. This change tends to hamper the operators ability to restore the sight glass slowly and increases the probability of initiating a level transient by adverse reaction of the displacer regardless of the care with which the operator restores the sight glass.

Proper damping /throttling 2A Controller (5T open vs ¾ T for 2B)

Item: A known deficiency in the heater level control system results in the need to throttle the lower isolation to the displacers (level control output) for the system to minimize erratic system response.

Result: The heater had not needed grooming. The displacer throttle valve is set to engineering recommended position. The 2B heater has been unstable in the past requiring throttling it's sensing line to ¾ open to stabilize the level. It is worth noting that the Fisher-Rosemount controllers are designed to have small orifices installed to dampen oscillations. These orifices were removed during initial installation. This is the reason that we have had to resort to throttling the inlet isolations.

2-HD-103C, 2A Heater Normal Level Control, sticky

Item: During the May 25, 1999 trip, 2-HD-103C exhibited sticky operation that appeared to have initiated a divergent oscillation in heater 2A level which coupled with other conditions to result in a manual reactor trip. 2A heater level response was not damped in time to prevent loss of heater level

Result: Valve disassembly shows no internal problems. Stroking through controller shows what appears to be slow response (about 1 minute stroke time).

Loss of Heater Drain Flow

Bulk flashing Heater Drain Tank

Item: This potential needs to be evaluated to determine if a change in pressure in the heater drain tank was responsible for loss of heater drain flow as a result of cavitation or loss of NPSH on the heater drain pumps.

Results: The sequence of events will support bulk flashing of the heater drain tank at the time of loss of heater drain flow if the heater drain tank pressure is equivalent to 3A/B heater shell pressure.

2-HD-109, Heater Drain Tank Normal Level control, common failure (controller malfunction, stem/disk separation/ binding)

Item: Due to limited availability of archived data relative to discharge pressure of the heater drain pumps, it is possible that 2-HD-109 went closed in error or stuck closed and caused the loss of heater drains flow. Need to evaluate the possibility that the valve moved properly to a more closed position and then became stuck in that position until a mechanical transient occurred unsticking it

Results: Post trip operation of 2-HD-109 appears to have been normal. Stroke results from aircet testing indicate no abnormalities.

2-HD-110, Heater Drain Tank High Level control, opened early, stuck open

Item: Need to evaluate the possibility that this valve opened, diverting flow to the main condenser and starving the suction of the heater drain pumps, resulting in loss of NPSH and subsequent cavitation.

Results: Evaluation of heater level response following the loss of heater drain flow leads to a conclusion that it is unlikely that 2-HD-110 responded improperly. No further evaluation necessary.

2-HD-12, check valve downstream of 2-HD-109, valve disk separation

Item: Check valve disk separation occurred resulting in flow blockage.

Results: Evaluation of heater drain flow post trip, leads to conclusion that check valve failure is unlikely. No further evaluation required.

2-HD-104, Heater Drain Tank to 3A/B FW Heater Vent, failure to close following 3A/B Level High

Item: System description and alarm response procedure for the 3A/B heater level high shows that 2-HD-104 should close on receipt of either 3A or 3B heater level high.

Results: Logic diagram shows that 2-HD-104 will close only if three conditions are present; 3A Level High AND 3B Level High AND High Rate of Change on main turbine first stage pressure. Physical testing in the field shows that the logic diagram correctly models as built and that 2-HD-104 will NOT close on a single input signal. The as built operation of 2-HD-104 supports depressurization of the heater drain tank as a function of 3A/B heater pressure.

2-HD-109 manual loading stations bumped

Item: Work in the area could have resulted in mispositioning of controllers

Result: No known work in the immediate vicinity. Controller in correct position. No further evaluation necessary.

Previous Events

The heater level transient from May 1999, CR M2-99-1730, was evaluated to determine if corrective actions had been properly implemented and if the transient observed in this current occurrence could or should have been detected in the previous transient. The evaluation determined that this event could not have been detected or anticipated by any of the events in the May 1999 event. The recommended corrective action from CR M2-99-1730, modifying system design to improve stability and responsiveness, is still strongly recommended for implementation at the earliest opportunity.

Additionally, two specific PIRs were evaluated, 94-076 and 94-083. Both of these PIRs indicate level transients occurred, although to a lesser extent than the current event. 94-076 actually resulted in cavitation of the heater drain pumps (amps oscillating 50-100) following isolation of extraction to the 3A and 3B feedwater heaters. In this event the operators were able to recover and stabilize the 2B heater level without a plant trip.

Analysis of Transient Data (see Attachment 3 and 4)

The transient appears to have been initiated by the restoration of the sight glass on the 2A feedwater heater. Empirical data from past operations of this type have shown the potential for sight glass restoration to initiate a feedwater heater level transient. Also, the time relationship between valving in the sight glass and the transient initiation match closely. The operators used the proper procedure in the proper manner. One item of note is that the method of sight glass restoration is now different than it was prior to May 15, 1999. The 2A sight glass has been restored successfully this cycle using the current process. Based on calculation performed by the SAB representative, the restoration activity can be shown to have the ability to initiate a heater level transient. The transient appears to have been exacerbated by what appears to be a relatively slow response of 2-HD-103C, normal level control, resulting in complete or nearly complete loss of level in the 2A heater (as evidenced by an increase in heater drain tank level and heater drain cooler outlet temperature approaching saturation temperature for shell pressure in the 2A heater). The loss of level in the 2A heater allowed pressurization of the heater drain tank via direct introduction steam drains from the drain cooler section of the feedwater heater. The pressurization of the heater drain tank resulted in seating the 3A/B outlet check valves with a concomitant level rise in those heaters. At high level, the extraction steam was isolated to the 3A/B heaters. During this time, the 2B feedwater heater continued to function normally, no level alarms were received as a result of untoward operation of the 2B heater level control system.

Evaluation of the relationship between the 3A/B Feedwater shell pressure and the temperature in the heater drain tank revealed the potential for the heater drain tank to have undergone bulk flashing. A necessary attribute to allow this phenomena to occur was for the heater drain tank to have physical communication with the 3A/B heater shell side following isolation of the extraction steam. There are two paths that would allow this communication, the outlet check valves, 2-HD-6A/B (fail to seal, back-leakage) and 2-HD-104, Heater Drain tank vent to the 3A/B heaters. If the communication existed, the profile for 3A/B heater drain tank pressure decay matches with the hypothesized bulk flashing of the heater drain tank with subsequent loss of heater drain flow.

A test of 2-HD-104 function was requested and conducted. Based upon what appears to be an original Bechtel write-up, the test was requested to determine whether or not 2-HD-104 would close on receipt on any one of three signals; High Level in 3A heater, High Level in 3B Heater, OR High rate of decrease in turbine first stage pressure. When the test was performed, it was determined that the circuit is set up as an AND function, that is, all three signals must exist to cause the valve to close. With this information, the ERT has determined that the hypothesis was correct, that the heater drain tank depressurized to 3A/B heater pressure through 2-HD-104 and caused the loss of heater drain flow due to bulk flashing in the heater drain tank with the resultant loss of suction to the heater drain pumps.

When the turbine tripped, 2-HD-104 closed and the heater drain tank rapidly re-pressurized, restoring heater drain flow.

Cause of Event

The event was initiated by restoration of the sight glass. There was no adverse action by the operators, the proper procedure was properly used for restoration. Appropriate guidance for resetting the ball check valves was sought, obtained and implemented. The transient initiated by restoration of the sight glass should be within the recovery capability of the control system.

Following the initiation of the transient, it appears that slow action of 2-HD-103, Heater 2A normal level control, exacerbated the severity of the transient resulting in a large volume of relatively hot water entering the heater drain tank. Heater drain tank pressure increased, stopping or reducing flow from the 3A/B feedwater heaters resulting in high level and automatic extraction steam valve isolation.

With extraction steam isolated to the 3A/B heaters, steam pressure in those heaters decayed to a low value (~30 psig) over a short time period. 2-HD-104, Heater Drain Tank Vent to 3A/B heaters, remained open from the initiation of the transient until the main turbine tripped following the reactor trip. 2-HD-104 should have closed upon receipt of either the 3A or 3B heater high level alarm. A wiring error precluded the closing of 2-HD-104. With the vent valve open, heater drain tank pressure decreased as a function of 3A/B heater pressure until saturation pressure for the contents of the heater drain tank was reached. At that point the heater drain tank flashed causing loss of NPSH to the heater drain pumps and subsequent total loss of heater drain flow. Shortly thereafter, feed pump suction pressure decreased, SG levels began to decrease, and one steam generator feed pump tripped. The SM directed the manual reactor trip. Operator response during and after the event was appropriate and exhibited conservative decision making. Plant system response was normal with minor exceptions. Each of the exceptions was dealt with using CRs specific to the exception.

Root Cause

The root cause of this event is n historical event whereby the control wiring of 2-HD-104 does not allow the valve to function as required to mitigate the consequences of a loss or rapid reduction of extraction steam pressure on the heater drain tank.

Interim Recommendation

At approximately 1500 on 1/28/99, the ERT presented to PORC that there were no circumstances in evidence related to the heater drain level transient that would preclude reactor startup. Additional time was required to complete evaluation for turbine startup.

Corrective Action Recommendations (Prior to Startup)

Item: Optimize performance of 2-HD-103C. This should include, to the extent possible, improvement in stroke time, evaluation and correction of any control loop deficiencies (not requiring design change), and reasonableness evaluation that performance is satisfactory.

Result: Both 2HD-103C and 2-HD-103D have been evaluated. Stroke times for the two valves are now similar and performance has been optimized. At about 75% power, the heater drain system appeared to be very stable with very similar control signals and levels. See AWO (2A) M2-00-01693, (2B) M2-00-01985

Item: Correct logic action for 2-HD-104. This should include evaluation of effect on operation of a change such that the valve will close on any single input. either heater level high or high rate of change of turbine first stage pressure.

Result: The logic for 2-HD-104 has been corrected such that it will close upon receipt of any of three signals; 3A high level OR 3A high level OR High rate of change of turbine first stage pressure. A change to the alarm response procedure for high 3A or 3B level was required as a result of this logic change. See DCN DM2-00-0070-00 and ARP 2590D, AA-19 and AB-19.

Item: OPS to establish guidance to preclude sight glass restoration without proper guidance. OPS to be made aware that current guidance in procedure is not sufficiently sensitive to potential for level transient in feedwater heaters.

Result: OPS Manager issued night order 1-29-00-1.

Compensatory Recommendations (During Startup)

Item: I&C personnel on standby to monitor and groom feedwater heater level controls during power escalation.

Result: 2A heater did require grooming on the way up. (IC 2426C, Attachment)

Item: Monitor heater drain pump performance to determine if any degradation occurred during the period of no flow.

Result: Preliminary indication is that no detectable degradation occurred.

Corrective Actions (Post Startup)

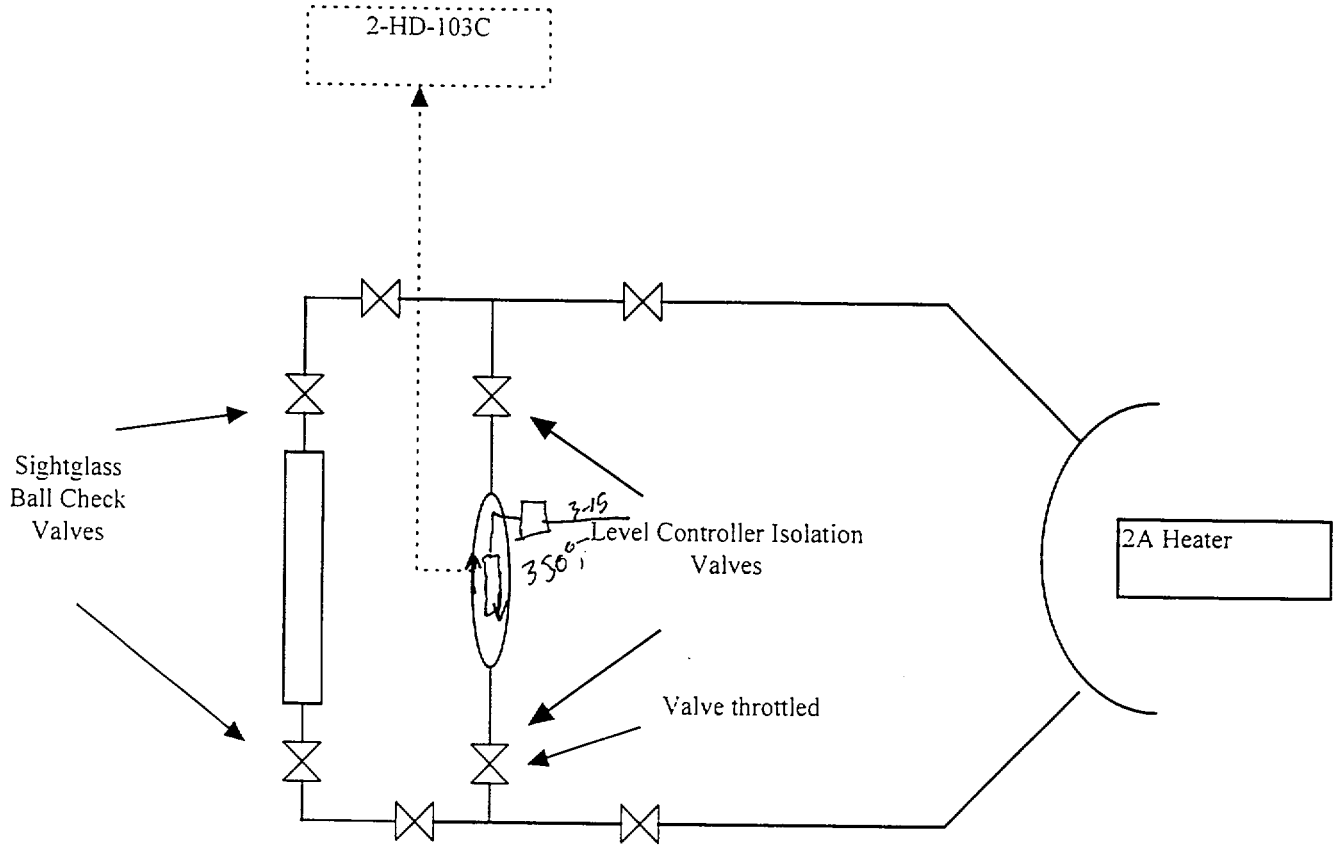
- Evaluate changes to ARP 2590, AA-19 and AB-19 to confirm that no additional changes are required to either the heater drain system procedure or to the other alarm response procedures.

- Take action to minimize the challenge to the heater level control system both during and following restoration of a sight glass by performing one of the following:

    - Correct procedure method to de-sensitize the process to the extent possible.
    - Establish practice that once a sight glass is remove from service, it will not be restored until the plant is off-line.
    - Implement design changes as necessary to install the same type of level indication as is present on the bulk of the level control system to altogether eliminate sight glass restoration as a challenge to system operation.

- During the upcoming outage, "Rod out" the level sensing lines between the heaters and the level transmitters to ensure optimal control loop performance. This would include all feedwater heaters.

Attachment 1
Heater Sight Glass / Level Sensor



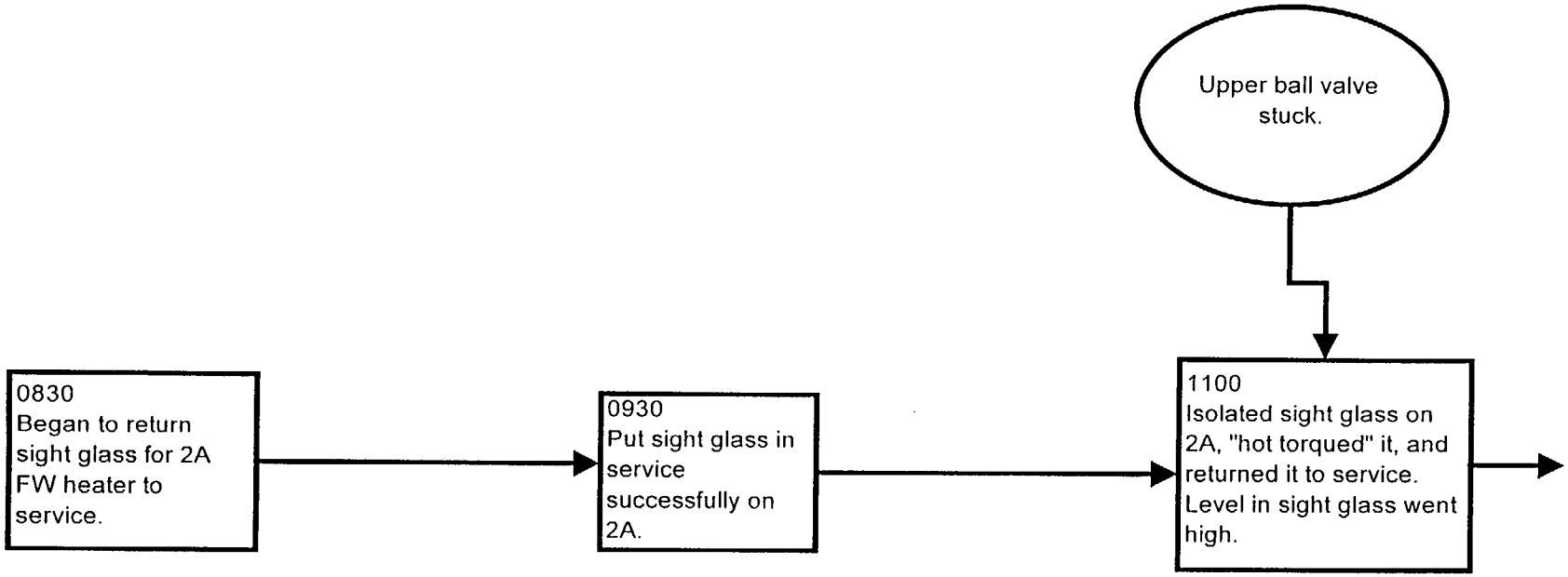
P + I

OUTPUT = K (ACT LVL − STPT) + ∫ error dt

9#

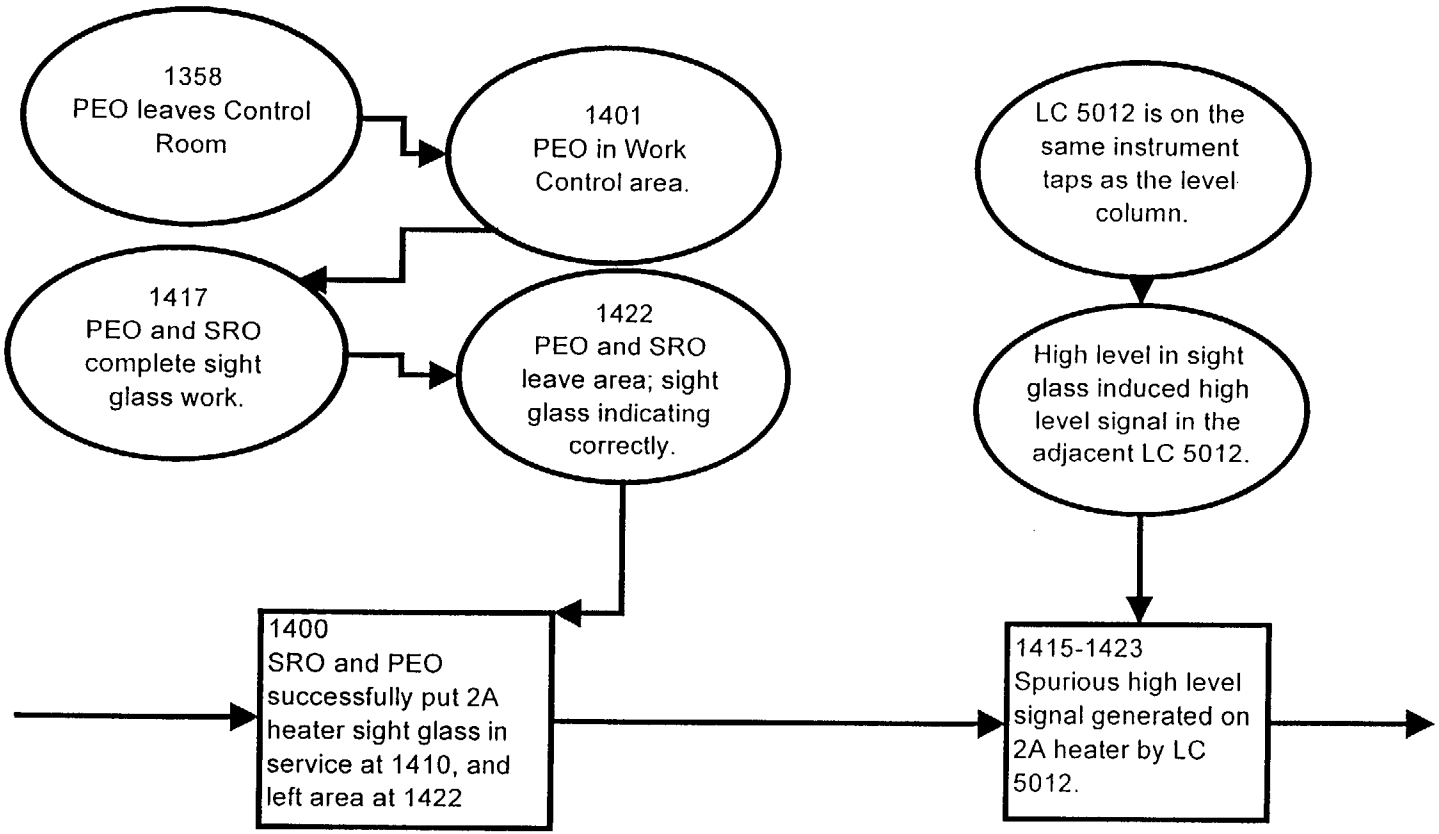
Attachment 2

Event and Causal Factor Chart - Unit 2 Level Manual Reactor Trip, January 27, 2000



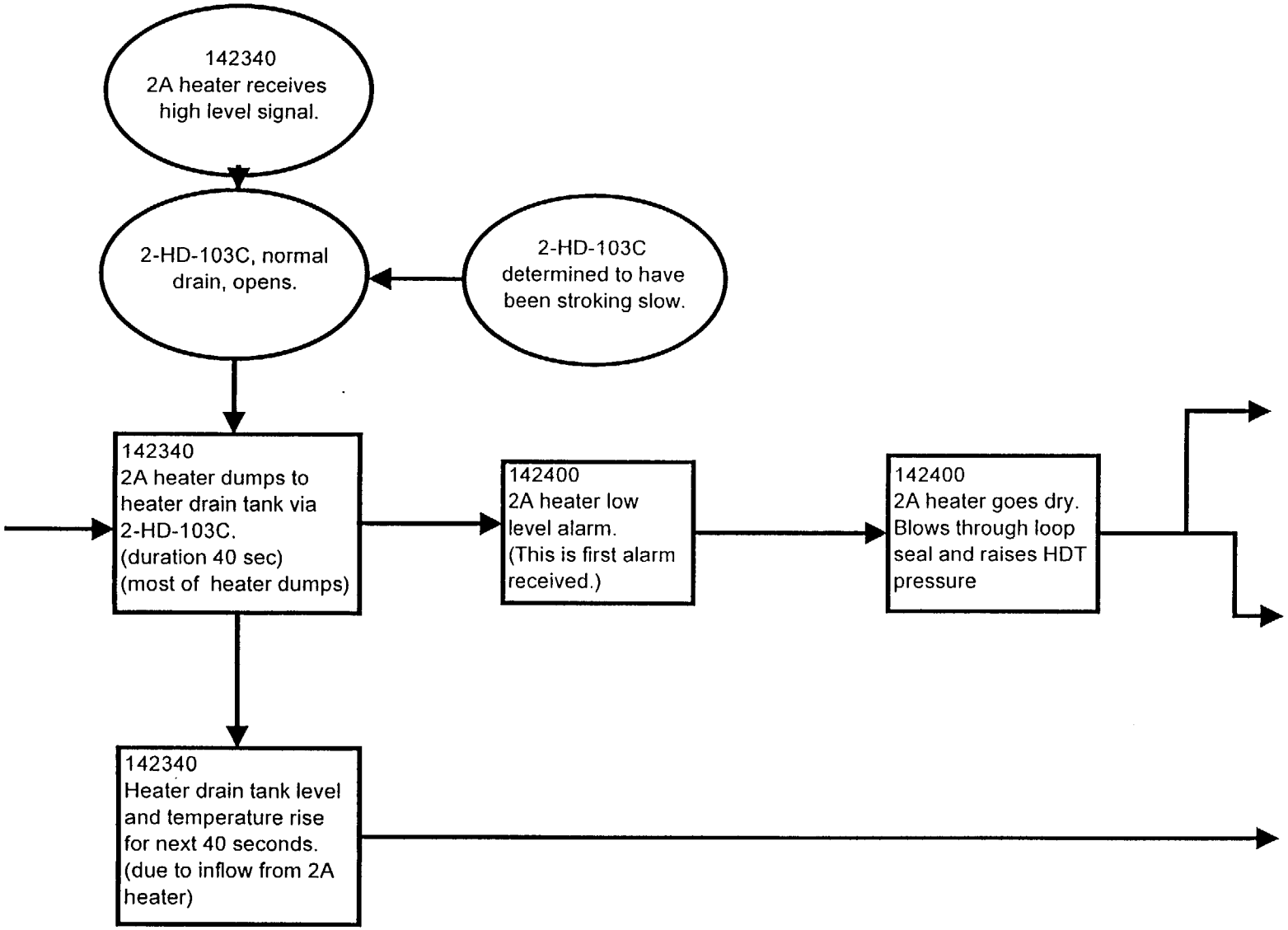
Attachment 2

Event and Causal Factor Chart - Unit 2 Level Manual Reactor Trip, January 27, 2000



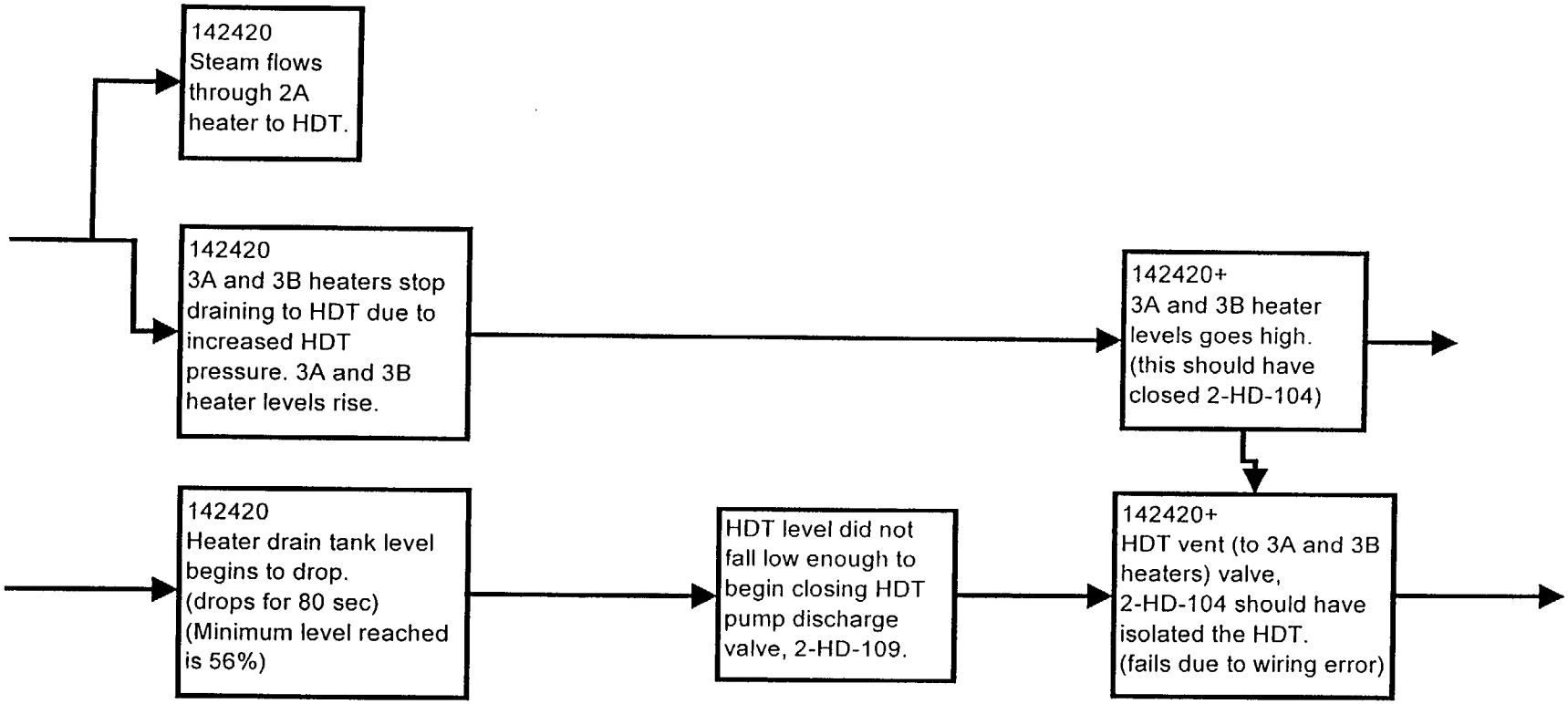
Attachment 2

Event and Causal Factor Chart - Unit 2 Level Manual Reactor Trip, January 27, 2000



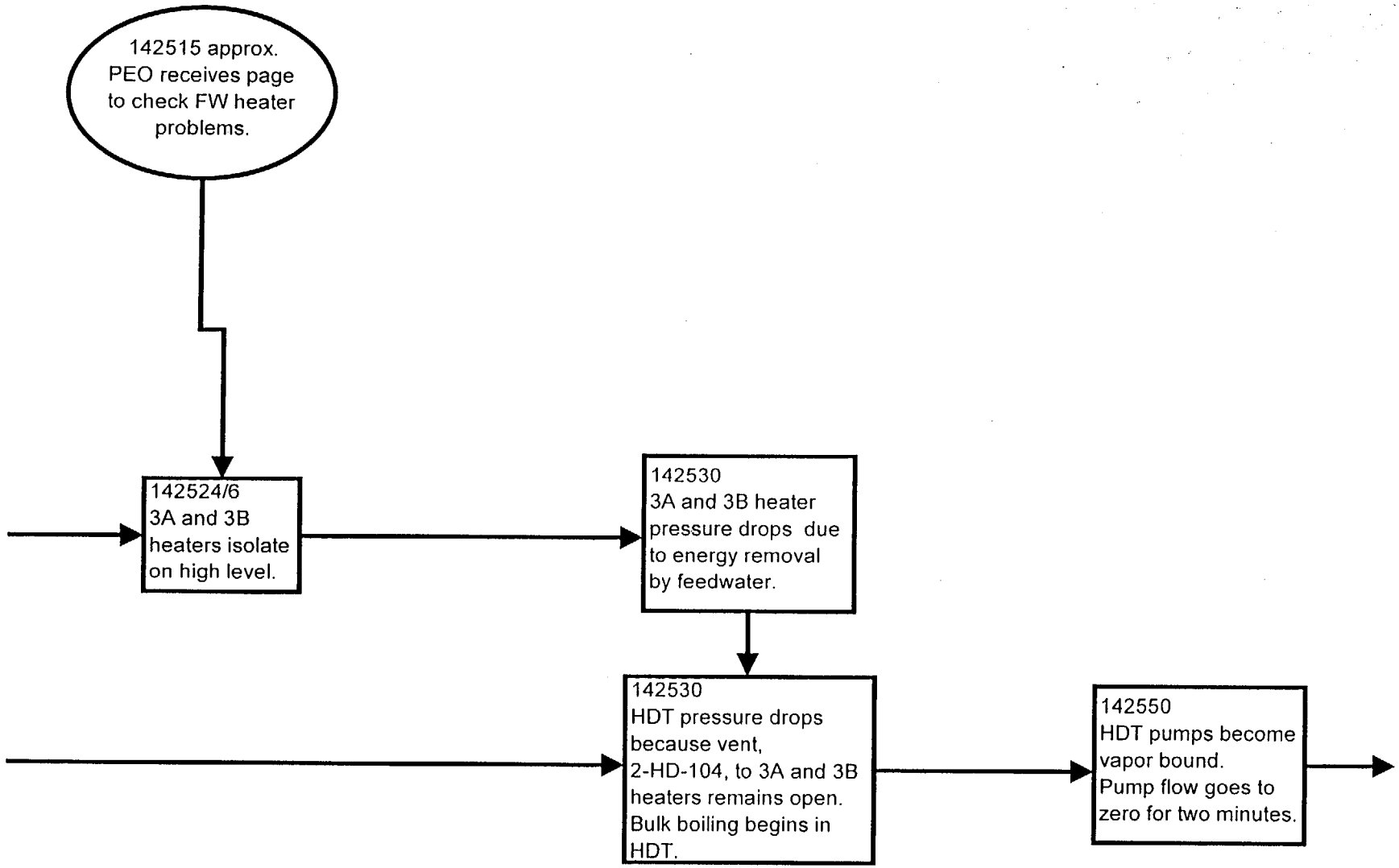
Attachment 2

Event and Causal Factor Chart - Unit 2 Level Manual Reactor Trip, January 27, 2000



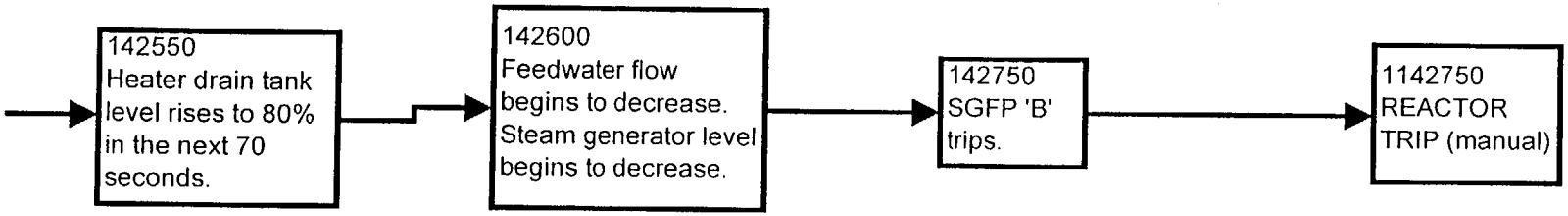
Attachment 2

Event and Causal Factor Chart - Unit 2 Level Manual Reactor Trip, January 27, 2000

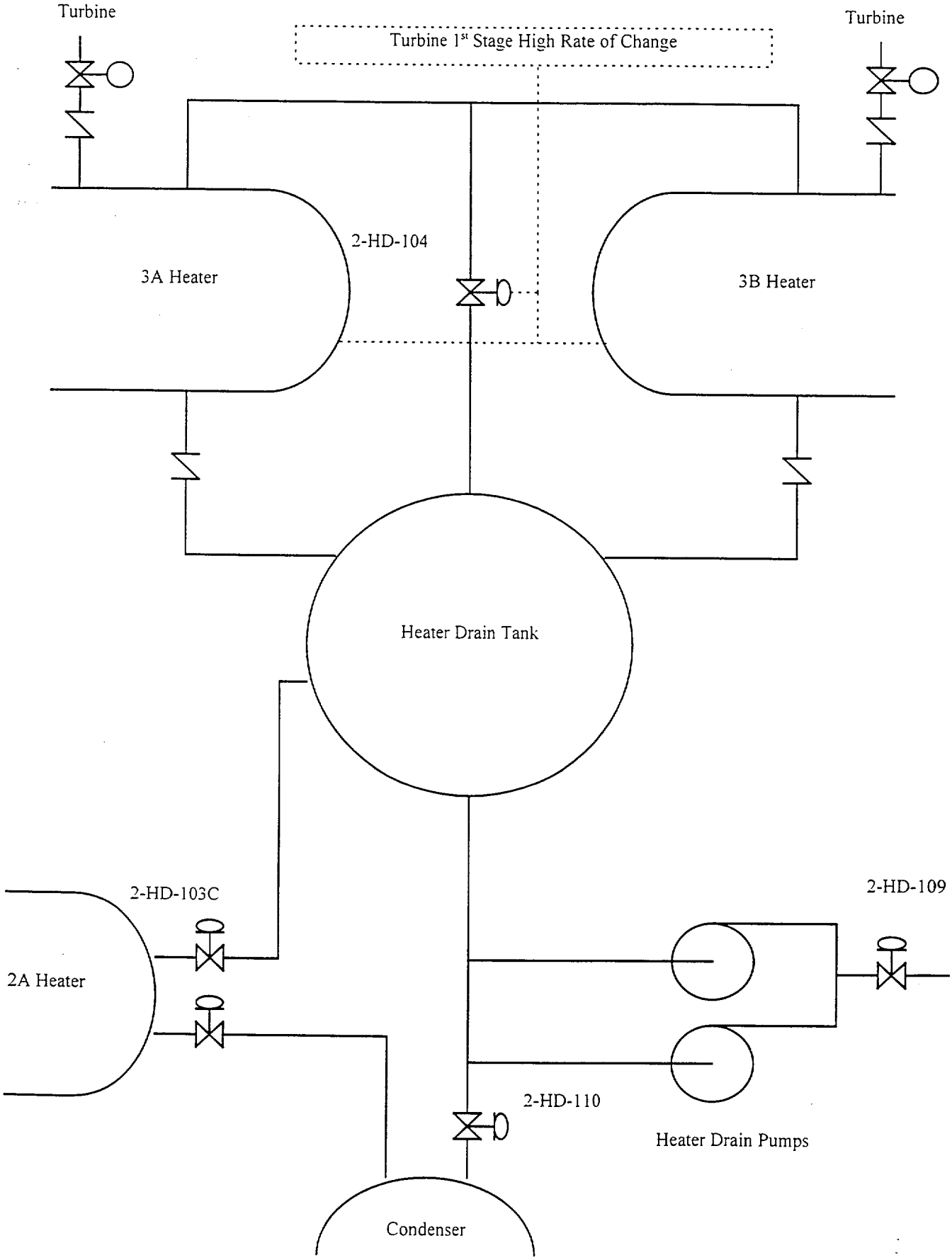


Attachment 2

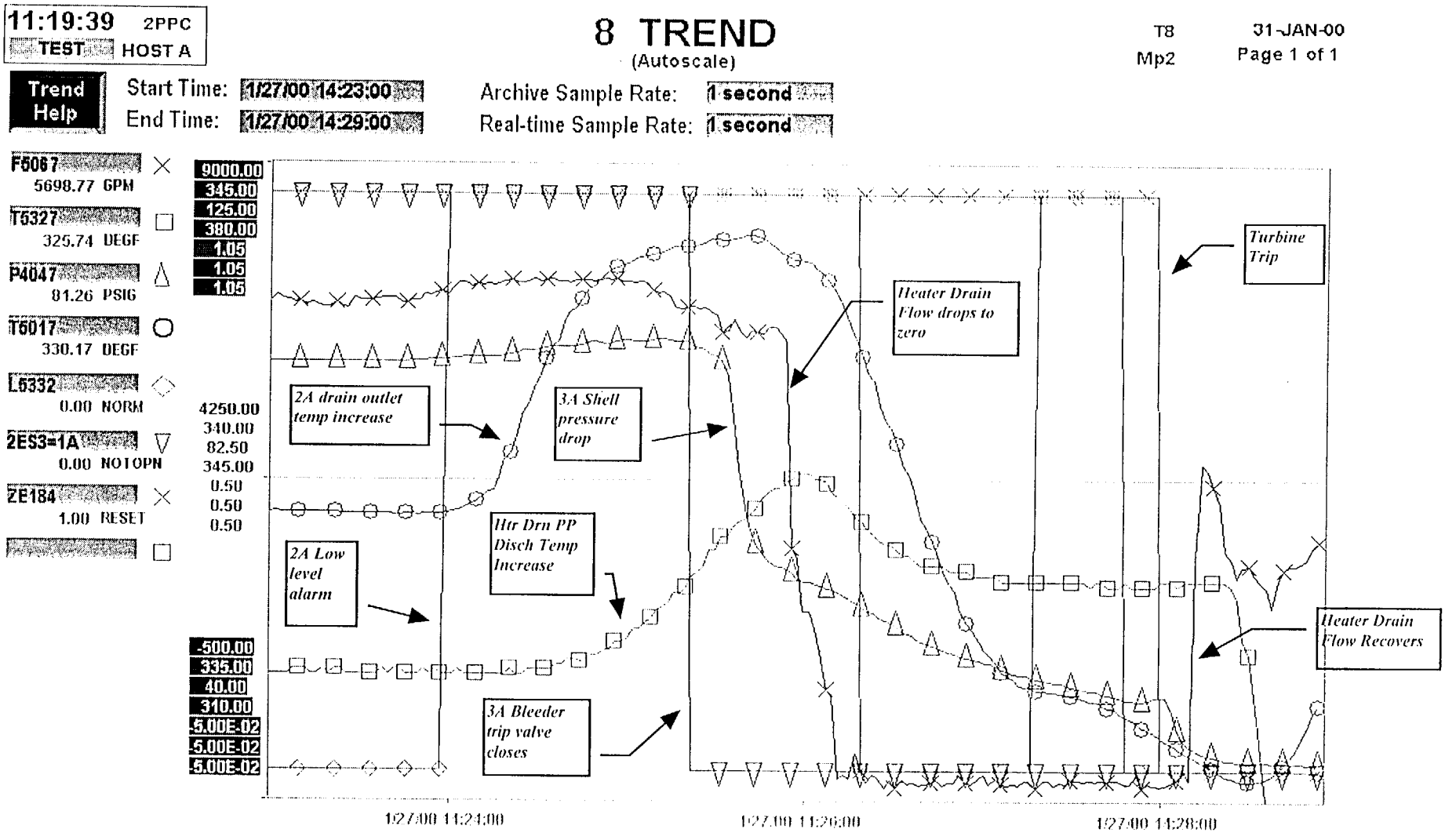
Event and Causal Factor Chart - Unit 2 Level Manual Reactor Trip, January 27, 2000



Attachment 3
Heater Drain System Basic Sketch



Attachment 4
Trend Date - Unit 2 Level Manual Reactor Trip, January 27, 2000



Unit 2 SG Level Manual Reactor Trip January 27, 2000

On January 27, 2000 at 1427, a manual reactor trip was trip was initiated due to a drop in Steam Generator feed level to approximately 57% and the trip of a SGFP. This loss of feed level occurred after feedwater heater oscillations and flow was lost to the heater drain pumps. Event initiation is unclear. No human performance issues appear to be involved. Heater drain tank normal level control valve 2-HD-109 and 2A heater normal level control valve 2-HD-103C experienced anomalous responses. Valve 2-HD-103C was considered to operate with "sticky" response and initiated the May 25, 1999 feedwater transient which led to the reactor trip. Further investigation of the controls and physical condition of these valves are being investigated.

The plant responded normally with minor exception. All safety related equipment performed as expected and the plant was stabilized at normal post trip parameters. All procedurally required actions were accomplished.

Sequence of Events on January 27

- Approximately 0830 the 2A Feedwater Heater sight glass was returned to service after leak repair. The sight glass indicated off scale.
- Determined that sight glass ball check valves needed to be reseated.
- Approximately 1400 reset ball check valves in accordance with OP2320. Sight glass level returned to normal and was stable.
- Approximately 1424 2A Heater level alarms received.
- Approximately 1425 Heater drain flow dropped to zero.
- Approximately 1427 B SGFP trips
- Approximately 1427 SM orders Reactor tripped on lowering SG level.

Action Plan

1. Perform troubleshooting/calibration of heater drain tank normal level control valve 2-HD-109 and 2A heater normal level control valve 2-HD-103C.

2. Open and inspect these valves if nothing is found in the control loop.

ITEM # _____

Unit 2 SG Level Manual Reactor Trip January 27, 2000

On January 27, 2000 at 1427, a manual reactor trip was initiated due to a drop in Steam Generator feed level to approximately 57% and the trip of a SGFP. This loss of feed level occurred after feedwater heater oscillations and loss of all heater drain pump flow.

The plant responded normally with minor exception. All safety related equipment performed as expected and the plant was stabilized at normal post trip parameters. All procedurally required actions were accomplished.

Sequence of Events on January 27

- Approximately 0830 the 2A Feedwater Heater sight glass was returned to service after leak repair. The sight glass indicated off scale. High
- Determined that sight glass ball check valves needed to be reseated.
- Approximately 1419 reset ball check valves in accordance with OP2320. Sight glass level returned to normal and was stable.
- Approximately 1422 operators left the area.
- Approximately 1424 2A Heater ~~high~~ low level alarms received.
- Approximately 1425 Heater drain flow dropped to zero.
- Approximately 1427 B SGFP trips
- Approximately 1427 SM orders Reactor tripped on lowering SG level.
- Approximately 1428 Heater drain flow returned to normal.

Action Plan

1. Perform troubleshooting/calibration of heater drain tank normal level control valve 2-HD-109 and 2A heater normal level control valve 2-HD-103C.

2. Open and inspect these valves if nothing is found in the control loop.

3. Detailed review of sightglass alignment method.

4. Review heater drain system pressure and temperatures for flashing.

Potential Causes

1. 2A Heater Oscillations

- incorrect valving in sight glass (not following proc)
  - Interview of personnel involved and walkdown of area identified no issues
- incorrect procedure method
  - Valving in sightglasses has initiated transient in the past. Corrective action was to change sequence of opening valves. The displacers are sensitive to slight pressure and temperature changes in the sensing line.
- proper damping /throttling 2A Controller (5T open vs $\frac{3}{4}$ T for 2B)
  - The heater had not needed grooming. The displacer throttle valve is set to engineering recommended position. The 2B heater has been unstable in the past requiring throttling it's sensing line to $\frac{3}{4}$ open to stabilize the level.
- 2-HD-103C sticky
  - AWO to troubleshoot and inspect
- valve/controllers bumped, etc...
  - No indication of work in area.

2. Loss of Htr Drain Flow

- HD-109 controller malfunction
  - AWO checked positioner sat.
- HD-109 stem/disk sep/ binding
  - AWO stroked smooth
- Bulk flashing Htr Drain Tank
  - pressure and temperature changes challange htr drn pump NPSH
- HD-110 opened early, stuck open
  - Condenser pressures do not indicate 110 opened before loss of heater drain flow.
- HD-12 (downstream HD-109) check valve disk separation
  - Heater drain flow returned to normal post trip, unlikely.
- HD-104 (3A/B vent to htr drn tk) failure to close on high 3 heater level)
- HD-109 manual loading stations bumped

Summary

The primary plant responded as expected from the manual reactor trip. The cause of the secondary side transient appears to be the 2A heater level controller initiating an oscillation resulting from sensing line pressure and or temperature changes after the sightglass was returned to service. This has been an initiator in the past. The resulting severe secondary side response appears to be a result of loss of NPSH to the heater drain pumps causing cavitation of the pumps. Without any heater drain flow, the steam generator feed flow could not be maintained at 100 %. The reason the transient was severe enough to cause the loss of NPSH is still under investigation.

The operator response to the event was appropriate prior to and after the manual reactor trip.

Since the transient is only associated with secondary systems and response, the investigation can continue without any holds on reactor plant startup.

15:12:25 Mp2 Host B | 15:12:26 Mp3 Host A

4 / 4 TREND

(Autoscale)

Test MP2: 27-JAN-00
MP - LAN MP3: 27-JAN-00

Trend Help

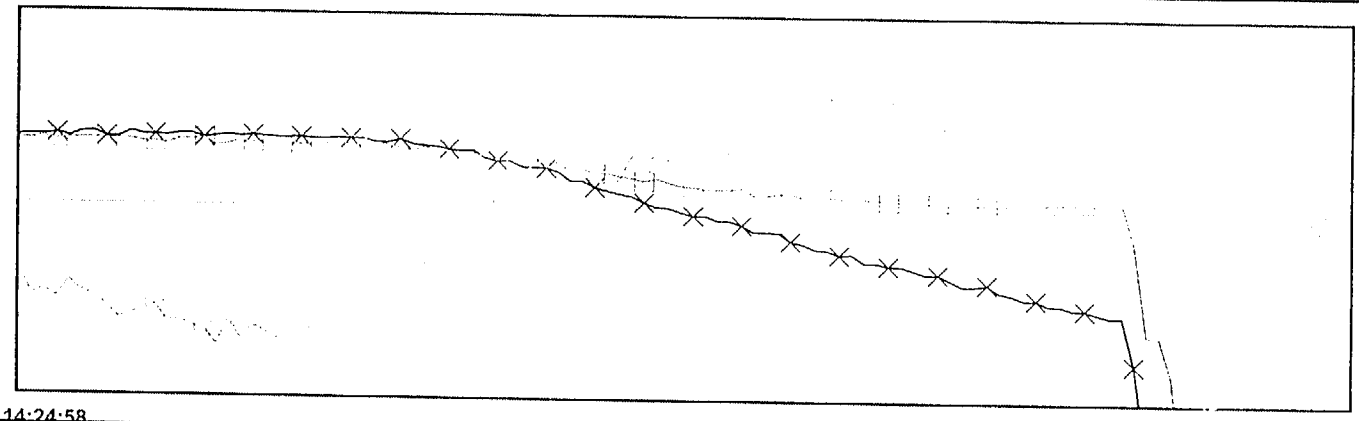
Start Time: [redacted]
End Time: [redacted]

Archive Sample Rate: [redacted]
Real-time Sample Rate: [redacted]

[redacted] 60.07 %
SG2LVL 64.34 %
F5067 R-201.23 GPM
L5064 X102.98 PRCT

80.00 / 80.00 / 0.00
65.00 / 65.00 / 70.00
50.00 / 50.00 / 50.00

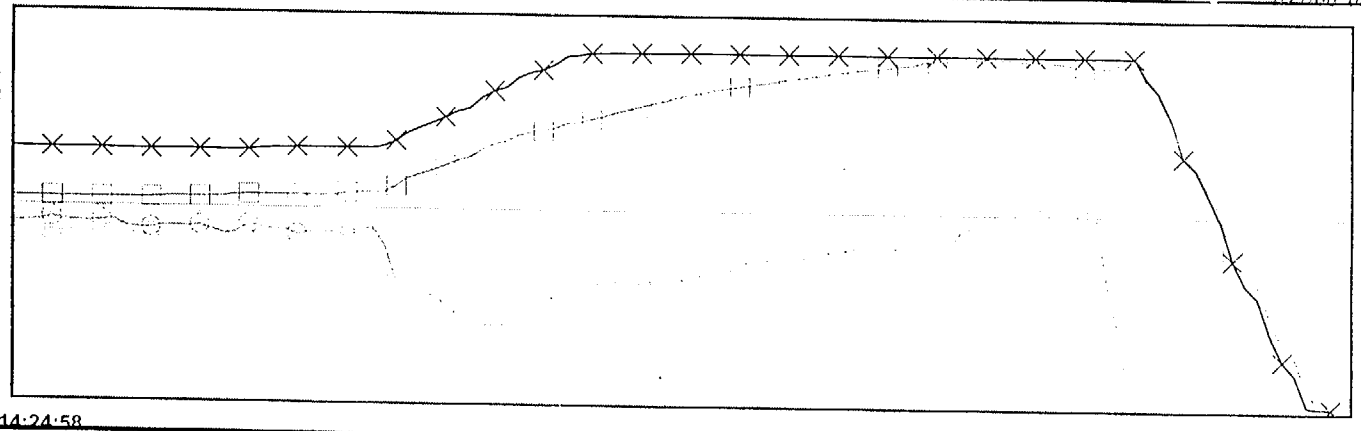
1/27/00 14:24:58 — 1/27/00 14:28:35



[redacted] 0.58 PRCT
Z5269 0.14 PRCT
CVFEED1 0.39 K#/H
CVFEED2 0.00 K#/H

110.00 / 110.00 / 7000.00
55.00 / 55.00 / 6000.00
0.00 / 0.00 / 5000.00

1/27/00 14:24:58 — 1/27/00 14:28:35



Htr Drn Pump Disch Flow

Htr Drn Tank Level

3

14:55:41 14:55:42
Mp2 Host B Mp3 Host A

4 / 4 TREND

(Auto-scale)

MP2: 27-JAN-00
MP3: 27-JAN-00

Trend Help

Start Time: [illegible]
End Time: [illegible]

Archive Sample Rate: 2 seconds
Real-time Sample Rate: 1 second

[illegible] 34.99 %
80.00
80.00

SG2LVL 41.35 %
50.00
50.00

RXPWR 4.17E-06 %
20.00
20.00

1/27/00 14:24:58 1/27/00 14:28:35

[illegible] 0.61 PRCT
110.00
100.00

Z5269 0.17 PRCT
55.00
50.00

0.00
0.00

1/27/00 14:24:58 1/27/00 14:28:35

15:07:57 15:08:00
Mp2 Host B Mp3 Host A

4 / 4 TREND
(Autoscale)

T44 MP2: 27-JAN-00
MP - LAN MP3: 27-JAN-00

Trend Help

Start Time: [redacted]
End Time: [redacted]

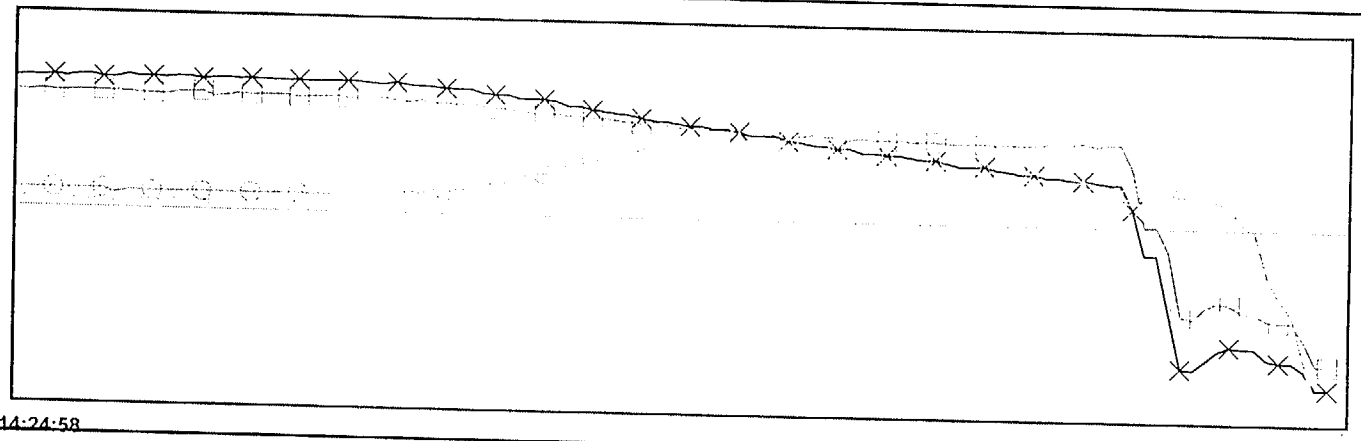
Archive Sample Rate: [redacted]
Real-time Sample Rate: [redacted]

[redacted] ✕
58.28
%
80.00
80.00
[redacted]
[redacted]

SG2LVL □
62.09
%
50.00
55.00
[redacted]

T5317 Δ
410.17
DEGF
433.50

T5318 ○
411.05
DEGF
20.00
30.00
[redacted]
427.00



1/27/00 14:24:58

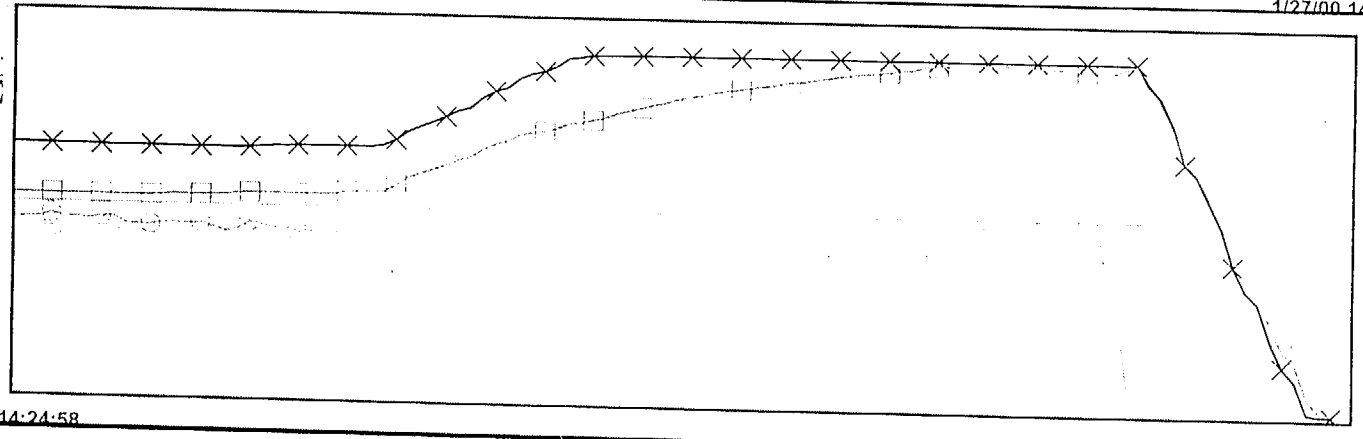
1/27/00 14:28:35

[redacted] ✕
0.59
PRCT
110.00
110.00
[redacted]
7000.00

Z5269 □
0.16
PRCT
55.00
55.00
[redacted]

CVFEED1 Δ
0.39
K#/H
6000.00

CVFEED2 ○
0.00
K#/H
0.00
0.00
[redacted]
5000.00



1/27/00 14:24:58

1/27/00 14:28:35

Daily Events Report

U.S. Nuclear Regulatory Commission
Operations Center

Event Reports For
01/27/2000 - 01/28/2000

** EVENT NUMBERS **

36552 36607 36621 36629 36630 36631 36632 36633 36634 36635 36636 36637 36638

Fuel Cycle Facility

Event Number: 36552

FACILITY:	PADUCAH GASEOUS DIFFUSION PLANT
RXTYPE:	URANIUM ENRICHMENT FACILITY
COMMENTS:	2 DEMOCRACY CENTER 6903 ROCKLEDGE DRIVE BETHESDA, MD 20817 (301)564-3200
CITY:	PADUCAH
REGION:	3
COUNTY:	McCRACKEN
STATE:	KY
LICENSE#:	GDP-1
AGREEMENT:	Y
DOCKET:	0707001

NOTIFICATION DATE:	12/30/1999
NOTIFICATION TIME:	21:45[EST]
EVENT DATE:	12/30/1999
EVENT TIME:	11:30[CST]
LAST UPDATE DATE:	01/27/2000

PERSON	ORGANIZATION
BRUCE BURGESS	R3
JOHN HICKEY	NMSS

NRC NOTIFIED BY: ERIC WALKER
HQ OPS OFFICER: DICK JOLLIFFE

EMERGENCY CLASS: N/A
10 CFR SECTION:
OCBA 76.120(c)(2)(i) ACCID MT EQUIP FAILS

EVENT TEXT

NOTE: THIS EVENT IS A CONTINUATION OF EVENT #35790. (Refer the event #36018 and event #36605 for similar events at Portsmouth.)

At 1130 CST on 12/30/99, the Plant Shift Superintendent (PSS) was notified that during walkdowns of the High Pressure Fire Water System in C-337, a total of 13 corroded sprinkler heads were discovered in System B-2. The system was declared inoperable and actions were taken as required by the technical safety requirement. The PSS determined that an update to this event report is required.

The NRC Resident Inspector has been notified of this event.

* * * UPDATE 2233EST ON 1/12/00 FROM ERIC WALKER TO S. SANDIN * * *

At 0910 on 1/12/00 the Plant Shift Superintendent (PSS) was notified that during walk downs of the High Pressure Fire Water (HPFW) systems in C-337, two adjacent corroded heads were discovered on system B-10. Per Engineering Notice C-822-99-047 Rev. 2, the criteria necessary for system operability was not being met. The system was declared Inoperable and actions were taken as required by the TSR. The PSS determined that an update to this event report is required.

It has been determined that this event is reportable under 10CFR76.120(c)(2)

A/6

as an event in which equipment is disabled or fails to function as designed.

The NRC Resident Inspector has been notified of this event. Notified R3DO(Clayton) and NMSS(Haughney).

*** UPDATE ON 1/21/00 @ 2306 BY UNDERWOOD TO GOULD ***

At 1100 on 1/21/00, the Plant Shift Superintendent (PSS) was notified that during walk downs of the High Pressure Fire Water (HPFW) systems in C-337, thirteen corroded heads were discovered on system D-3. This system was previously inspected on 6/24/99. Also, at 1640 on 1/21/00, the PSS was notified that during walk downs of the HPFW systems in C-331, three adjacent corroded heads were discovered on system 12. This system was previously inspected by Fire Services Personnel on 4/10/99. Per Engineering Notice C-822-99-047 Rev. 2, the criteria necessary for system operability was not being met. The systems were declared inoperable and actions were taken as required by the TSR. The PSS determined that an update to this event report is required.

The NRC Resident Inspector has been notified of this event.

Reg 3 RDO(Hills) was notified.

* * * UPDATE 1549 1/27/2000 FROM WHITE TAKEN BY STRANSKY * * *

"At 1500 on 1/26/00, the Plant Shift Superintendent (PSS) was notified that during walk downs of the High Pressure Fire Water (HPFW) systems in C-337, eight corroded heads were discovered on system D-12. This system was previously inspected on 8/28/99. Per Engineering Notice C-822-99-047 Rev. 2, the criteria necessary for system operability was not being met. The systems were declared inoperable and actions were taken as required by the TSR. The PSS determined that an update to this event report is required."

The NRC resident inspector has been notified of this event.

Notified R3DO (Phillips).

!!!!!!!! THIS EVENT HAS BEEN RETRACTED. THIS EVENT HAS BEEN RETRACTED !!!!!!!

Power Reactor — Event Number: 36607

FACILITY: ZION	REGION: 3	NOTIFICATION DATE: 01/18/2000
UNIT: [1] [2] []	STATE: IL	NOTIFICATION TIME: 19:15[EST]
RXTYPE: [1] W-4-LP,[2] W-4-LP		EVENT DATE: 01/18/2000
		EVENT TIME: 18:02[CST]
NRC NOTIFIED BY: R. T. THORTON		LAST UPDATE DATE: 01/27/2000
HQ OPS OFFICER: LEIGH TROCINE		

		PERSON	ORGANIZATION
EMERGENCY CLASS:	N/A	DAVID HILLS	R3
10 CFR SECTION:		ROBERTA WARREN	IAT
DDDD 73.71	UNSPECIFIED PARAGRAPH	JIM CREED	IAT
		JIM BELANGER	IAT
		DICK ROSANO	IAT
		STEVE REYNOLDS	R3

UNIT	SCRAM CODE	RX CRIT	INIT PWR	INIT RX MODE	CURR PWR	CURR RX MODE
1	N	N	0	Decommissioned	0	Decommissioned
2	N	N	0	Decommissioned	0	Decommissioned

EVENT TEXT

SECURITY REPORT

UNSUBSTANTIATED BOMB THREAT. COMPENSATORY MEASURES TAKEN. LICENSEE INFORMED THE LOCAL POLICE DEPARTMENT.

* * * RETRACTION 1533 1/27/2000 FROM NOLDEN TAKEN BY STRANSKY * * *

After review of NRC Regulatory Guide 5.62, the licensee has determined that this event was not reportable. Notified R3DO (Phillips).

!!!!!!!! THIS EVENT HAS BEEN RETRACTED. THIS EVENT HAS BEEN RETRACTED !!!!!!!

Power Reactor — Event Number: 36621

FACILITY: INDIAN POINT — REGION: 1
UNIT: [2] [] []
RXTYPE: [2] W-4-LP,[3] W-4-LP — STATE: NY

NOTIFICATION DATE: 01/25/2000
NOTIFICATION TIME: 06:44[EST]
EVENT DATE: 01/25/2000
EVENT TIME: 06:10[EST]
LAST UPDATE DATE: 01/27/2000

NRC NOTIFIED BY: CORNAX
HQ OPS OFFICER: JOHN MacKINNON

PERSON	ORGANIZATION
JOHN ROGGE	R1

EMERGENCY CLASS: N/A
10 CFR SECTION:
AUNA 50.72(b)(1)(ii)(A) UNANALYZED COND OP

UNIT	SCRAM CODE	RX CRIT	INIT PWR	INIT RX MODE	CURR PWR	CURR RX MODE
2	N	Y	99	Power Operation	99	Power Operation

EVENT TEXT

BROKEN WINDOW IN A HIGH ENERGY LINE BREAK DOOR PLACES THE PLANT IN AN UNANALYZED CONDITION

A broken window in a High Energy Line Break Door which is located between the Main Feed Regulating Valve Room and the Auxiliary Boiler Feed Pump Room places the plant in an unanalyzed condition. Maintenance is fabricating a metal replacement part to cover the opening. The door is supposed to remain closed at all times when the plant is above 350 degrees F.

The NRC Resident Inspector will be notified of this event by the licensee.

* * * RETRACTION 1259 1/27/2000 TAKEN BY STRANSKY * * *

"Indian Point has performed an engineering evaluation of the broken window in the High Energy Line Break door located between the Main Feed Regulating Valve room and the Auxiliary Boiler Feed Pump room and determined that the equipment in the Auxiliary Boiler Feed Pump room would have maintained its environmental qualification and the plant would have remained in an analyzed condition even if the window was entirely missing. Therefore, this event has been retracted."

The licensee will inform the NRC resident inspector of this retraction. Notified R1DO (Rogge).

Power Reactor	Event Number: 36629

FACILITY: CRYSTAL RIVER UNIT: [3] [] [] RXTYPE: [3] B&W-L-LP	REGION: 2 STATE: FL	NOTIFICATION DATE: 01/27/2000 NOTIFICATION TIME: 11:35[EST] EVENT DATE: 01/27/2000 EVENT TIME: 09:00[EST] LAST UPDATE DATE: 01/27/2000
NRC NOTIFIED BY: BANDHAVER HQ OPS OFFICER: CHAUNCEY GOULD		PERSON: CAUDLE JULIAN ORGANIZATION: R2
EMERGENCY CLASS: N/A 10 CFR SECTION: APRE 50.72(b)(2)(vi) OFFSITE NOTIFICATION		

UNIT	SCRAM CODE	RX CRIT	INIT PWR	INIT RX MODE	CURR PWR	CURR RX MODE
3	N	Y	100	Power Operation	100	Power Operation

EVENT TEXT

OFFSITE NOTIFICATION TO FLORIDA FISH AND WILDLIFE CONSERVATION COMMISSION

A GREEN SEA TURTLE(AN ENDANGERED SPECIES) WAS FOUND IN THE INTAKE. THE TURTLE WILL BE HELD FOR A DAY TO ENSURE ITS HEALTH AND THEN RELEASED IN ACCORDANCE WITH THE FISH AND WILDLIFE CONSERVATION COMMISSION DIRECTIONS.

THE NRC RESIDENT INSPECTOR WILL BE NOTIFIED.

Power Reactor	Event Number: 36630

FACILITY: HATCH UNIT: [1] [] [] RXTYPE: [1] GE-4,[2] GE-4	REGION: 2 STATE: GA	NOTIFICATION DATE: 01/27/2000 NOTIFICATION TIME: 12:09[EST] EVENT DATE: 01/26/2000 EVENT TIME: 22:38[EST] LAST UPDATE DATE: 01/27/2000
NRC NOTIFIED BY: MUSGROVE HQ OPS OFFICER: CHAUNCEY GOULD		PERSON: CAUDLE JULIAN ORGANIZATION: R2
EMERGENCY CLASS: N/A 10 CFR SECTION: AESF 50.72(b)(2)(ii) ESF ACTUATION		

UNIT	SCRAM CODE	RX CRIT	INIT PWR	INIT RX MODE	CURR PWR	CURR RX MODE
1	N	N	0	Hot Shutdown	0	Hot Shutdown

EVENT TEXT

FAILURE OF PRIMARY CONTAINMENT ISOLATION VALVE TO CLOSE ON A LOW REACTOR PRESSURE SIGNAL.

PRIMARY CONTAINMENT ISOLATION VALVE "1E51-F008" DID NOT CLOSE ON A LOW

REACTOR PRESSURE SIGNAL DUE TO INSTRUMENT "1E51-N685C" BEING INOPERABLE. THE OTHER VALVE IN THIS LINE, VALVE "1E51-F007", DID CLOSE TO ISOLATE THE PENETRATION. THE "1E51-F008" VALVE WAS CLOSED AS DIRECTED BY THE SHUTDOWN PROCEDURE "34G0-OPS-013-1S". THIS EVENT IS BEING INVESTIGATED TO DETERMINE THE ROOT CAUSE. THE REPORTABILITY OF THE EVENT WAS NOT DETERMINED AT THE TIME OF THE OCCURRENCE.

THE NRC RESIDENT INSPECTOR WAS NOTIFIED.

[HOO NOTE: SEE RELATED EN 36625.]

Fuel Cycle Facility — Event Number: 36631

FACILITY:	PORTSMOUTH GASEOUS DIFFUSION PLANT	NOTIFICATION DATE:	01/27/2000
RXTYPE:	URANIUM ENRICHMENT FACILITY	NOTIFICATION TIME:	14:12[EST]
COMMENTS:	2 DEMOCRACY CENTER	EVENT DATE:	01/26/2000
	6903 ROCKLEDGE DRIVE	EVENT TIME:	14:45[EST]
	BETHESDA, MD 20817 (301)564-3200	LAST UPDATE DATE:	01/27/2000
CITY:	PIKETON	REGION: 3	
COUNTY:	PIKE	STATE: OH	
LICENSE#:	GDP-2	AGREEMENT: N	
DOCKET:	0707002		

PERSON	ORGANIZATION
MONTE PHILLIPS	R3
	NMSS

NRC NOTIFIED BY: MCCLEERY
HQ OPS OFFICER: CHAUNCEY GOULD

EMERGENCY CLASS: N/A
10 CFR SECTION:
NBNL RESPONSE-BULLETIN

EVENT TEXT

24 HOUR 91-01 BULLETIN RESPONSE

AT APPROXIMATELY 1445 HRS @ 1/26/00, ELEVEN (11) BAGS WITH MISCELLANEOUS CONTENTS WERE DISCOVERED IN THE X-103 HEALTH PHYSICS SOURCE VAULT. THREE (3) OF THE ELEVEN ITEMS CONTAINED GREATER THAN 1% U-235 WITH THE HIGHEST ASSAY BEING 52.1 %. THE TOTAL GRAM CONTENT OF ALL THREE ITEMS INCLUDING ERROR IS 158.5 g U-235 FOR 52% ASSAY (MOST LIMITING). ALL ELEVEN ITEMS WERE PLACED INTO TWO (2) APPROVED CONTAINERS WHICH WERE MOVED TO AN APPROVED STORAGE FACILITY.

THERE WAS NO LOSS OF HAZARDOUS/RADIOACTIVE MATERIAL OR RADIOACTIVE/RADIOLOGICAL CONTAMINATION EXPOSURE AS A RESULT OF THIS EVENT.

THE NRC RESIDENT INSPECTOR WAS NOTIFIED AND THE DOE REPRESENTATIVE WILL BE NOTIFIED

Power Reactor — Event Number: 36632

FACILITY:	COOPER	REGION: 4	NOTIFICATION DATE: 01/27/2000
UNIT:	[1] [] []	STATE: NE	NOTIFICATION TIME: 15:06[EST]

RXTYPE: [1] GE-4	EVENT DATE: 01/27/2000
	EVENT TIME: 11:22[CST]
NRC NOTIFIED BY: FRED SCHIZAS	LAST UPDATE DATE: 01/27/2000
HQ OPS OFFICER: BOB STRANSKY	
	PERSON ORGANIZATION
EMERGENCY CLASS: N/A	GAIL GOOD R4
10 CFR SECTION:	
AESF 50.72(b)(2)(ii) ESF ACTUATION	

UNIT	SCRAM CODE	RX CRIT	INIT PWR	INIT RX MODE	CURR PWR	CURR RX MODE
1	N	Y	100	Power Operation	100	Power Operation

EVENT TEXT

REACTOR WATER CLEANUP ISOLATION WHILE PLACING SYSTEM IN SERVICE

"During initial repressurization of the reactor water cleanup system (RWCU) after the maintenance outage, the control room received channel 'A' and 'B' RWCU high flow alarm (<=191% of rated flow) and subsequent Group 3 isolation (closure of RWCU-MOV-M015 and RWCU-MOV-M018 inboard / outboard primary containment isolation valves). This actuation occurred while the operator was throttling open RWCU-M018.

The Group 3 was verified per G.O.P. 2.1.22 (Recovery From Group Isolations) and following recovery, system flow was restored."

The NRC resident inspector has been informed of this event by the licensee.

Power Reactor	Event Number: 36633

FACILITY: MILLSTONE REGION: 1	NOTIFICATION DATE: 01/27/2000
UNIT: [] [2] [] STATE: CT	NOTIFICATION TIME: 15:10[EST]
RXTYPE: [1] GE-3,[2] CE,[3] W-4-LP	EVENT DATE: 01/27/2000
	EVENT TIME: 14:57[EST]
NRC NOTIFIED BY: STEVE BAKER	LAST UPDATE DATE: 01/27/2000
HQ OPS OFFICER: BOB STRANSKY	
	PERSON ORGANIZATION
EMERGENCY CLASS: N/A	JOHN ROGGE R1
10 CFR SECTION:	
ARPS 50.72(b)(2)(ii) RPS ACTUATION	
AESF 50.72(b)(2)(ii) ESF ACTUATION	

UNIT	SCRAM CODE	RX CRIT	INIT PWR	INIT RX MODE	CURR PWR	CURR RX MODE
2	M/R	Y	100	Power Operation	0	Hot Standby

EVENT TEXT

MANUAL REACTOR TRIP DUE TO SECONDARY SYSTEM TRANSIENT

Operators manually tripped the unit from 100% power due to decreasing steam generator water levels caused by a decrease in feedwater flow. Feedwater

flow decreased due to a transient in a feedwater heater string. All control rods inserted following the trip. Operators also manually initiated the auxiliary feedwater system to restore steam generator water levels (a confirmatory automatic initiation signal was received). The unit is currently stable in Hot Standby. All systems functioned as expected.

The NRC resident inspector has been informed of this event by the licensee.

Power Reactor — Event Number: 36634

FACILITY: SURRY UNIT: [] [2] [] RXTYPE: [1] W-3-LP,[2] W-3-LP	REGION: 2 STATE: VA
NRC NOTIFIED BY: DARLENE BROCK HQ OPS OFFICER: BOB STRANSKY	NOTIFICATION DATE: 01/27/2000 NOTIFICATION TIME: 15:38[EST] EVENT DATE: 01/27/2000 EVENT TIME: 12:01[EST] LAST UPDATE DATE: 01/27/2000
EMERGENCY CLASS: N/A 10 CFR SECTION: AINC 50.72(b)(2)(iii)(C) POT UNCNTRL RAD REL	PERSON — ORGANIZATION CAUDLE JULIAN — R2

UNIT	SCRAM CODE	RX CRIT	INIT PWR	INIT RX MODE	CURR PWR	CURR RX MODE
2	N	Y	100	Power Operation	100	Power Operation

EVENT TEXT

EXCESSIVE LEAKAGE THROUGH CONTAINMENT ISOLATION VALVE

"On 1/27/00 at 1201 hours, as-found 10CFR50 Appendix J Type C leakage testing of the outside containment trip valve 2-DA-TV-200B was determined to be greater than 0.6 La. Leakage was determined to be approximately 182 scfh versus total minimum pathway leakage acceptance criteria of 180 scfh.

"On 1/25/00 the inside containment trip valve 2-DA-TV-200A for the same penetration was replaced due to an unsatisfactory 1ST stroke time. Removal and installation of the valve was less than one hour in duration. Following replacement of the valve, Type C leakage was determined to be satisfactory for 2-DA-TV-200A, however, excessive leakage was suspected for the outside trip valve 2-DA-TV-200B.

"By testing conducted on 1/27/00, it was confirmed that during the timeframe of 2-DA-TV-200A replacement, a condition which alone could have prevented the fulfillment of the safety function needed to control the release of radioactive material existed.

"Currently containment integrity is being maintained by closure and deactivation of 2-DA-TV-200A in accordance with the station Technical Specification. Following replacement of 2-DA-TV-200A on 1/25/00, Type C testing was performed with satisfactory results (less than 1 scfh). Currently total minimum pathway leakage is approximately 3 scfh.

This report is being made pursuant 10CFR50.72(b)(2)(iii)."

The licensee has informed the NRC resident inspector of this event.

Other Nuclear Material	Event Number: 36635

REP ORG: USAF RADIOISOTOPE COMMITTEE LICENSEE: USAF RADIOISOTOPE COMMITTEE CITY: KEESLER AFB REGION: 4 COUNTY: STATE: LA LICENSE#: 42-23539-AF AGREEMENT: Y DOCKET: 03028641	NOTIFICATION DATE: 01/27/2000 NOTIFICATION TIME: 16:51[EST] EVENT DATE: 01/27/2000 EVENT TIME: 15:00[CST] LAST UPDATE DATE: 01/27/2000
NRC NOTIFIED BY: MAJ. HICKS HQ OPS OFFICER: BOB STRANSKY	PERSON ORGANIZATION GAIL GOOD R4 LARRY CAMPER NMSS
EMERGENCY CLASS: N/A 10 CFR SECTION: BAB1 20.2201(a)(1)(i) LOST/STOLEN LNM>1000X	

EVENT TEXT

MISSING CALIBRATION SOURCE

On 1/26/00, the Keesler AFB Radiation Safety Officer (RSO) was unable to locate a 1.37 µCi Pu-239 calibration source during a routine inventory of Wolfe Hall. During the subsequent investigation, the Wolfe Hall RSO reported that the source was to have been transferred to Kelly AFB in Texas, but it had inadvertently been shipped to McLellan AFB in California. However, the McLellan AFB transportation office has no record of receiving the source. The Keesler AFB RSO will continue to attempt to locate the source.

Power Reactor	Event Number: 36636

FACILITY: COMANCHE PEAK REGION: 4 UNIT: [1] [2] [] STATE: TX RXTYPE: [1] W-4-LP,[2] W-4-LP	NOTIFICATION DATE: 01/27/2000 NOTIFICATION TIME: 17:12[EST] EVENT DATE: 01/27/2000 EVENT TIME: 12:50[CST] LAST UPDATE DATE: 01/27/2000
NRC NOTIFIED BY: PAUL COX HQ OPS OFFICER: BOB STRANSKY	PERSON ORGANIZATION GAIL GOOD R4
EMERGENCY CLASS: N/A 10 CFR SECTION: APRE 50.72(b)(2)(vi) OFFSITE NOTIFICATION	

UNIT	SCRAM CODE	RX CRIT	INIT PWR	INIT RX MODE	CURR PWR	CURR RX MODE
1	N	Y	100	Power Operation	100	Power Operation
2	N	Y	100	Power Operation	100	Power Operation

EVENT TEXT

OFFSITE NOTIFICATION DUE TO OIL SHEEN

The licensee notified the Texas Natural Resource Conservation Commission and the US DOT National Response Center regarding the appearance of an oil sheen near the circulating water discharge. The licensee believes that the oil is residue from recent paving activities that has been washed out due to heavy rains. The licensee has deployed absorbent materials to control the spill. The NRC resident inspector has been informed of this event by the licensee.

Power Reactor | Event Number: 36637

FACILITY: SAN ONOFRE REGION: 4	NOTIFICATION DATE: 01/27/2000
UNIT: [] [2] [3] STATE: CA	NOTIFICATION TIME: 19:13[EST]
RXTYPE: [1] W-3-LP,[2] CE,[3] CE	EVENT DATE: 01/27/2000
	EVENT TIME: 15:30[PST]
NRC NOTIFIED BY: A. BOLYEN	LAST UPDATE DATE: 01/27/2000
HQ OPS OFFICER: BOB STRANSKY	
	PERSON ORGANIZATION
EMERGENCY CLASS: N/A	GAIL GOOD R4
10 CFR SECTION:	
AOUT 50.72(b)(1)(ii)(B) OUTSIDE DESIGN BASIS	

UNIT	SCRAM CODE	RX CRIT	INIT PWR	INIT RX MODE	CURR PWR	CURR RX MODE
2	N	Y	100	Power Operation	100	Power Operation
3	N	Y	100	Power Operation	100	Power Operation

EVENT TEXT

UNITS OUTSIDE OF DESIGN BASIS DUE TO WORDING OF UFSAR

"This notification is for San Onofre Units 2 and 3 and is being made in accordance with 10CFR50.72(b)(1)(ii)(B).

"Southern California Edison was performing a review of plant drawings and noticed a potential discrepancy between some circuit designs and the specific wording used in the Updated Final Safety Analysis Report (UFSAR) to describe the design for those circuits. Further investigation of the affected components revealed that certain functions appear to not fully meet the separation criteria of Regulatory Guide 1.75, 'Physical Independence of Electrical Systems.' These circuits include relays for portions of some Engineered Safety Features (e.g., boric acid makeup pumps and input voltage to one of the four loss-of-voltage-signal circuits). The UFSAR for Units 2 and 3 indicates these systems comply with IEEE-279, 1971, 'Criteria for Protection Systems for Nuclear Power Generation Stations' which is referenced by Regulatory Guide 1.75. Consequently, at 1530 PDT, SCE concluded this condition was reportable in accordance with 10CFR50.72(b)(1)(ii)(B) as a condition 'outside the design basis of the plant.'

"SCE has confirmed that the affected components remain capable of performing their intended safety functions and, therefore, concludes there is no safety significance to this occurrence.

"At the time of this report. Unit 1 remains permanently shutdown, and Units 2 and 3 are operating at about 100% power. SCE will notify the NRC resident inspectors of this condition and provide them with a copy of this report."

Power Reactor	Event Number: 36638

FACILITY: QUAD CITIES	REGION: 3	NOTIFICATION DATE: 01/28/2000
UNIT: [] [2] []	STATE: IL	NOTIFICATION TIME: 05:14[EST]
RXTYPE: [1] GE-3,[2] GE-3		EVENT DATE: 01/28/2000
		EVENT TIME: 02:40[CST]
NRC NOTIFIED BY: DARYL CLARK		LAST UPDATE DATE: 01/28/2000
HQ OPS OFFICER: STEVE SANDIN		

EMERGENCY CLASS: N/A	PERSON ORGANIZATION
10 CFR SECTION:	MONTE PHILLIPS R3
AIND 50.72(b)(2)(iii)(D) ACCIDENT MITIGATION	

UNIT	SCRAM CODE	RX CRIT	INIT PWR	INIT RX MODE	CURR PWR	CURR RX MODE
2	N	N	0	Refueling	0	Refueling

EVENT TEXT

BOTH EMERGENCY DIESEL GENERATORS INOPERABLE DURING CORE ALTERATIONS

"On 1/28/00 at 0005 hrs. the U- 2 Emergency Diesel Generator was found to be inoperable due to the diesel generator room vent fan selector switch being selected to the alternate feed. The 1/2 Emergency Diesel Generator was inoperable due to Division I electrical system refuel outage work. Core alterations were in progress.

"Per Tech Spec 3.9.B, one diesel generator must be operable in Mode 5, and when handling irradiated fuel in the secondary containment.

"The switch was aligned to the normal position and vent fan operation was verified within approximately 15 minutes to restore the U-2 diesel generator to an operable status. An internal investigation is commencing. Although both the 1/2 and U-2 EDGs were inoperable, both diesels remained available for operation.

"This event is being reported as required by 10CFR50.72(b)(2)(iii)(D), an event which alone could have prevented the fulfillment of a safety function needed to mitigate the consequences of an accident."

The licensee informed the NRC Resident Inspector.

Daily Events Report

U.S. Nuclear Regulatory Commission
Operations Center

Event Reports For
02/11/2000 - 02/14/2000

** EVENT NUMBERS **

36665 36667 36679 36680 36681 36682 36683 36684 36685 36686

!!!!!!!! THIS EVENT HAS BEEN RETRACTED. THIS EVENT HAS BEEN RETRACTED !!!!!!!

Power Reactor	Event Number: 36665

FACILITY: HATCH	REGION: 2	NOTIFICATION DATE: 02/06/2000
UNIT: [1] [2] []	STATE: GA	NOTIFICATION TIME: 18:37[EST]
RXTYPE: [1] GE-4,[2] GE-4		EVENT DATE: 02/06/2000
		EVENT TIME: 17:55[EST]
NRC NOTIFIED BY: BRUCE BUTLER		LAST UPDATE DATE: 02/11/2000
HQ OPS OFFICER: JOHN MacKINNON		

EMERGENCY CLASS: N/A	PERSON	ORGANIZATION
10 CFR SECTION:	KERRY LANDIS	R2
AARC 50.72(b)(1)(v) OTHER ASMT/COMM INOP		

UNIT	SCRAM CODE	RX CRIT	INIT PWR	INIT RX MODE	CURR PWR	CURR RX MODE
1	N	Y	93	Power Operation	93	Power Operation
2	N	Y	98	Power Operation	98	Power Operation

EVENT TEXT

PUBLIC PROMPT NOTIFICATION SYSTEM INOPERABLE FOR 2 MINUTES

Due to technical difficulties in Jacksonville, Florida, the Public Prompt Notification System (NOAA weather radio) was lost at 1755 ET and was restored to service at 1757 ET. Primary and backup system were inoperable during this period of time.

The NRC Resident will be notified of this event notification by the licensee.

* * * UPDATE AT 1420 ON 02/11/00 BY TIM BEINKE TO JOLLIFFE * * *

The licensee desires to retract this event in accordance with the guidance contained in NRC NUREG-1022 since the Public Prompt Notification System was inoperable for less than 15 minutes.

The licensee plans to notify the NRC Resident Inspector.

The NRC Operations Officer notified the R2DO Mark Lesser.

!!!!!!!! THIS EVENT HAS BEEN RETRACTED. THIS EVENT HAS BEEN RETRACTED !!!!!!!

Power Reactor	Event Number: 36667

A/7

FACILITY: DRESDEN REGION: 3 UNIT: [1] [2] [] STATE: IL RXTYPE: [1] GE-1,[2] GE-3,[3] GE-3	NOTIFICATION DATE: 02/07/2000 NOTIFICATION TIME: 04:28[EST] EVENT DATE: 02/07/2000 EVENT TIME: 02:40[CST] LAST UPDATE DATE: 02/11/2000
NRC NOTIFIED BY: DAVE KLIMECK HQ OPS OFFICER: DOUG WEAVER	PERSON ORGANIZATION TONY VEGEL R3
EMERGENCY CLASS: N/A 10 CFR SECTION: DDDD 73.71 UNSPECIFIED PARAGRAPH	

UNIT	SCRAM CODE	RX CRIT	INIT PWR	INIT RX MODE	CURR PWR	CURR RX MODE
1	N	Y	100	Power Operation	100	Power Operation
2	N	Y	100	Power Operation	100	Power Operation

EVENT TEXT

Minimum security personnel staffing requirements not met. Immediate compensatory actions taken upon discovery. The licensee will notify the NRC resident inspector. Additional details of this event may be obtained by contacting the NRC operations officer.

* * * UPDATE AT 2057 ON 02/11/00 BY CHRIS KENT TO JOLLIFFE * * *

The licensee desires to retract this event since the commitments in the approved Plant Physical Security Plan had been complied with during this event. The licensee plans to notify the NRC Resident Inspector. The NRC Operations Officer notified the R3DO Mike Parker. Additional details of this event retraction may be obtained by contacting the NRC Operations Officer.

Power Reactor	Event Number: 36679

FACILITY: CATAWBA REGION: 2 UNIT: [1] [2] [] STATE: SC RXTYPE: [1] W-4-LP,[2] W-4-LP	NOTIFICATION DATE: 02/11/2000 NOTIFICATION TIME: 00:59[EST] EVENT DATE: 02/10/2000 EVENT TIME: 18:50[EST] LAST UPDATE DATE: 02/11/2000
NRC NOTIFIED BY: BROWN HQ OPS OFFICER: CHAUNCEY GOULD	PERSON ORGANIZATION MARK LESSER R2
EMERGENCY CLASS: N/A 10 CFR SECTION: NLTR LICENSEE 24 HR REPORT NLCO TECH SPEC LCO A/S	

UNIT	SCRAM CODE	RX CRIT	INIT PWR	INIT RX MODE	CURR PWR	CURR RX MODE
1	N	Y	100	Power Operation	100	Power Operation
2	N	Y	100	Power Operation	100	Power Operation

EVENT TEXT

THE LICENSEE SUBMITTED A 24 HOUR OPERATING LICENSE DEVIATION REPORT.

While performing the Penetration Seal Firestop Configuration verification project, engineering determined that 37 firestop penetrations are not configured in accordance with existing approved details. Therefore, these 37 penetrations are not operable, putting the plant in a LCO action statement. Remedial action has been taken per Selected License Commitment 16.9-5 Fire Barrier Penetrations, this action establishes hourly fire watches on each affected penetration.

The NRC Resident Inspector was notified.

Power Reactor — Event Number: 36680

FACILITY: QUAD CITIES	REGION: 3	NOTIFICATION DATE:	02/11/2000
UNIT: [] [2] []	STATE: IL	NOTIFICATION TIME:	07:13[EST]
RXTYPE: [1] GE-3,[2] GE-3		EVENT DATE:	02/11/2000
		EVENT TIME:	02:58[CST]
NRC NOTIFIED BY: OSELAND		LAST UPDATE DATE:	02/11/2000
HQ OPS OFFICER: CHAUNCEY GOULD			

EMERGENCY CLASS: N/A	PERSON — ORGANIZATION
10 CFR SECTION:	MICHAEL PARKER — R3
AIND 50.72(b)(2)(iii)(D) ACCIDENT MITIGATION	
NLCO TECH SPEC LCO A/S	

UNIT	SCRAM CODE	RX CRIT	INIT PWR	INIT RX MODE	CURR PWR	CURR RX MODE
2	N	Y	4	Startup	4	Startup

EVENT TEXT

HPCI DECLARED INOPERABLE, PLACING THE PLANT IN A LCO ACTION STATEMENT.

On 2/11/2000 at 0258 hours, HPCI low pressure operability testing was in progress following a scheduled refueling outage. At that time, the HPCI turbine failed to roll when the motor speed changer was taken to its high speed stop. There was no change in steam flow as indicated by the main turbine bypass valve position. The operator in attendance visually verified HPCI was still on the turning gear. The surveillance was terminated and the system restored to standby lineup. At 0341 hours, reactor pressure was reduced below 150 psig to place the reactor in a condition where HPCI was not required to be operable, and they exited the LCO at that time.

The cause of this failure is under investigation.

The NRC Resident Inspector was notified.

Hospital — Event Number: 36681

REP ORG: JASPER COUNTY HOSPITAL		NOTIFICATION DATE:	02/11/2000
LICENSEE: JASPER COUNTY HOSPITAL		NOTIFICATION TIME:	10:45[EST]
CITY: RENSSELAER	REGION: 3	EVENT DATE:	02/11/2000
COUNTY:	STATE: IN	EVENT TIME:	08:45[CST]
LICENSE#: 13-26527-01	AGREEMENT: N	LAST UPDATE DATE:	02/11/2000
DOCKET:			

PERSON	ORGANIZATION
JAMES CREED	R3
BRIAN SMITH	NMSS

NRC NOTIFIED BY: ROTH
HQ OPS OFFICER: CHAUNCEY GOULD

EMERGENCY CLASS: N/A
10 CFR SECTION:
BAAA 20.1906(d) SURFACE CONT/ EXT RAD

EVENT TEXT

JASPER COUNTY HOSPITAL RECEIVED A SURFACE CONTAMINATED BOX WHICH CONTAINED NUCLEAR MEDICINE.

A METAL AMMO BOX USED TO TRANSPORT NUCLEAR MEDICINE CONTAINED IN INDIVIDUAL PIGS WAS FOUND TO HAVE SURFACE TECHNICIUM CONTAMINATION ON THE LOCKING CLASP MEASURING 604 DPM/CM2 (LIMIT IS EQUAL TO OR LESS THAN 220 DPM/CM2). THERE WAS NO DAMAGE TO THE PIG CONTAINERS INSIDE THE AMMO BOX AND NO CONTAMINATION WAS MEASURED INSIDE THE BOX. THE SOURCE OF THE CONTAMINATION IS UNKNOWN, BUT IT COULD HAVE OCCURRED AT THE PHARMACEUTICAL COMPANY, THE TRANSPORTER OR IN THE HOSPITAL LABORATORY. HOSPITAL PERSONNEL HAVE ISOLATED THE AMMO BOX AND WILL ALLOW THE TECHNICIUM CONTAMINATION TO DECAY OFF.

(CALL THE NRC OPERATIONS OFFICER FOR A LICENSEE CONTACT TELEPHONE NUMBER.)

Power Reactor — Event Number: 36682

FACILITY: MILLSTONE REGION: 1
UNIT: [] [2] []
RXTYPE: [1] GE-3,[2] CE,[3] W-4-LP

NOTIFICATION DATE: 02/11/2000
NOTIFICATION TIME: 14:32[EST]
EVENT DATE: 02/11/2000
EVENT TIME: 13:46[EST]
LAST UPDATE DATE: 02/11/2000

NRC NOTIFIED BY: MIKE BAIN
HQ OPS OFFICER: DICK JOLLIFFE

PERSON	ORGANIZATION
HAROLD GRAY	R1

EMERGENCY CLASS: N/A
10 CFR SECTION:
ARPS 50.72(b)(2)(ii) RPS ACTUATION
AESF 50.72(b)(2)(ii) ESF ACTUATION

UNIT	SCRAM CODE	RX CRIT	INIT PWR	INIT RX MODE	CURR PWR	CURR RX MODE
2	M/R	Y	96	Power Operation	0	Hot Standby

EVENT TEXT

- MANUAL REACTOR TRIP FROM 96% POWER AFTER 2 CONTROL RODS DROPPED INTO THE CORE -

During the performance of a tech spec surveillance test of control rod motion with Unit 2 at 100% power, one control rod dropped into the core for unknown reasons. Control room operators reduced power. With Unit 2 at 96%

power, a second control rod dropped into the core for unknown reasons. Control room operators manually tripped Unit 2 from 96% power. All control rods inserted completely into the core. The auxiliary feedwater system actuated, as expected. Control room operators manually secured the auxiliary feedwater system. Steam generator water levels are being maintained in their normal range by the main feedwater system. Steam is being dumped to the main condenser. No safety or relief valves lifted. Unit 2 is stable in Mode 3 (Hot Standby). The licensee is investigating the cause of the control rods dropping into the core.

The licensee notified state and local officials and the NRC Resident Inspector and plans to issue a press release.

Fuel Cycle Facility — Event Number: 36683

FACILITY: PORTSMOUTH GASEOUS DIFFUSION PLANT	NOTIFICATION DATE: 02/11/2000
RXTYPE: URANIUM ENRICHMENT FACILITY	NOTIFICATION TIME: 16:27[EST]
COMMENTS: 2 DEMOCRACY CENTER	EVENT DATE: 02/10/2000
6903 ROCKLEDGE DRIVE	EVENT TIME: 23:30[EST]
BETHESDA, MD 20817 (301)564-3200	LAST UPDATE DATE: 02/11/2000
CITY: PIKETON REGION: 3	
COUNTY: PIKE STATE: OH	PERSON ORGANIZATION
LICENSE#: GDP-2 AGREEMENT: N	JAMES CREED R3
DOCKET: 0707002	JOSEPHINE PICCONE NMSS

NRC NOTIFIED BY: RICK LARSON
HQ OPS OFFICER: DICK JOLLIFFE

EMERGENCY CLASS: N/A
10 CFR SECTION:
NBNL RESPONSE-BULLETIN

EVENT TEXT

NRC Bulletin 91-01, 24 Hour Report - Loss of 1 of 2 Controlled Parameters (Geometry) -

At 2330 on 02/10/00, the Plant Shift Superintendent (PSS) was notified that a Nuclear Criticality Safety Approval (NCSA) requirement was not being maintained in the X-705 decontamination facility. While performing an NCS Self Assessment, facility personnel noticed an operation where requirements for the control of "Inadvertent Containers" was not being met. The Inadvertent container was a rectangular support structure for a ventilator that was approximately 5.5 inches deep and did not have any holes or slots to provide drainage. The critical height dimension is 1.5 inches from the bottom of the container.

Requirement #5 of NCSA-0705-076.A00 states, in part that modifications to inadvertent containers, where practical, shall be accomplished by drilling holes or making slots in the container to provide drainage. This structure, not having drainage holes, was a loss of one control (geometry). The other control (concentration) was maintained.

At the direction of the PSS, the requirements for an NCS anomalous condition were established per plant procedures. At approximately 0130 on 02/11/00, double contingency controls were reestablished.

SAFETY SIGNIFICANCE OF THE EVENT:

The safety significance of this event is low. The inadvertent container is an iron support structure for a ventilator that is approximately 5.5 inches deep by 24 inches wide and just over 60 inches long. This structure is in the high bay of the X-705 building bolted to the floor under the overhead storage system. However, there were no indications that any solution had collected in the container or that any leakage had occurred from the overhead storage in this area. Also, data on the concentration of uranium in the overhead storage indicates that it is currently less than 500 ppm.

POTENTIAL CRITICALITY PATHWAYS INVOLVED [BRIEF SCENARIO(S) OF HOW CRITICALITY COULD OCCUR]:

The potential pathway for a criticality is a failure of the overhead storage system. This would allow uranium bearing solution to collect in the container. Since the container has a depth greater than the safe slab depth of 1.5 inches for 100% enriched material, a criticality could occur if the collected solution's depth exceeds 1.5 inches and the uranium concentration of the solution exceeds 11,600 ppm.

CONTROLLED PARAMETERS (MASS, MODERATION, GEOMETRY. CONCENTRATION, ETC.):

The parameters being controlled are geometry (container geometry and overhead storage piping) and concentration of solution in the overhead storage.

ESTIMATED AMOUNT, ENRICHMENT, FORM OF LICENSED MATERIAL (INCLUDE PROCESS LIMIT AND PER CENT WORST CASE OF CRITICAL MASS):

There was no uranium material involved with this event. If the overhead storage were to leak, the enrichment is considered to be 100% and the form would be U02F2 solution (worst case).

NUCLEAR CRITICALITY SAFETY CONTROL(S) OR CONTROL SYSTEM(S) AND DESCRIPTION OF THE FAILURES OR DEFICIENCIES:

The geometry control of container was lost. The NCSA requires that holes or slots be added to the container to limit the height of the solution that could collect to less than 1.5 inches.

CORRECTIVE ACTIONS TO RESTORE SAFETY SYSTEM AND WHEN EACH WAS IMPLEMENTED:

Compliance was regained at 0130 on 02/11/00 when plastic has placed over the container to prevent the introduction of solution.

There was no loss of hazardous or radioactive material nor radioactive or radiological contamination exposure as a result of this event.

Portsmouth personnel notified the NRC Resident Inspector and the Site DOE Representative.

PTS-2000-009 PR-PTS-00-00829

Power Reactor	Event Number: 36684

FACILITY: COOPER	REGION: 4	NOTIFICATION DATE: 02/11/2000
UNIT: [1] [] []	STATE: NE	NOTIFICATION TIME: 20:13[EST]
RXTYPE: [1] GE-4		EVENT DATE: 02/11/2000
		EVENT TIME: 17:07[CST]
NRC NOTIFIED BY: STEVE WHEELER		LAST UPDATE DATE: 02/11/2000
HQ OPS OFFICER: DICK JOLLIFFE		

EMERGENCY CLASS: N/A 10 CFR SECTION: APRE 50.72(b)(2)(vi) OFFSITE NOTIFICATION					PERSON LINDA HOWELL	ORGANIZATION R4
UNIT	SCRAM CODE	RX CRIT	INIT PWR	INIT RX MODE	CURR PWR	CURR RX MODE
1	N	Y	100	Power Operation	100	Power Operation

EVENT TEXT

- Nebraska Game and Parks Department notified of a dead American Bald Eagle found onsite -

At 1707 CST on 02/11/00, a licensee employee found an American Bald Eagle under a 345 kV line on licensee property. The licensee notified the Nebraska Game and Parks Department. A Nebraska Game Warden reported to the site and took possession of the eagle. The warden stated that the eagle had been dead for some time. The warden plans to notify the Fish and Wildlife Service of this incident and to send the bird to them.

The licensee notified the NRC Resident Inspector.

Power Reactor					Event Number: 36685	
FACILITY: CALLAWAY UNIT: [1] [] [] RXTYPE: [1] W-4-LP				REGION: 4 STATE: MO	NOTIFICATION DATE: 02/13/2000 NOTIFICATION TIME: 11:11[EST] EVENT DATE: 02/13/2000 EVENT TIME: 07:34[CST] LAST UPDATE DATE: 02/13/2000	
NRC NOTIFIED BY: ROBERT BARTON HQ OPS OFFICER: STEVE SANDIN						
EMERGENCY CLASS: N/A 10 CFR SECTION: ARPS 50.72(b)(2)(ii) RPS ACTUATION AESF 50.72(b)(2)(ii) ESF ACTUATION					PERSON LINDA HOWELL	ORGANIZATION R4
UNIT	SCRAM CODE	RX CRIT	INIT PWR	INIT RX MODE	CURR PWR	CURR RX MODE
1	A/R	Y	100	Power Operation	0	Hot Standby

EVENT TEXT

AUTOMATIC REACTOR TRIP ON LOSS OF REACTOR COOLANT SYSTEM (RCS) FLOW

THE UNIT EXPERIENCED AN AUTOMATIC REACTOR TRIP-TURBINE TRIP FROM 100% POWER DUE TO THE LOSS OF RCS FLOW CAUSED BY THE TRIP OF THE REACTOR COOLANT PUMPS (INITIALLY "B" RCP FOLLOWED BY THE "A", "C" AND "D"). FLUCTUATING GRID VOLTAGE DUE TO AN ELECTRICAL PROBLEM IN SOUTHEAST MISSOURI CAUSED THE LOSS OF THE RCPs AND THE OPERATING CIRCULATING WATER (CW) PUMPS. DURING THE PERIOD TIME BEFORE THE RCPs WERE RESTARTED, RCS PRESSURE INCREASED CAUSING ONE (1) PRESSURIZER PORV TO LIFT AND RESEAT (SETPOINT 2335 PSIG - PRIMARY SAFETY SETPOINT IS 2485 PSIG). A SLIGHT INCREASE IN THE PRESSURIZER RELIEF

TANK PRESSURE WAS OBSERVED. A FEEDWATER ISOLATION SIGNAL OCCURRED WITH ALL SYSTEMS FUNCTIONING AS EXPECTED INCLUDING AUTOSTART OF ALL AUXILIARY FEEDWATER PUMPS (BOTH MOTOR-DRIVEN AND THE TURBINE-DRIVEN PUMPS). CONDENSER VACUUM WAS LOST AS A RESULT OF THE CW PUMP TRIPS. HOWEVER, TWO (2) CW PUMPS WERE RESTARTED AND THE MAIN CONDENSER PLACED BACK IN SERVICE AS THE HEAT SINK. THE LICENSEE ESTIMATES THAT THE STEAM GENERATOR ATMOSPHERIC DUMPS WERE USED FOR NO MORE THAN 20 MINUTES DURING THE PERIOD OF TIME WHEN THE MAIN CONDENSER WAS NOT AVAILABLE. THERE IS NO INDICATION OF ANY PRIMARY-SECONDARY LEAKAGE PRIOR TO THIS EVENT. THE PLANT IS CURRENTLY STABLE WITH OPERATORS RESTORING MAIN FEEDWATER. BOTH EMERGENCY DIESELS ARE IN STANDBY AND AVAILABLE, IF NEEDED. THE UNIT WILL REMAIN IN MODE 3 PENDING THE OUTCOME OF THE INVESTIGATION INTO THE GRID ELECTRICAL TRANSIENT.

THE LICENSEE INFORMED THE NRC RESIDENT INSPECTOR.

Power Reactor	Event Number: 36686

FACILITY: CATAWBA	REGION: 2	NOTIFICATION DATE: 02/13/2000
UNIT: [1] [] []	STATE: SC	NOTIFICATION TIME: 19:56[EST]
RXTYPE: [1] W-4-LP,[2] W-4-LP		EVENT DATE: 02/13/2000
		EVENT TIME: 18:32[EST]
NRC NOTIFIED BY: J. K. McCONNELL		LAST UPDATE DATE: 02/13/2000
HQ OPS OFFICER: LEIGH TROCINE		

EMERGENCY CLASS:	N/A	PERSON	ORGANIZATION
10 CFR SECTION:		MARK LESSER	R2
ARPS 50.72(b)(2)(ii)	RPS ACTUATION		
AESF 50.72(b)(2)(ii)	ESF ACTUATION		

UNIT	SCRAM CODE	RX CRIT	INIT PWR	INIT RX MODE	CURR PWR	CURR RX MODE
1	A/R	Y	100	Power Operation	0	Hot Standby

EVENT TEXT

AUTOMATIC REACTOR TRIP DUE TO A TURBINE TRIP FOR UNKNOWN REASONS

The following text is a portion of a facsimile received from the licensee:

"Unit 1 reactor trip occurred at 1832 hours on 02/13/2000. Control room annunciators indicate that the cause of the reactor trip was a turbine trip. At this time, the cause of the turbine trip is unknown. All systems and plant responses to the reactor trip were normal."

The licensee stated that all control rods fully inserted and that all support systems functioned correctly. None of the primary or secondary system safety relief valves lifted. There were no emergency core cooling system actuations, and none were required. The following three engineered safety feature actuations occurred: turbine trip (for unknown reasons), feedwater isolation, and auxiliary feedwater automatic start. Feedwater isolated and auxiliary feedwater automatically started as designed.

The cause of the turbine trip is unknown but is currently believed to be electrical in nature. There were no related maintenance or surveillance activities ongoing at the time of the event.

The unit is currently stable in Mode 3 (Hot Standby). Normal charging and letdown, pressurizer heaters and sprays, and the reactor coolant pumps are

being utilized at this time for primary system level, pressure, and transport control. Auxiliary feedwater is supplying water to the steam generators, and secondary steam is being dumped to the condenser. The electrical grid is stable. The licensee notified the NRC resident inspector.

February 1, 2000

EA No. 00-003

Mr. Stephen E. Scace, Director
Nuclear Oversight and Regulatory Affairs
c/o Mr. D. A. Smith, Manager - Regulatory Affairs
Northeast Nuclear Energy Company
P.O. Box 128
Waterford, Connecticut 06385

SUBJECT: NRC COMBINED INSPECTION 05000336/99014 and 05000423/99014

Dear Mr. Scace:

On January 3, 2000, the NRC completed an inspection at Millstone Units 2 & 3 reactor facilities. The enclosed report presents the results of that inspection.

During the six-weeks covered by this inspection period, your conduct of activities at the Millstone facilities was generally characterized by safety-conscious operations, sound engineering and maintenance practices, and careful radiological work controls. Both units remained at power, in operational Mode 1, throughout the inspection period.

Based on the results of this inspection, the NRC identified two Level IV violations of NRC requirements, one of which related to the Unit 3 procedural violation involving the erection of scaffolding without the requisite engineering review to ensure that seismic interactions would not adversely impact the operability of nearby safety-related equipment. The other example involved a Unit 2 Maintenance Rule violation (10 CFR 50.65(a)(1)) associated with repetitive functional failures of the reactor protection system that our inspectors identified. In addition, the NRC determined that six Level IV violations of NRC requirements, which were associated with conditions that are described in Licensee Event Reports, occurred prior to 1999. All of these violations are being treated as Non-Cited Violations (NCVs), consistent with Section VII.B.1.a of the NRC Enforcement Policy. The NCVs are described in the subject inspection report. If you contest the violation or severity level of these NCVs , you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Millstone facility.

Accession # ML003679593
A/8
IE06

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosures will be placed in the NRC Public Document Room (PDR).

Sincerely,

ORIGINAL SIGNED BY:

James C. Linville, Director
Millstone Inspection Directorate
Office of the Regional Administrator
Region I

Docket Nos. 05000336 and 05000423
License Nos. DPR-21, DPR-65, NPF-49

Enclosure: NRC Combined Inspection Report 05000336/99014 and 05000423/99014

cc w/encl:
B. D. Kenyon, President and Chief Executive Officer - NNECO
L. J. Olivier, Senior Vice President and Chief Nuclear Officer - Millstone
M. H. Brothers, Vice President - Nuclear Operations
F. C. Rothen, Vice President - Nuclear Work Services
R. P. Necci, Vice President - Nuclear Technical Services
J. T. Carlin, Vice President - Human Services
G. D. Hicks, Director - Nuclear Training Services
C. J. Schwarz, Station Director
L. M. Cuoco, Senior Nuclear Counsel
J. R. Egan, Esquire
N. Burton, Esquire
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J. Buckingham, Department of Public Utility Control
State of Connecticut SLO Designee
First Selectmen, Town of Waterford
D. Katz, Citizens Awareness Network (CAN)
T. Concannon, Co-Chair, NEAC
R. Bassilakis, CAN
J. M. Block, Attorney, CAN
G. Winslow, Citizens Regulatory Commission (CRC)
E. Woollacott, Co-Chair, NEAC

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DATE	1/27/00				2/1/00	

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U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket Nos.:	05000336	05000423
Report Nos.:	99014	99014
License Nos.:	DPR-65	NPF-49

Licensee: Northeast Nuclear Energy Company
P. O. Box 128
Waterford, CT 06385

Facility: Millstone Nuclear Power Station, Units 2 and 3

Inspection at: Waterford, CT

Dates: November 23, 1999 - January 3, 2000

Inspectors:
D. P. Beaulieu, Senior Resident Inspector, Unit 2
A. C. Cerne, Senior Resident Inspector, Unit 3
P. C. Cataldo, Resident Inspector, Unit 1
S. R. Jones, Resident Inspector, Unit 2
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EXECUTIVE SUMMARY

Millstone Nuclear Power Station
Combined Inspection 50-336/99-14; 50-423/99-14

Operations

- The established Unit 3 operational and radiological controls were adequate to provide for the safe implementation of plant evolutions and control room activities, as well as for the effective handling and tracking of plant equipment status. Issues involving component operability, availability, reportability, and regulatory compliance were appropriately addressed by the licensee staff. (Section U3.O1.1)

Maintenance

- At Unit 2, the overall conduct of the maintenance and surveillance activities was found acceptable. However, the NRC identified that although the on-line maintenance procedure specified that Operations Manager approval was needed when the planned removal of equipment from service placed the plant in an "Orange" risk condition, the plant staff had not been documenting his approval. Because the Operations Manager was aware of the "Orange" conditions, he had approved the conditions. Therefore, no violation occurred. The licensee's corrective action, which involved changing the on-line maintenance procedure to remove the statement regarding Operations Manager approval, was found acceptable. (Section U2.M1.1)

- At Unit 2, the licensee failed to recognize that the established performance criteria of no repetitive functional failures for the reactor protection system was exceeded on May 28, 1999, and again exceeded in October and November 1999, when another three functional failures occurred. The licensee failed to place the system into an (a)(1) status and establish goals commensurate with safety in violation of 10 CFR 50.65(a)(1). This violation is being treated as a Non-Cited Violation, consistent with section VII.B.1.a of the NRC Enforcement Policy. (NCV 50-336/99-14-01). (Section U2.M1.2)

- At Unit 2, the NRC concluded that the licensee's determination of continued operability of the reactor protection system, despite some degradation, was adequately founded. The majority of issues pose only a minimal increase in the probability of an inadvertent reactor trip or a distraction to the control operators and have no effect on the system's safety function. The licensee has implemented or scheduled appropriate measures to address the degraded conditions consistent with their importance to safety. However, the licensee was untimely in developing a plan to address recurrent instances where an RPS channel was rendered inoperable due to a drifting thermal margin/low pressure setpoint. This untimeliness related to a violation described in Section U2 M8.2, where the NRC found that the licensee failed to identify that system performance goals with respect to maintenance preventable functional failures, which were established by the licensee pursuant to 10 CFR 50.65, had not been met. (Section U2.M1.3)

- At Unit 2, the licensee identified in 1998 that the technical specification (TS) required, ASME code visual tests, had not been performed on portions of safety injection

recirculation header piping. This is a violation of Unit 2 TS 4.0.5. The licensee's corrective actions were found acceptable. This violation of TS 4.0.5, is being treated as a Non-Cited Violation (NCV 50-336/99-14-02). LER 50-336/98-20-00 is closed. (Section U2.M8.3)

- At Unit 2, the licensee identified in 1998 that the technical specification (TS) required containment air recirculation fan start testing, had historically not been performed. This is a violation of TS 4.6.2.1.2. The licensee's corrective actions were found acceptable. This violation of TS 4.6.2.1.2, is being treated as a Non-Cited Violation (NCV 50-336/99-14-03). LER 50-336/98-23-00 is closed. (Section U2.M8.4)

- At Unit 2, the licensee identified in 1998 that the technical specification (TS) required check valve full flow tests had not been performed in accordance with ASME Section XI requirements, on specific check valves. This is a violation of TS 4.0.5. The licensee's corrective actions were found acceptable. This violation of TS 4.0.5, is being treated as a Non-Cited Violation (NCV 50-336/99-14-04). LER 50-336/98-25-00 is closed. (Section U2.M8.5)

- Review of the licensee's work control procedures governing the erection of scaffolding identified adequate controls and engineering directions. However, some Unit 3 scaffolding was identified by NRC field inspection to be in violation of procedural provisions for ensuring that seismic interactions would not impact the operability of nearby safety-related equipment. This failure to follow procedures is being treated as a Non-Cited Violation (NCV 50-423/99-14-08). (Section U3.M2.1)

- At Unit 3, an unresolved item is being opened to allow further NRC evaluation of whether a violation of 10 CFR 50.65(a)(1) and (a)(2) occurred with respect to: (1) the licensee's methods for establishing performance measures for high risk significant structures, systems and components; (2) failure of the licensee to place the station blackout (SBO) diesel in an (a)(1) status and to establish appropriate goals in the general time frame of April 13, 1999, following the second functional failure; (3) the licensee's method of establishing performance measures for the emergency diesel generators and SBO diesel (Unresolved Item 50-423/99-14-09). IFI 50-423/98-02-03 is closed. (Section U3.M8.3)

Engineering

- At Unit 2, the licensee identified in 1998 that certain safety-related cable trays and cables did not meet design basis requirements for separation and/or placement. The licensee's corrective actions were found acceptable. This violation of 10 CFR 50, Appendix B, Criterion III, Design Control, is being treated as a Non-Cited Violation (NCV 50-336/99-14-05). LER 50-336/98-18-00 & 01 are closed. (Section U2.E8.2)

- At Unit 2, the licensee identified in 1998 that certain containment pressure instruments did not meet design basis requirements for post loss of coolant accident pressure retention. The licensee's corrective actions were found acceptable. This violation of 10

CFR 50, Appendix B, Criterion III, Design Control, is being treated as a Non-Cited Violation (NCV 50-336/99-14-06). LER 50-336/98-24-00 is closed. (Section U2.E8.4)

- At Unit 2, the licensee identified in 1998 that pressurizer spray line operating procedures and practices did not meet the design basis requirements for reheating, maximum spray flow and other parameters affecting thermal fatigue parameters for the pressurizer spray line. The licensee's corrective actions were found acceptable. This violation of 10 CFR 50, Appendix B, Criterion III, Design Control is being treated as a Non-Cited Violation (NCV 50-336/99-14-07). LER 50-336/98-26-00 is closed. (Section U2.E8.5)

- The licensee system engineer appropriately conducted follow-up of observed corrosion on some safety-related Unit 3 valves. Material engineers evaluated the as-found conditions in the plant, determined that the immediate, adverse safety impact was minimal, and recommended a solution to eliminate further corrosion as a longer term corrective action. Overall licensee response to this issue was good. (Section U3.E1.1)

Plant Support

- Security and safeguards activities were conducted in a manner that protected public health and safety in the areas of access authorization, alarm stations, and protected area access control of personnel and packages. This portion of the program, as implemented, met the licensee's commitments and NRC requirements. A weakness was identified in the effectiveness of the security communications system. This weakness has been entered in the licensee's corrective action program. (Section S1)

- Protected area assessment aids, protected area detection aids, and personnel search equipment were determined to be well maintained and able to meet the licensee's commitments and NRC requirements. (Section S2)

- Security and safeguards procedures and documentation were properly implemented. Event logs were properly maintained and used to analyze, track, and address safeguards events. The logs indicated that there have been several breakdowns, involving the control of Safeguards information. This issue has been entered into the licensee's corrective action program. (Section S3)

- The security force members adequately demonstrated that they had the requisite knowledge necessary to effectively implement the duties and responsibilities of their positions. Security force personnel were being trained in accordance with the requirements of the Training and Qualification Plan. Weaknesses in the documentation of training were identified. These weaknesses have been entered into the licensee's corrective action program. (Sections S4, S5)

- Management support was adequate to ensure effective implementation of the security program, as evidenced by adequate staffing levels and the allocation of resources to support programmatic needs. (Section S6)

- Security Program audits were comprehensive in scope and depth, the audit findings were reported to the appropriate level of management, and the program was being properly administered. In addition, a review of the documentation applicable to the self-assessment program indicated that the program was being effectively implemented to identify and resolve potential weaknesses. (Section S7)

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Report Details

Summary of Unit 2 Status

Unit 2 entered the inspection period in Operational Mode 1, power operation, with the plant at 100 percent power. Operators reduced power to about 92 percent for cleaning of the "B" circulating water bay from November 29 through December 11, 1999. After that work was complete, the plant remained at a reduced power level, 95 percent power, to provide additional margin to reactor trip setpoints while the Channel "D" reactor protection system trips for thermal margin/low pressure, high power, and local power density were inoperable and in the tripped condition due to the failure of a Channel "D" hot leg resistance temperature detector on December 1, 1999. On December 18, 1999, the plant returned to full power after Channel "D" of the reactor protection system was restored to an operable status. At the conclusion of the inspection period, the plant remained in operation at 100 percent power.

U2.I Operations

U2 O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspector conducted frequent reviews of ongoing plant operations, including observations of operator evolutions in the control room; walkdowns of the main control boards; tours of the Unit 2 radiologically controlled area and other buildings housing safety-related equipment; and observations of several management planning meetings.

The inspector observed procedural adherence and conformance with technical specification requirements during routine operation at power. In general, the inspectors continued to note thorough turnovers and good communication practices among operators in the control room. However, the inspectors noted that the control operators had allowed plant power levels to exceed operational limits on several occasions. This issue is described in Section O8.1 of this report.

U2 O8 Miscellaneous Operations Issues (92700)

O8.1 (Closed) LER 50-336/99-011-00; Exceeding the Thermal Reactor Power Limit

The inspector performed an on-site review of Licensee Event Report (LER) 50-336/99-011-00 which involved five instances where the eight-hour average reactor thermal power based on secondary calorimetric data exceeded the licensed limit of 2700 megawatts. In all instances, the highest average power level was less than 0.2 megawatts thermal above the licensed limit. The licensee documented the events in Condition Reports M2-99-2312 and M2-99-2421. The LER states that the cause of the events was a lack of conservatism in the procedures and alarm setpoints used to limit reactor power. As corrective actions, operating procedures were changed to specify controlling reactor power below 2699.8 megawatts and alarm setpoints were changed to allow a timely response by operators prior to exceeding the limit. The licensee's corrective actions were found acceptable. Because the licensed thermal power limit was

exceeded by a small amount, the safety significance is considered minimal. Therefore, this failure constitutes a violation of minor significance and is not subject to formal enforcement action. LER 50-336/99-011-00 is **closed**.

U2.II Maintenance

U2 M1 Conduct of Maintenance

M1.1 General Maintenance Observations

a. Inspection Scope (62707/61726)

During routine plant inspection tours, the inspectors observed, on a random sampling basis, maintenance and surveillance activities to evaluate the propriety of the activities and the functionality of systems and components with respect to technical specifications and other requirements.

b. Observations and Findings

The inspectors reviewed maintenance work orders and surveillance procedures and interviewed licensee field personnel to verify the adequacy of work controls and surveillance testing. The inspector observed a portion of activities performed under the following automated work orders (AWOs) and surveillance procedures:

• AWO M2-99-03609	Valve 2-CS-16.1B Electrical Breaker Preventive Maintenance
• AWO M2-99-04703	Valve 2-CS-16.1B Motor Operated Valve Preventive Maintenance
• AWO M2-99-03524	"C" RBCCW Heat Exchanger Preventive Maintenance
• Procedure SP 2401D	RPS Trip Matrix Logic and Trip Path Relay Test
• Procedure SP 2601-D2	Power Range Safety Channel and Delta T Calibration

The inspector found that maintenance work was being performed in accordance with approved work orders present at the work site. Overall, the conduct of the maintenance and surveillance activities was found acceptable. However, one concern was noted involving obtaining of necessary approvals for higher risk work activities.

On December 29, 1999, the licensee isolated valve 2-CS-16.1B, a containment sump recirculation isolation valve, to perform preventive maintenance activities. At the time, the "C" RBCCW heat exchanger was also removed from service for cleaning. As specified in procedure MP-20-WM-FAP02.1, "Conduct of On-Line Maintenance," prior to removing the equipment from service, the licensee performed a risk assessment to evaluate the maintenance activities being performed simultaneously. The licensee determined that the maintenance activities placed them in an "Orange" risk condition.

Procedure MP-20-WM-FAP02.1 states that an "Orange" designation signifies a condition where the combination of equipment unavailable represents a higher risk.

The inspector found that the licensee had appropriately evaluated the maintenance activities for risk and that plant management, as well as control room personnel, were aware that this maintenance placed them in an "Orange" condition. The inspector observed briefings of maintenance and operations personnel that reinforced the desire to expedite the performance of maintenance on valve 2-CS-16.1B to minimize the time the plant was in the "Orange" condition. The inspector found the licensee's performance was good in recognizing the "Orange" condition and expediting maintenance activities.

The inspector identified a concern regarding procedure MP-20-WM-FAP02.1, Attachment 1, "Definitions," which stated that Operations Manager approval is required for all planned "Orange" condition evolutions. Discussions with licensee management indicated they were unaware of the statement and therefore, the plant staff had not been documenting Operations Manager approval. The inspector determined that this was not a violation because the Operations Manager was aware of "Orange" condition activities, so, therefore, he had been approving such conditions. The licensee documented the inspector's concern in Condition Report M2-00-0017, and changed procedure MP-20-WM-FAP02.1 to remove the statement regarding Operations Manager approval. The basis for removing the statement was they considered the Probabilistic Risk Assessment group to be the approval authority for what risk conditions are acceptable. The inspector found the licensee's corrective actions acceptable.

c. Conclusions

Overall, the conduct of the maintenance and surveillance activities was found acceptable. However, the NRC identified that although the on-line maintenance procedure specified that Operations Manager approval was needed when the planned removal of equipment from service placed them in an "Orange" risk condition, the plant staff had not been documenting his approval. Because the Operations Manager was aware of the "Orange" conditions, he had approved the conditions. Therefore, no violation occurred. The licensee's corrective action, which involved changing the on-line maintenance procedure to remove the statement regarding Operations Manager approval, was found acceptable.

M1.2 Maintenance Rule Functional Failures

a. Inspection Scope

The inspectors reviewed the licensee's method of identifying Maintenance Rule Functional Failures (MRFFs) as part of the implementation of the Maintenance Rule (10 CFR 50.65) with respect to the equipment issues described in the following condition reports (CRs).

CR M2-99-1664 (Dated 5/18/99) The setpoint for "A" Channel Thermal Margin/Low Pressure (TM/LP) is intermittently failing.

CR	M2-99-1765	(Dated 5/28/99) Channel "D" TM/LP setpoint was identified to be lower than expected. While performing a calibration, found coefficient out of specification due to dirty flow dependent setpoint selector switch (FDSSS).
CR	M2-99-2764	(Dated 10/25/99) The FDSSS was found to have dirty connections. Cycling the FDSSS causes all indications to return their normal values.
CR	M2-99-2994	(Dated 11/19/99) While monitoring key parameters, the "A" TM/LP setpoint was noted to be significantly lower than the other three channels.
CR	M2-99-3006	(Dated 11/19/99) TM/LP setpoint failed low due to connections through the FDSSS. This is a reoccurring problem. It was discovered that the TM/LP CPD-1-B/50 potentiometer was not making clean connection through the FDSSS.

b. Observations and Findings

The inspectors found that the above noted CRs described five failures of a the TM/LP potentiometer which resulted in a non-conservative movement of the TM/LP setpoint for the reactor protection system (RPS) for Unit 2. The failures were due to the contacts not making a clean connection through the FDSSS. As can be seen by the above noted CRs, the RPS had a recurring problem with the FDSSS oxidizing and giving erroneous setpoint indication. The maintenance activity to correct this condition was to cycle the FDSSS (i.e., clean the switch by cycling) which caused all indications to return their normal values. This failed condition was originally discovered on May 18, 1999, (CR M2-99-1664) and recurred on May 28, 1999 (CR M2-99-1765). The inspectors reviewed the details of these functional failures and the licensee's corrective actions and determined that no operability issues existed regarding these failures since individual channel operability was restored within the technical specification required action times. However, the inspectors questioned why the occurrence on May 28, 1999, (CR M2-99-1765) had not been considered as the repetitive maintenance rule functional failure that caused the performance measures for the RPS system to be exceeded.

The licensee issued CR M2-99-3226 to review this condition for the purpose of evaluating the need for additional corrective action. Engineering Department Instruction (EDI) 30710, Rev. 1, "Maintenance Rule Functional Failures ," requires that both instrument drift two times the acceptable level and failure of one channel of the instrument, no matter how many redundant channels there are, be identified as an MRFF. Also, EDI 30730, "Maintenance Rule Goal Setting and Monitoring," requires considerations of goal setting and movement into an (a)(1) category for repetitive functional failures. At the time of this inspection, this determination had not been accomplished by the licensee.

Paragraph (a)(1) of 10 CFR 50.65, Maintenance Rule, requires that when the performance or condition of a structure, system, or component does not meet established goals, appropriate corrective action shall be taken. As stated above, the licensee failed to recognize, until after being identified by the inspectors, that the

established performance measures of no repetitive functional failures for the Unit 2 RPS was exceeded on May 28, 1999, and again exceeded in October and November 1999, when another three functional failures occurred. The licensee failed to place the system into an (a)(1) status and establish goals commensurate with safety in violation of 10 CFR 50.65(a)(1). This violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as CR M2-99-3226.

c. Conclusion

The licensee failed to recognize that the established performance measures of no repetitive functional failures for the Unit 2 RPS was exceeded on May 28, 1999, and again exceeded in October and November 1999, when another three functional failures occurred. The licensee failed to place the system into an (a)(1) status and establish goals commensurate with safety in violation of 10 CFR 50.65(a)(1). This violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy. **(NCV 50-336/99-14-01)**

M1.3 Troubleshooting of Reactor Protection System Problems

a. Inspection Scope (62707/37551)

The inspector evaluated various problems that have affected the reactor protection system (RPS) during the inspection period and reviewed the actions taken to address these problems. The inspector also observed portions of work activities and reviewed the documentation associated with Automated Work Orders (AWOs) M2-99-13193 and M2-99-12774, which involved troubleshooting of local power density pre-trip alarms on RPS Channel "D" and troubleshooting and repair of the Channel "A" linear range nuclear instrument drawer, respectively. The inspector discussed the troubleshooting activities and overall system performance with instrumentation and control technicians and the responsible system engineer.

b. Observations and Findings

The Unit 2 RPS has been subject to both isolated and chronic problems that have affected system operation. The inspector reviewed the following isolated problems and the corrective actions implemented to address them:

1. The reactor coolant system loop 1 hot leg resistance temperature detector input to RPS Channel "D" began spiking on December 1, 1999. The spiking induced Channel "D" reactor trip signals for local power density, high power, and thermal margin/low pressure. The operators declared the affected trip signals inoperable and executed the actions required by technical specifications. The affected trip signals were restored to an operable status by implementing Temporary Modification 2-99-031 to substitute the reactor coolant system loop 2 hot leg resistance temperature detector input to RPS Channel "D" for the defective input. With both hot leg temperature inputs to RPS Channel "D" from loop 2, this

channel would respond more slowly to certain asymmetric events requiring RPS actuation (e.g., a large main steam line break upstream of the non-return valve). However, the licensee demonstrated that through diverse trip signals within the channel and a reduction in the unrodded radial flux peaking factor limit, the safety margin would not be reduced for these events. The inspector found that the temporary modification had an adequate technical basis and was acceptable.

2. Operators observed linear range nuclear instrument power swings on Channel "A" while plant power was stable. This problem was effectively repaired under AWO M2-99-12774 by replacement of two circuit modules in the linear range power drawer on November 4, 1999. Due to difficulties in obtaining replacement parts, Channel "A" was unavailable for 46 hours.

The inspector also reviewed the following chronic problems and the licensee's plans to address these problems:

1. Infrequent, but recurring non-conservative changes in the thermal margin/low pressure trip setpoint, particularly the Channel "A" setpoint, have occurred due to increased resistance in the flow dependent setpoint selector switch for individual channels. As a preventive measure, the licensee has been cycling the flow selector switch monthly to prevent the increased resistance at the switch contacts that causes a non-conservative change in the thermal margin/low pressure trip setpoint. However, as described in Section U2 M1.2 of this report, this maintenance activity has been ineffective. Because the switch has no needed function, the licensee plans to remove this switch from the circuit to correct the problem. The licensee is evaluating this modification for implementation prior to the next refueling outage.

2. Frequent local power density pre-trip alarms have occurred, particularly on Channel "D." After extensive troubleshooting under AWO M2-99-13193, the licensee determined that the frequent local power density pre-trips result from actual plant conditions and a small operating window within the pre-trip setpoint boundary rather than from a problem with the RPS sensors or instrumentation. The licensee plans to broaden the operating range by changing the pre-trip setpoints. This modification is currently scheduled for January 2000.

3. Input signal noise has caused RPS response, including one instance where noise was manifested as a turbine trip signal on Channel "B." To address signal noise problems, the licensee plans to replace wiring subject to signal noise generation with shielded wiring during the next refueling outage, which is scheduled to begin in April 2000.

4. System obsolescence has resulted in spare parts procurement difficulties. Difficulty in obtaining satisfactory replacement parts has contributed to longer than necessary unavailability of the affected RPS channel. The licensee plans to address system obsolescence by replacing the RPS. The licensee has

scheduled replacement of the nuclear instrumentation portion prior to the next refueling outage.

The inspector evaluated the effect of the above issues with respect to RPS operability. The inspector considered the isolated failures of the Channel "A" linear range nuclear instrument drawer and the Channel "D" loop 1 hot leg resistance temperature instrument as events representative of expected random component failures. The licensee complied with technical specification requirements when the affected channels were inoperable and implemented appropriate corrective maintenance to restore the channels to operable status. The frequent local power density pre-trip alarms represent an operator distraction rather than a functional problem with the RPS. The licensee has assigned an appropriate priority to the elimination of this distraction, as indicated by scheduled modification in January 2000, and the plant operators have maintained plant power level at about 99.3 percent to reduce the frequency of the distracting alarms. Similarly, the signal noise generation and system obsolescence represent a slight increased potential for an inadvertent reactor trip rather than a threat to the reliability of the system in performing its safety function.

The inspector found the infrequent, non-conservative changes in the thermal margin/low pressure trip setpoint somewhat more significant in that a recurring condition was rendering a trip channel inoperable. The thermal margin/low pressure setpoint is the higher of a calculated value, which is provided by the core protection calculator based on reactor power and core power distribution, and a floor value, which is approximately equal to the technical specification minimum value for the nominal core power distribution at full power. On five instances during the period from May to November 1999, including four instances affecting RPS Channel "A," the thermal margin/low pressure setpoint for one channel decreased to the floor value, which was slightly below the technical specification minimum setpoint for the core power distribution existing at the time. The licensee complied with technical specification requirements during each instance by declaring the trip channel inoperable, placing the affected channel in the bypassed condition until the channel was restored to an operable status, and restoring the channel to operable status within the 48 hour allowed outage time. Although the inspector found that maintenance activities to clean the flow dependent setpoint selector switch returned the affected channel to operable status, the recurrent nature of the problem, despite preventive maintenance activities, indicated that the RPS was in a degraded state.

As late as November 1999, the licensee planned to continue with preventive maintenance activities and repair the switch after the next refueling outage. The inspector was concerned that these actions were not timely based on the potential for multiple channels to be affected by the non-conservative change in the thermal margin/low pressure setpoint. The inspector discussed this concern with the licensee's engineering management. As an interim corrective action, the licensee established a computer alarm to promptly alert operators when the thermal margin/low pressure setpoint drifts downward from its normal value at full power. This alarm supplements the permanent control board alarm that annunciates when the setpoint reaches the floor value. In addition, the licensee realigned engineering resources to support a schedule to

remove the flow dependent setpoint selector switches from each channel of the RPS prior to the next refueling outage, which begins in April 2000. Although the licensee's actions were untimely, the inspector found that this interim corrective action is adequate to address operability concerns until the planned modification is implemented because the computer alarm provides prompt notification to the operators of setpoint drifts.

c. Conclusions

The NRC concluded that the licensee's determination of continued operability of the Unit 2 RPS, despite some degradation, was adequately founded. The majority of issues pose only a minimal increase in the probability of an inadvertent reactor trip or a distraction to the control operators and have no effect on the system's safety function. The licensee has implemented or scheduled appropriate measures to address the degraded conditions consistent with their importance to safety. However, the licensee was untimely in developing a plan to address recurrent instances where an RPS channel was rendered inoperable due to a drifting thermal margin/low pressure setpoint. This untimeliness relates to a violation described in Section U2 M1.2, where the NRC found that the licensee failed to identify that system performance goals with respect to maintenance preventable functional failures, which were established by the licensee pursuant to 10 CFR 50.65, had not been met.

U2 M8 Miscellaneous Maintenance Issues

M8.1 (Closed) IFI 50-336/98-02-01; Implementation of Two Maintenance Rule Issues: (1) System Engineer Determination of Maintenance Rule Functional Failures and (2) Licensee's Action to Clarify Definitions of Functional Boundaries Between Interfacing and Overlapping Systems

a. Inspection Scope (92902)

The inspectors reviewed the licensee's response and related actions to address Inspector Follow-up Item (IFI) 50-336/98-02-01. This IFI was opened to review two (2) specific items after the unit had been operating for a period of time to allow gathering real plant data related to system performance. One of the items dealt with licensee's action to clarify definitions of functional boundaries between interfacing and overlapping systems. The second item dealt with System Engineer determination of maintenance rule functional failures (MRFFs) following plant restart. Examples included failures associated with the control room air conditioning (CRAC) exhaust fans and safety injection tanks (SIT) system.

The inspectors conducted in-office and onsite reviews of the IFI. This review included a review of Unit 2 engineering and maintenance rule procedures, associated engineering evaluations/memorandums, work activities, and corrective action documents in the licensee's corrective action process. In addition, these items were discussed with operations personal and system engineers.

b. Observations and Findings

The item concerning physical boundaries for functions that relied on components in multiple systems that were not clearly defined for performance monitoring is closed based on the scheduled completion of corrective actions outlined in CR 98019252. All actions are scheduled to be completed by March 2000 including all related training for system engineers and operators and an issue identified by the inspectors related to cascading unavailability times. When a structure, system, or component (SSC) becomes unavailable, the associated support systems would also be considered unavailable based on the functions provided and the methods used by the probabilistic risk assessment (PRA) staff to establish performance criteria. Based on discussions with the licensee's PRA staff, the tracking of unavailability for both the primary and support SSCs is essential since the PRA staff established maintenance rule performance criteria (unavailability times) using the cascading concept.

The item on System Engineers correctly determining MRFFs for two specific SSCs is closed. The inspectors reviewed and determined that the functional failures associated with the control room air conditioning (CRAC) exhaust fans and safety injection tanks (SIT) system were appropriately handled by the licensee based on a review of the following: Condition Reports (CRs) M2-96-0196 and M2-98-1190, Automated Work Orders (AWOs) M2-98-03317 and M2-98-03462, level transmitter LT 311 on the SIT (CR M2-98-1105), maintenance rule expert panel meeting minutes dated August 7, 1998; and Adverse Condition Reports (ACRs) 04066, 03529, 04775, 04794, 04260, and 06732.

c. Conclusion

The licensee made acceptable maintenance rule functional failure determinations and instituted appropriate corrective actions to address the failures on the CRAC exhaust fans and SIT system. The item on physical boundaries on SSC functions will be closed based on the licensee tracking completion of all corrective actions associated with CR 98019252 which is scheduled for completion in March 2000. IFI 50-336/98-02-01 is **closed**.

M8.2 (Closed) IFI 50-336/98-02-02; Implementation of Four Maintenance Rule Issues: (1) Review Effectiveness of Licensee's Maintenance and Performance Monitoring; (2) Balancing Reliability and Unavailability and (3)&(4) Review Operators Knowledge and Use of On-Line Maintenance Risk Assessment

a. Inspection Scope (92902)

The inspectors reviewed the licensee's response and related actions to address Inspector Follow-up Item (IFI) 50-336/98-02-02. This IFI was opened to review four (4) specific items after the unit had been operating for a period of time to allow gathering real plant data related to performance. The first item dealt with the licensee's ability to assess the effectiveness of maintenance and performance monitoring. The second item dealt with balancing reliability and unavailability. The third and fourth items dealt with

reviewing operators knowledge of on-line maintenance risk assessment and the operators use of on-line maintenance risk assessment.

The inspectors conducted in-office and onsite reviews of the IFI. This review included a review of Unit 2 engineering, operations, work control and maintenance rule procedures, associated engineering evaluations/memorandums, work activities, and corrective actions documents in the licensee's corrective action process. In addition, the items were discussed with operations personal and system engineers.

b. Observations and Findings

The item on the effectiveness of the licensee's maintenance and performance monitoring programs is closed based on a sample review of system performance and monitoring on various systems and based on a review of the licensee's Periodic Assessment of the Maintenance Rule for Units 2 & 3, dated December 17, 1999. The performance criteria established for many high risk significant systems in Unit 3 was found to be in question and will be tracked by the completion of licensee's corrective action for Condition Report M3-99-3966 and Unresolved Item 50-423/99-14-01.

The item on balancing reliability and unavailability is closed based on a review of the completed periodic assessments in May 1998 and the "Periodic Assessment of the Maintenance Rule Program" report for Units 2 & 3, dated December 17, 1999, which appropriately addressed balancing reliability and unavailability as defined in 10 CFR 50.65 (a)(3). Balancing reliability and unavailability program requirements were described in Attachment 1 to Engineering Department Instructions (EDI) No. 30740, "Maintenance Rule Periodic Assessment". Several items remained open from the Units 2 & 3 past periodic assessments completed in May 1998, and are being tracked under CRs identified in Attachment 8-1 of the recently completed periodic assessment dated December 17, 1999.

The item on reviewing operators knowledge of on-line maintenance risk assessment is closed based on the licensee's appropriate development and implementation of their on-line and shutdown safety assessment program as outlined in the licensee's procedures "Conduct of On-Line Maintenance," MP-20-WM-FAP02.1 and "On-Line Maintenance, MP-20-WM-SAP02". Based on a review of lesson plan material and interviews with licensed reactor and senior reactor operators, the inspectors determined that the operators had received training and were knowledgeable on various aspects of the maintenance rule including on-line maintenance risk assessment.

The item on reviewing operators use of on-line maintenance risk assessment following plant return to on-line is closed. The inspectors reviewed a sample of on-line corrective maintenance emergent work activities performed over the last several months and concluded that risk had been appropriately considered in the performance of this work.

c. Conclusion

The licensee made acceptable determinations and instituted appropriate corrective actions to address the four (4) items: review the effectiveness of the licensee's maintenance and performance monitoring; balancing reliability and unavailability; operators knowledge and use of on-line maintenance risk assessment. IFI 50-336/98-02-02 is **closed**.

M8.3 (Closed) LER 50-336/98-20-00; Safety Injection Recirculation Header Inservice Visual Inspection Requirements

a. Inspection Scope (37550, 92700, 92903)

The inspector conducted an on-site review of Licensee Event Report (LER) 50-336/98-20-00, Unit 2 technical specifications (TS), associated corrective actions documented in the licensee's corrective action process, the Unit 2 Final Safety Analysis Report (FSAR), supporting codes and standards, and a selection of testing documentation.

b. Findings and Observations

On September 29, 1998, while Unit 2 was defueled, the licensee identified that certain portions of the safety injection (SI) recirculation header piping had historically not been visually tested, in accordance with American Society of Mechanical Engineers (ASME) Code, Section XI, Article IWV-5000, "Visual Testing" (VT). The code testing was required by Unit 2, TS 4.0.5.

The licensee's corrective actions included procedure updates, drawing changes, verification of SI recirculation header flow testing data and the adequate performance of selected visual tests. Failing to establish and implement adequate testing to ensure that the requirements of ASME Section IX were met, is a violation of Unit 2, TS 4.0.5. This Severity Level IV violation is being treated as a Non-Cited Violation consistent with Section VII.B.1.a of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on the issue being entered into the licensee's corrective action program. This issue was entered as Condition Report M2-98-2601. The inspector determined that the risk informed, safety significance of this issue was low and the licensee's corrective actions were adequate.

c. Conclusions

The licensee identified in 1998 that Unit 2 TS required, ASME code visual tests, had not been performed on portions of SI recirculation header piping. This is a violation of Unit 2 TS 4.0.5. The licensee's corrective actions were found acceptable. This violation of TS 4.0.5, is being treated as a **Non-Cited Violation (NCV 50-336/99-14-02)**. LER 50-336/98-20-00 is **closed**.

M8.4 (Closed) LER 50-336/98-23-00; Containment Air Recirculation Fan Testing

a. Inspection Scope (37550, 92700, 92903)

The inspector conducted an on-site review of Licensee Event Report (LER) 50-336/98-23-00, Unit 2 technical specifications (TS), associated corrective actions documented in the licensee's corrective action process, the Unit 2 Final Safety Analysis Report (FSAR), supporting codes and standards, and a selection of testing documentation.

b. Findings and Observations

On September 24, 1998, while Unit 2 was defueled, the licensee identified that the low speed portions of containment air recirculation (CAR) fan testing did not meet the requirements of Unit 2 technical specification (TS) surveillance requirement (SR) 4.6.2.1.2 (a). The TS SR requires that the CAR fans be started in slow speed once every 31 days when the unit is in Modes 1 through 3. Although historically, the CAR fans were tested once every 31 days, the tests did not include starting each of the four CAR fans from a stopped, de-energized condition.

The licensee's corrective actions included procedure changes, verification of historical CAR fan starting circuitry test data and the adequate testing of each of the CAR fans. Failing to establish and implement adequate CAR fan testing is a violation of Unit 2, TS 4.6.2.1.2. This Severity Level IV violation is being treated as a Non-Cited Violation consistent with Section VII.B.1.a of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on the issue being entered into the licensee's corrective action program. This issue was entered as Condition Report M2-98-2894. The inspector determined that the risk informed, safety significance of this issue was low and the licensee's corrective actions were adequate.

c. Conclusions

The licensee identified in 1998 that Unit 2 TS required, CAR fan start testing, had historically not been performed. This is a violation of Unit 2 TS 4.6.2.1.2. The licensee's corrective actions were found acceptable. This violation of TS 4.6.2.1.2, is being treated as a **Non-Cited Violation (NCV 50-336/99-14-03)**. LER 50-336/98-23-00 is **closed**.

M8.5 (Closed) LER 50-336/98-25-00; Check Valve Testing Requirements

a. Inspection Scope (37550, 92700, 92903)

The inspector conducted an on-site review of Licensee Event Report (LER) 50-336/98-25-00, Unit 2 technical specifications (TS), associated corrective actions documented in the licensee's corrective action process, the Unit 2 Final Safety Analysis Report (FSAR), supporting codes and standards, and a selection of testing documentation.

b. Findings and Observations

On November 11, 1998, while Unit 2 was defueled, the licensee identified that certain check valves had historically not been tested at design maximum flow conditions, in accordance with American Society of Mechanical Engineers (ASME) Code, Section XI, "Inservice Testing". The ASME Code testing is required by Unit 2 TS 4.0.5.

The licensee's corrective actions included procedure updates, verification of historical performance, flow and position indication testing data, and the adequate performance of selected full flow tests. No adverse conditions were identified. Failing to establish and implement adequate testing to ensure that the requirements of ASME Section IX were met is a violation of TS 4.0.5. This Severity Level IV violation is being treated as a Non-Cited Violation consistent with Section VII.B.1.a of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on the issue being entered into the licensee's corrective action program. This issue was entered as Condition Report M2-98-3396. The inspector determined that the risk informed, safety significance of this issue was low and the licensee's corrective actions were adequate.

c. Conclusions

The licensee identified in 1998 that TS required check valve full flow tests had not been performed in accordance with ASME Section XI requirements, on specific check valves. This is a violation of TS 4.0.5. The licensee's corrective actions were found acceptable. This violation of TS 4.0.5, is being treated as a **Non-Cited Violation (NCV 50-336/99-14-04)**. LER 50-336/98-25-00 is **closed**.

U2.III Engineering

U2 E1 Conduct of Engineering

E1.1 Year 2000 Project Readiness Review

a. Inspection Scope (71750)

The inspector reviewed the licensee's contingency plan for the Year 2000 (Y2K) rollover and observed implementation of the plan from December 31, 1999, into January 1, 2000.

b. Observations and Findings

The licensee's contingency plans provided the staffing, organization, and mitigation strategies to address unexpected, but possible Y2K related issues. The staffing plan provided for additional personnel in all areas essential for operations, with an emphasis on instrumentation and information technology specialists.

On December 31, 1999, the inspector observed that the licensee had staffed its Y2K contingency organization. Throughout the rollover period, the licensee monitored a variety of information sources for indications of potential significant Y2K related issues.

The additional personnel were used to monitor computers and other components with embedded digital devices during critical transition periods. No significant problems were identified.

c. Conclusions

The licensee developed and implemented contingency plans to address potential Y2K related issues at Millstone Units 2 and 3. No significant problems developed during the Y2K rollover period.

U2 E8 Miscellaneous Engineering Issues

E8.1 (Closed) LER 50-336/98-16-00; Safety Injection System Administrative Controls

The inspector conducted an on-site review of Licensee Event Report (LER) 50-336/98-16-00, which addresses certain postulated post loss of coolant accident (LOCA) conditions in which the operability and design basis of the safety injection tanks (SIT) could be affected. The postulated conditions are related to the administrative controls applied to a normally locked closed safety injection (SI) system manual isolation valve connected to the SIT recirculation branch line. The inspector reviewed the LER, Unit 2 technical specifications (TS), associated corrective actions documented in the licensee's corrective action process, the Unit 2 Final Safety Analysis Report (FSAR), supporting codes and standards, and a selection of plant modification documentation.

The postulated conditions resulted from the licensee's corrective actions for a number of NRC violations involving the Unit 2 design basis. Failing to adequately establish and implement design controls to ensure that the SI system design criteria were correctly translated into specifications, drawings and procedures, is a violation of 10 CFR 50, Appendix B, Criterion III, Design Control. Because, the condition was postulated, reported and corrected by the licensee as part of its response to previous NRC violations, the condition is considered to be dispositioned from an enforcement perspective. This issue was entered into the licensee's corrective action program as Condition Reports M2-98-1704. The inspector determined that the risk informed, safety significance of this issue was low and the licensee's corrective actions were adequate. LER 50-336/98-16-00 is **closed**.

E8.2 (Closed) LER 50-336/98-18-00 & 01; Spacial Separation of Redundant Cables

a. Inspection Scope (37550, 92700, 92903)

The inspector conducted an on-site review of Licensee Event Report (LER) 50-336/98-18-00 & 01, Unit 2 technical specifications (TS), associated corrective actions documented in the licensee's corrective action process, the Unit 2 Final Safety Analysis Report (FSAR), supporting codes and standards, and a selection of plant modification documentation.

b. Findings and Observations

On December 18, 1998, while Unit 2 was defueled, the licensee identified that certain safety-related cable trays did not meet Institute of Electrical and Electronic Engineers (IEEE) standards 279-1971 and 308-1971. The IEEE standards were incorporated into the Unit 2 design basis by Unit 2 FSAR, Section 8.7.

The licensee's corrective actions included procedure updates, drawing changes, mechanical modifications, verification of safety-related cable tray and cable placements through system walkdowns, and ongoing long term generic reviews. Failing to adequately establish and implement design controls to ensure that safety related cable tray spacing and placement design bases were correctly translated into specifications, drawings and procedures, is a violation of 10 CFR 50, Appendix B, Criterion III, Design Control. This Severity Level IV violation is being treated as a Non-Cited Violation consistent with Section VII.B.1.a of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on the issue being entered into the licensee's corrective action program. This issue was entered as Condition Report M2-98-2401. The inspector determined that the risk informed, safety significance of this issue was low and the licensee's corrective actions were adequate.

c. Conclusions

The licensee identified in 1998 that certain Unit 2 safety-related cable trays and cables did not meet design basis requirements for separation and/or placement. The licensee's corrective actions were found acceptable. This violation of 10 CFR 50, Appendix B, Criterion III, Design Control, is being treated as a **Non-Cited Violation (NCV 50-336/99-14-05)**. LER 50-336/98-18-00 & 01 are **closed**.

E8.3 (Closed) LER 50-336/98-19-00; Auxiliary Feedwater Regulating Valve Response to a High Energy Line Break

The inspector conducted an on-site review of Licensee Event Report (LER) 50-336/98-19-00, which addresses certain auxiliary feedwater (AFW) system non-safety related components that had been credited with mitigating the consequences of a design basis high energy line break (HELB). The inspector reviewed the LER, Unit 2 technical specifications (TS), associated corrective actions documented in the licensee's corrective action process, the Unit 2 Final Safety Analysis Report (FSAR), supporting codes and standards, and a selection of plant modification documentation.

As part of its corrective actions for NRC Non-Cited Violation 50-336/98-202-02 and a number of related NRC violations involving the Unit 2 design basis, the licensee implemented extensive reviews of the Unit 2 design basis. The licensee's corrective actions for the specific conditions identified in LER 50-336/98-26-00 included procedure updates, drawing changes, mechanical modifications, verification of historical performance and test data, and revised post-HELB engineering calculations. Failing to adequately establish and implement design controls to ensure that the AFW system design criteria were correctly translated into specifications, drawings and procedures, is

a violation of 10 CFR 50, Appendix B, Criterion III, Design Control. Because, the condition was identified, reported and corrected by the licensee as part of its response to a previous NRC violation, the condition is considered to be dispositioned from an enforcement perspective. This issue was entered into the licensee's corrective action program as Condition Reports M2-98-2503, 2826 and 2780. The inspector determined that the risk informed, safety significance of this issue was low and the licensee's corrective actions were adequate. LER 50-336/98-19-00 is **closed**.

E8.4 (Closed) LER 50-336/98-24-00; Potential Containment Leakage Path

a. Inspection Scope (37550, 92700, 92903)

The inspector conducted an on-site review of Licensee Event Report (LER) 50-336/98-24-00, Unit 2 technical specifications (TS), associated corrective actions documented in the licensee's corrective action process, the Unit 2 Final Safety Analysis Report (FSAR), supporting codes and standards, and a selection of plant modification documentation.

b. Findings and Observations

On October 30, 1998, while Unit 2 was defueled, the licensee identified that certain model 11 Foxboro containment pressure instruments did not meet FSAR, Section 5.2.8.2.1, design basis requirements for post loss of coolant accident (LOCA) pressure retention.

The licensee's corrective actions included drawing changes, instrument replacements, and verification of the installed containment pressure instrumentation configuration. Failing to adequately establish and implement design controls to ensure that the safety-related design bases for containment pressure instruments were correctly translated into specifications, drawings and procedures, is a violation of 10 CFR 50, Appendix B, Criterion III, Design Control. This Severity Level IV violation is being treated as a Non-Cited Violation consistent with Section VII.B.1.a of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on the issue being entered into the licensee's corrective action program. This issue was entered as Condition Report M2-98-3267. The inspector determined that the risk informed, safety significance of this issue was low and the licensee's corrective actions were adequate.

c. Conclusions

The licensee identified in 1998 that certain Unit 2 containment pressure instruments did not meet FSAR design basis requirements for post-LOCA pressure retention. The licensee's corrective actions were found acceptable. This violation of 10 CFR 50, Appendix B, Criterion III, Design Control, is being treated as a **Non-Cited Violation (NCV 50-336/99-14-06)**. LER 50-336/98-24-00 is **closed**.

E8.5 (Closed) LER 50-336/98-26-00; Pressurizer Spray Line Fatigue Limits

a. Inspection Scope (37550, 92700, 92903)

The inspector conducted an on-site review of Licensee Event Report (LER) 50-336/98-26-00, Unit 2 technical specifications (TS), associated corrective actions documented in the licensee's corrective action process, the Unit 2 Final Safety Analysis Report (FSAR), supporting codes and standards, and a selection of plant modification documentation.

b. Findings and Observations

On December 23, 1998, while Unit 2 was defueled, the licensee identified that historically, pressurizer spray line operating procedures and practices did not meet the design basis established in the FSAR for reheating, maximum spray flow and other parameters affecting thermal fatigue parameters for the pressurizer spray line. The Unit 2 FSAR incorporated American Society of Mechanical Engineers (ASME) Code, Section III, fatigue and thermal cycling criterion into the Unit 2 design basis. The licensee's corrective actions included procedure updates; drawing changes; mechanical modifications; engineering analysis of historical performance, temperature and flow data; and ongoing long term generic reviews of other safety related systems. No adverse physical conditions were identified. Failing to adequately establish and implement design controls to ensure that the pressurizer spray line design criteria were correctly translated into specifications, drawings and procedures, is a violation of 10 CFR 50, Appendix B, Criterion III, Design Control. This Severity Level IV violation is being treated as a Non-Cited Violation consistent with Section VII.B.1.a of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on the issue being entered into the licensee's corrective action program. This issue was entered as Condition Report M2-98-3839. The inspector determined that the risk informed, safety significance of this issue was low and the licensee's corrective actions were adequate.

c. Conclusions

The licensee identified in 1998 that pressurizer spray line operating procedures and practices did not meet the design basis established in the FSAR for reheating, maximum spray flow and other parameters affecting thermal fatigue parameters for the pressurizer spray line. The licensee's corrective actions were found acceptable. This violation of 10 CFR 50, Appendix B, Criterion III, Design Control is being treated as a **Non-Cited Violation (NCV 50-336/99-14-07)**. LER 50-336/98-26-00 is **closed**.

E8.6 (Closed) URI 50-336/98-206-02; Safety Parameter Display System

a. Inspection Scope (92903)

The inspector performed an on-site inspection of the licensee's actions to address Unresolved Item (URI) 50-336/98-206-02. The evaluation included a review of the licensee's documents to close the issue, additional applicable documentation, as needed, and interviews of responsible engineering and supervisory personnel.

b. Observations and Findings

URI 50-336/98-206-02 involved two examples where the safety parameter display system (SPDS) did not meet the licensing basis commitments the licensee made in a letter dated October 8, 1986. This letter described how the SPDS satisfied Supplement 1 to NUREG 0737, "Clarification of TMI Action Plan Requirements." The first example involved the following statement: "The SPDS is 'on' at all times during operating Modes 1, 2, and 3. During normal operations, all safety functions are green and are displayed at all times." The URI concerned the fact that the Unit 2 operators had been trained to display SPDS only upon entry into emergency operating procedures. As described in a letter dated December 30, 1999, the licensee addressed this concern by implementing administrative controls to ensure that at least one of the four control room display monitors shows the SPDS overview. In addition, an SPDS modification is currently scheduled before the next refueling outage that installs a dedicated monitor for continuously displaying SPDS in the control room. The inspector found the licensee's corrective actions to be acceptable.

The second example in which the SPDS did not meet licensing basis commitments involved the following statement: "The status of each of the six safety functions for the selected procedure is indicated by one of two colors. The green color indicates that the safety functions are not exceeded. A red color indicates that the limits are exceeded." The URI concerned the fact that the SPDS display had been modified to no longer use the colors (or any other alerting mechanism) to continually indicate the status of the six safety functions. As described in a letter dated March 11, 1999, the licensee addressed this discrepancy by changing the licensing basis using the10 CFR 50.59 process to reflect that the current SPDS display provides the operators with the plant parameters, but relies on operators to evaluate the parameters.

After reviewing the licensee's actions, the inspector was concerned that the current SPDS requires operators to scroll through multiple screens to assess the status of the six critical safety functions. Supplement 1 to NUREG 0737, Section 4.1.a, states that, "The SPDS should provide a concise display of critical plant variables to the control room operators to aid them in rapidly and reliably determining the safety status of the plant." NUREG 1342, "A Status Report Regarding Industry Implementation of Safety Parameter Display Systems," describes that operator decision making can be hampered when displays are widely dispersed because it does not facilitate the comparison of variables or the integration of various symptoms within the same time frame. This induces operators to fixate on a limited set of plant variables and give undue attention to irrelevant plant anomalies while safety functions could be in jeopardy. NUREG 1342 also describes that Supplement 1 to NUREG 0737 can be satisfied by either providing a dedicated, single display of plant variables, or by providing a hierarchy of display "pages" on a single monitor with perceptual cues to alert the user to changes in the safety function status of the plant. NUREG 1342 states that SPDS designs were considered unacceptable when they provided neither a continuous display of variables nor an alerting mechanism, such as the safety function status indicators.

Based on the NRC position provided in NUREG 1342, the inspector discussed his concern that the Millstone Unit 2 SPDS provided neither a continuous display nor an alerting mechanism with licensee management. In a letter dated January 13, 2000, the licensee committed to modify SPDS to provide the green and red safety function status indicators by no later than the end of refueling outage 14. The inspector found the proposed modification to be acceptable in addressing the concern.

c. Conclusions

The licensee's corrective actions were found acceptable in addressing the concerns with SPDS that were discussed in URI 50-336/98-206-02. URI 50-336/98-206-02 is **closed**. No violation of NRC requirements was identified.

Report Details

Summary of Unit 3 Status

Unit 3 began the inspection period on November 23, 1999, operating at 100 percent power. On November 25, operators reduced power to approximately 75%, as requested by ISO New England due to a fire near power lines several miles offsite. During this period, two 345 Kv power lines were available to supply offsite power to Millstone Station. Full power operation was restored later that day. No plant problems were encountered related to the transition from December 31, 1999 to January 1, 2000. Unit 3 continued to operate at 100% through the end of the report period on January 3, 2000.

U3.I Operations

U3 O1 Conduct of Operations

O1.1 Operational Activities and Control Room Observations

a. Inspections Scope (71707)

The inspector conducted frequent tours of the control room, examining the status of plant equipment, reviewing logs, and observing operator shift turnovers and the conduct of specific operational evolutions. The inspector discussed with the licensed operators and shift managers the governing technical specifications (TS) for certain preventive maintenance and surveillance activities and noted entries into the applicable limiting conditions for operation (LCOs). As appropriate, plant inspection-tours were conducted to verify field equipment status consistent with the observed operational controls and to check the affected component tagging.

b. Observations and Findings

The inspector evaluated the licensee's handling of certain operability, reportability, and TS compliance issues, raised as a result of generic NRC communications, inspector observations, or internal licensee reviews required to meet regulatory requirements. Included among these assessment activities were reviews of the following documents and the resultant licensee conclusions:

- Reportability Determination for Condition Report (CR) M3-99-0802, titled "Entry into Technical Specification 3.0.3 due to Both Trains of the Quench Spray System (QSS) Being Rendered Momentarily Inoperable", concluded that one train of the QSS was actually operable, despite the unavailability of supporting ventilation equipment for some period of time. Consequently, the licensee determined that this condition did not involve an entry into TS 3.0.3 and that the condition was not reportable pursuant to 10 CFR 50.73.

- Technical Specification Change Request 3-12-99 was submitted by the licensee to the NRC on November 29, 1999, to address the need for using an updated

standard in the testing of nuclear-grade activated charcoal that is used in safety systems governed by the Unit 3 TS requirements. Since the existing TS provisions specified compliance with the earlier standard, the licensee's regulatory affairs staff issued a memorandum (RA-99-248), dated December 9, 1999, noting the NRC recognition in Generic Letter 99-02 that enforcement discretion may be required to eliminate unnecessary testing. The documented Regulatory Affairs position indicates that not only is enforcement discretion on this matter implicitly provided, but also that compliance with the updated testing standards bounds the existing TS requirements. Thus, licensee commitments and performance in response to Generic Letter 99-02 also meet present Unit 3 license requirements.

- Operating Procedure OP 3304A Section 4.17 discusses the steps and operational provisions for establishing an alternate cooling water injection flow path to the reactor coolant pump (RCP) seals, should such actions be required (e.g., emergency operating procedure direction). When in such an alignment, a question of component operability arises because TS 4.4.6.2.1 surveillance requirements may not be met because of a specified flow modulating valve position. The licensee issued CR M3-99-3954 to document this apparent TS/OP conflict, to determine whether the applicable TS actions are required when the unit is placed in this alternate mode of seal injection, and to evaluate the operational criteria for the reactor coolant system leakage to the RCP seals. The recommended CR corrective actions were appropriately directed to the potential TS compliance concerns.

The inspector also assessed the operational controls that were instituted on December 28, 1999, to compensate for a failed area heater in the auxiliary building. The Unit 3 Technical Requirements Manual specifies that two trains of four heaters are required whenever the outside temperature is less than or equal to 17° F. The inspector confirmed that the ambient outside temperature did not drop to the temperature limit, which would have required declaring the corresponding train of the charging system inoperable and a corresponding entry into the charging system TS actions. Corrective measures were implemented to restore the inoperable heater, but subsequent inspections and actions by the licensee resulted in another heater being rendered degraded, but available for operation, over the course of a few days. The inspector reviewed the operations logs for the purpose of checking how this degraded heater condition was tracked.

While a priority alarm point log and a temporary log to inspect equipment conditions were available to the operators should the outside air temperature drop to 17° F, the inspector determined that the equipment checks would only verify electrical breaker position for the eight affected heaters, without noting or assessing the impact of degraded heater condition. The licensee issued a Condition Report Engineering Disposition (CRED) Form for CR M3-99-4183, documenting the nonconforming condition of the degraded heater assembly and the technical justification for operation of the heater. Upon further questioning by the inspector, the licensee confirmed that the operations logs, including any temporary logs created during the relevant time frame, did not document the

degraded (albeit available) condition of the nonconforming area heater. The licensee then issued another condition report , CR M3-00-0137, to document an inconsistent use in the Shift Turnover Log to track nonconforming or degraded conditions affecting safety-related component operability. The inspector discussed this issue with the Manager of Operations, reviewed all the relevant CRs and associated documentation, and determined that this was a minor tracking/documentation concern, since the degraded heater, while not fully operable, had been evaluated by engineering personnel for availability and operation.

Additionally, while assessing the licensee's response to some equipment problems with the Station Blackout (SBO) diesel generator start test in accordance with surveillance procedure SP 3646D.1, the inspector reviewed the relevant CRs (M3-00-31 & 00-47), noting that the licensee determined that the various equipment concerns and diesel start failures were not reportable to the NRC. The inspector also reviewed the system operating procedure, OP 3346D, for the Station Blackout Diesel and the Unit 3 Station Blackout Safe Shutdown Scenario Document, SP-EE-363 (Revision 3). It was noted that Battery 5 provides control power for load stripping of the normal bus and closing the SBO diesel generator tie breaker to either of the two vital 4.16 Kv buses. A battery 5 ground had been identified by the licensee during the same week of the SBO diesel generator outage and testing activities. The inspector questioned whether the impact of such grounded conditions would be appropriately reflected in the SBO diesel generator availability considerations.

As a result of the review of the identified SBO diesel generator problems, the inspector further discussed with the licensee's Regulatory Affairs personnel what criteria would be used to further assess the operability, reportability, and licensing-basis issues involving the SBO diesel generator. It was noted that the problems associated with CRs M3-00-0031 and 0047 were documented as maintenance rule functional failures. While the loss of all alternating current power is not a design-basis event at Unit 3, the SBO scenario is subject to regulatory requirements (10 CFR 50.63). The licensee's evaluation of the ability to "cope" with such a SBO scenario is available for NRC review. As a result of the problems documented in the CRs noted above, the licensee staff plans to further evaluate the handling of SBO equipment concerns, relative to the specific Unit 3 coping analysis.

During the conduct of several plant inspection-tours to check equipment status and verify proper operational controls, the inspector also examined the access points, postings, and barricades associated with radiological control areas (RCAs) and other radiation boundaries. One specific RCA boundary and posting within the Unit 3 auxiliary building was discussed further with the Station Radiological Protection Manager and determined to be consistent with the requirements of the health physics (HP) operations procedure, RPM 2.4.1 (Revision 2) for the "Posting of Radiological Control Areas". The inspector also discussed with HP technicians a recent change in the access point controls to the engineered safety features building and the segregation, marking, and control of materials planned for release from the auxiliary building RCA access point. Radiation area, RCA, and as-low-as-is-reasonably-achievable (ALARA) postings were found to be in compliance with the station radiation protection program requirements.

c. Conclusions

The established Unit 3 operational and radiological controls were adequate to provide for the safe implementation of plant evolutions and control room activities, as well as for the effective handling and tracking of plant equipment status. Issues involving component operability, availability, reportability, and regulatory compliance were appropriately addressed by the licensee staff.

U3.II Maintenance

U3 M1 Conduct of Maintenance

M1.1 Maintenance & Surveillance Observations

a. Inspection Scope (61726, 62707)

The inspector observed portions of the following maintenance and surveillance activities, discussed the conduct of work and controls with responsible personnel, and reviewed selected test results.

- SP 3614F.9 Control Building Chilled Water Valve Operability Test
- SP 3623.2-1 Cycle Test of HP Turbine Stop Valve and LP Turbine Combined Intermediate Stop and Intercept Valves (Weekly)
- M3-99-15721 Fiber Scope Inspection of Service Water Side of Containment Recirculation Pump Area Cooler Condenser Heat Exchanger (3HVQ*ACUS2B)

b. Observations and Findings

The inspector reviewed surveillance procedure, SP 3614F.9 (Revision 2), confirming adequate discussion and control of certain pieces of material and test equipment utilized in the conduct of the surveillance test. Two condition reports, CRs M3-99-4208 and 4209, were issued to document questions regarding valve stroke time limits. The inspector determined that the issue of valve "ISI Min/Max" stroke time deviations was handled separately from the "Design Limit" criteria, as was adequately discussed in the Surveillance Procedure instructions. The inspector discussed with the on-shift operators the usage of video camera equipment in the conduct of the surveillance activities. The inspector verified that sufficient procedural guidance and detail is specified to adequately control the practice of video timing valve strokes, but also noted the option for using a quality assurance (QA) stopwatch, at the discretion of the Shift Manager, for the conduct of second-stroke tests.

The inspector observed troubleshooting activities following the failure of the turbine, Number 5 combined intermediate stop and intercept valve (CIV) to fully stroke during the weekly performance of SP 3623.2-1. Operators entered applicable TS 3.3.4. Effective

communication was noted between operations, maintenance, instrumentation and control (I&C), and engineering personnel to plan and execute subsequent testing. Engineering personnel issued Memo No. MP-USE-99-029 to the shift manager documenting previous discussions with the turbine vendor which indicated that the turbine was designed such that it could be operated indefinitely with one CIV closed as long as no other operational concerns existed. The memo stated that preferred operation with one valve closed is two hours, but it may remain closed as long as reasonable efforts to restore it to operation are pursued. The prebrief for the retest of the affected CIV was given to involved personnel and focused on the actions to be performed by the various groups, communication, and contingencies. During the troubleshooting performance of the SP, the valve stroked as described by the surveillance procedure and no problems were detected in the field. Operators exited the TS LCO. The inspector determined that actions taken to this point were reasonable. In addition, the licensee planned to conduct this portion of the surveillance during day shift the following week, instead of on mids as is typical, to allow engineering and I&C personnel to support the activity. The inspector verified the testing was conducted as planned throughout the rest of the inspection period with no further problems identified

The inspector also observed system restoration activities on the "B" train engineered safety features (ESF) building ventilation system, noting plant equipment operators appropriately using the procedures, self-checking, and independent verification controls for component positioning and tagging. With respect to the calibration of heat tracing equipment, the inspector noted that updated tags were posted on the backup panel (3HTS-PNL-F2) for the heat tracing of safety-related components and piping. The inspector had previously confirmed that the licensee had performed the calibration activities in September 1999, consistent with the checks and calibrations of the primary heat tracing panel (3HTS-PNL-F1) equipment.

c. Conclusions

Observed Unit 3 surveillance and maintenance activities were well controlled and conducted in accordance with approved work orders and procedures. Appropriate corrective actions were taken when unanticipated testing results were obtained.

U3 M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Evaluation and Control of Scaffolding

a. Inspection Scope (62707)

The inspector reviewed the work control procedures governing the erection, engineering evaluation, and control of scaffolding located in proximity to safety-related equipment. The field conditions for one scaffold were examined, along with the authorizing work documents, the in-place tagging, and the procedurally required scaffolding checklist and evaluation.

b. Observations and Findings

The inspector reviewed the Common Maintenance Procedure, C MP 720A (Revision 2), on "Scaffold Erection, Use and Removal" and the Unit 3 procedure, U3 WC 1 (Revision 2), on work management, which includes specific instructions on "Scaffolding" in Attachment 10. The inspector noted in Attachment 10 a "caution" statement indicating, "Seismic requirements to ensure OPERABILITY of Safety Related equipment include a minimum 2 inch shake space between the scaffold and Safety Related equipment ... " and, "If shake space is less than 2 inches, supplementary instructions are required to ensure seismic interaction will not impact OPERABILITY of Safety Related equipment."

During an inspection-tour of the main steam and feedwater valve building, the inspector examined a scaffold erected in proximity to a feedwater containment isolation valve, 3FWS*CTV41B. Tags were affixed to the scaffolding and documented the appropriate information, including the automated work order (AWO) for the scaffold erection, as well as the AWO for the maintenance activity that required the scaffolding to remain in place. The inspector noted that parts of the scaffold were closer than two inches to some of the safety-related components in the area; with one example of a safety-related main steam system pressure transmitter (3MSS*PT525) approximately one-half inch from the erected scaffolding tube steel.

The inspector reviewed the scaffolding erection work order, AWO M3 99 15231, noting that the scaffolding checklist and evaluation (Attachment 10.2) supplementary instructions recognized the two inch clearance criterion between the scaffold and safety-related equipment in the area. However, an engineering review following the post-installation walk-down noted that while the two inch criterion could not be met, the rigidity of the scaffolding, when shaken, was sufficient to prevent contact. The inspector questioned whether this post-installation engineering review was sufficient to meet the intent of the "seismic requirements" of procedure U3 WC 1. The inspector noted that a seismic induced hazards review, including visual inspection of the separation and clearances between installed components, was a design consideration documented in Specification SP-ME-810.

Further discussion with licensee engineering representatives revealed that the existing documentation regarding the potential effect of the subject scaffolding on safety-related components did not meet the intent of the procedural requirements and was not sufficient. The licensee issued condition report CR M3-00-0098 to document this discrepancy. The recommended corrective actions include more explicit details in the evaluation when the specified criteria are not met and contact with Design Engineering when deviations are identified. The inspector verified that the work requiring erection of the subject scaffolding had been completed and that the scaffold was scheduled for removal.

The inspector determined that failure to adequately document supplementary instructions for potential seismic interactions of scaffolding and plant equipment, when the "shake space is less than 2 inches", represented a violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings". However, based upon the

licensee's issuance of CR M3-00-0098 and planned corrective actions, noted above; and also consistent with Section VII.B.1.a of the NRC Enforcement Policy, this Severity level IV violation is being treated as a Non-Cited Violation.

c. Conclusions

Review of the licensee's work control procedures governing the erection of scaffolding identified adequate controls and engineering directions. However, some Unit 3 scaffolding was identified by NRC field inspection to be in violation of the procedural provisions for ensuring that seismic interactions would not impact the operability of nearby safety-related equipment. This failure to follow procedures is being treated as a **Non-Cited Violation (NCV 50-423/99-14-08)**.

U3 M8 Miscellaneous Maintenance Issues

M8.1 (Closed) IFI 50-423/96-09-15; Millstone Unit 3 Safeguards Equipment Room Ventilation & Coolers Excluded From High Risk Without Completing Room Heat Load Calculations

a. Inspection Scope (92902)

The inspectors reviewed the licensee's response and related actions to address Inspector Follow-up Item (IFI) 50-423/96-09-15. This IFI was opened to review Unit 3 safeguards equipment room ventilation and coolers which had been excluded from being classified as high risk significant systems without completing room heat load calculations.

The inspectors conducted in-office and onsite reviews of the IFI. This review included a review of Unit 3 engineering and maintenance rule procedures, associated engineering evaluations/memorandums, work activities, and corrective action documents in the licensee's corrective action process. In addition, these items were discussed with safety analysis engineers and the affected system engineers.

b. Observations and Findings

The licensee completed associated heat load calculations and technical evaluations summarized in Engineering Record Correspondence 25203-ER-99-1001. The following system/functions were recommended reclassified as risk significant: Auxiliary Building heating ventilation and air conditioning (HVAC) system for reactor plant chilled water and charging systems; Control Building HVAC and Chilled Water for the East and West Switchgear Rooms; ESF Building HVAC; and Intake Structure Ventilation for Service Water. The Maintenance Rule Expert Panel met on September 23, 1999, and revised the risk significance determination and performance measures for the above systems with the exception of the Control Building HVAC and Chilled Water for the East and West Switchgear Rooms (expert panel meeting minutes, memo PEG-99-019).

The licensee determined that the initial heat load calculation and technical evaluation for the Control Building HVAC and Chilled Water for the East and West Switchgear Rooms had been overly conservative based on estimated heat loads. The system engineer

prepared a technical evaluation based on more realistic/actual heat loads in these areas (M3-EV-99-0114). The safety analysis engineering group will prepare a calculation to support the results of the technical evaluation with an estimated completion date of January 31, 2000, and the expert panel is scheduled to review the results of the technical evaluation and calculation by February 28, 2000 (CR M3-99-1285, AR # 99006693, assignments 9 and 10).

c. Conclusion

The licensee's action to re-evaluate the risk significance of the Unit 3 safeguards equipment room ventilation and coolers and to establish appropriate performance measures for these areas was acceptable and complete with the exception of the East and West Switchgear Rooms. This remaining item to reverify the heat loads and confirm risk significance for the heating, ventilation and air conditioning system will be closed based on the licensee tracking completion of all corrective actions associated with CR M3-99-1285, which is scheduled for completion February 28, 2000. **IFI 50-423/96-09-15** is **closed**.

M8.2 (Closed) IFI 50-423/97-80-05; Balancing Reliability and Unavailability

a. Inspection Scope (92902)

The inspectors reviewed the licensee's response and related actions to address Inspector Follow-up Item (IFI) 50-423/97-80-05. This IFI was opened to review the licensee's ability to effectively balance reliability and unavailability after the unit had been operating for a period of time and the licensee had an opportunity to gather real plant data related to system performance.

The inspectors conducted in-office and onsite reviews of the IFI. This review included a review of Unit 3 engineering and maintenance rule procedures, associated engineering evaluations/memorandums and corrective actions documents in the licensee's corrective action process. In addition, the item was discussed with system engineers and the maintenance rule coordinators.

b. Observations and Findings

The item on balancing reliability and unavailability is closed based on a review of the completed Unit 2 & 3 maintenance rule periodic assessment reports dated July 10, 1998, and the joint (Units 2 & 3), "Periodic Assessment of Maintenance Rule Program" report, dated December 17, 1999, which appropriately addressed balancing reliability and unavailability as defined in 10 CFR 50.65 (a)(3). Balancing reliability and unavailability program requirements were described in Attachment 1 to Engineering Department Instructions (EDI) No. 30740, "Maintenance Rule Periodic Assessment". Several items remained open from the Units 2 & 3 past periodic assessments completed in May 1998, and are being tracked under CRs identified in Attachment 8-1 of the recently completed periodic assessment dated December 17, 1999.

c. Conclusion

The licensee appropriately completed two periodic assessments for each unit which addressed balancing reliability and unavailability as described in 10 CFR 50.65(a)(3). The licensees process for balancing reliability and unavailability was sound. **IFI 50-423/97-80-05** is **closed**.

M8.3 (Closed) IFI 50-423/98-02-03; Millstone Unit 3 Evaluation and Resolution of Condition Report M3-98-1976 on High Confidence Level of Reliability Performance Measures

a. Inspection Scope (92902)

The inspectors reviewed the licensee's response and related actions to address Inspector Follow-up Item (IFI) 50-423/98-02-03. Both the Millstone Unit 3 NRC Operational Safety Team Inspection and the Maintenance Rule baseline team inspection (May 1998) had concluded that a number of high risk significant SSCs had reliability performance measures that were set too high for Unit 3. This IFI noted that the licensee had identified the need to review Unit 3 reliability performance criteria for all high risk significant systems, as indicated in Condition Report (CR) M3-98-1976 (April 15, 1998). The review of the performance measures had not started at the time of the maintenance baseline team inspection in May 1998, therefore, this IFI had been opened to verify the licensees's review and resolution of this item which had a scheduled completion date of October 16, 1998.

The inspectors conducted onsite reviews of the IFI. This review included a review of Unit 3 engineering and maintenance rule procedures, associated engineering evaluations/memorandums and corrective actions documents in the licensee's corrective action process. In addition, the item was discussed with the site supervisor for PRA and the maintenance rule coordinator for Unit 3.

b. Observations and Findings

The inspectors noted that the licensee had originally used the EPRI guidance of 1% (measure of confidence level) to determine the acceptable reliability performance measures for risk significant systems. Late in 1997, subsequent to Millstone 3 calculations, standard industry practice became the use of EPRI guidance of 5% (measure of confidence level). Since the 5% method is more conservative, a recalculation could result in fewer functional failures (more conservative performance criterion) being allowed for risk significant systems. This method (i.e., EPRI guidance of 5%) was also endorsed by the NRC staff as one of two acceptable methods of determining performance measures in "Supplemental Maintenance Rule Inspection Guidance, Section VI, Inspection Guidance for Reliability and PRA Specialists," dated February 2, 1998.

The inspectors reviewed PRA memo number NE-98-SAB-127, "Maintenance Rule Functional Failure Performance Criteria Validation," dated August 31, 1998, which recommended that numerous performance measure values in various risk significant

SSCs be revised to be in line with the current and more conservative industry standards. The basis for these recommended changes was "NUSCO PSA Guideline No. 6 (dated October 7, 1997), Technical Basis for Functional Failure Count Performance Criteria". At the time of the inspection, this guideline based on EPRI guidance of 5% (i.e., to determine the acceptable reliability performance measures for high risk significant systems) had been adopted by the licensee for Unit 2 but had not been fully implemented for Unit 3.

The inspectors noted that for at least one example (Station Blackout (SBO) Diesel), the recommended PRA/industry based standard criteria of less than two functional failures had been exceeded. The failures occurred during quarterly preventive maintenance (PM) for the 125 volt SBO diesel battery bank (CR M3-98-3650) and following restoration from tagging for PM (CR M3-99-1106). The inspectors reviewed the details of these two functional failures and the licensee's corrective actions and determined that no operability issues currently exist regarding these failures. However, had the new performance measures been adopted, the licensee would have been obligated to place the diesel in an (a)(1) status and establish appropriate goals in the general time frame of April 13, 1999, following the second functional failure. Furthermore, for approximately 14 high risk significant SSCs, the PRA/industry recommended performance measures had never been adopted as of the end date of this inspection (December 14, 1999), approximately 15 months after issuance of the PRA memo (NE-98-SAB-127). The licensee initiated CR M3-99-3966 the week before this inspection, when the expert panel met and was not able to resolve this issue.

Also, the inspectors discussed with the Unit 3 maintenance rule coordinator the method the licensee had used for establishing performance measures for the emergency diesel generators (EDGs) and SBO diesel. The Unit 3 maintenance rule coordinator indicated that these performance measures had been established based on suggested trigger values recommended in NUMARC 87-00. The inspectors noted that in Generic Letter 94-01, "Removal of Accelerated Testing and Special Reporting Requirements for Emergency Diesel Generators," dated May 31, 1994, that the staff had voiced a concern over use of the trigger values identified in NUMARC 87-00 for the purposes of monitoring EDG performance.

This area is unresolved pending further NRC evaluation of whether a violation of 10 CFR 50.65(a)(1) and (a)(2) occurred with respect to: (1) the licensee's methods for establishing performance measures for high risk significant SSCs for Unit 3; (2) failure of the licensee to place the SBO Diesel in an (a)(1) status and to establish appropriate goals in the general time frame of April 13, 1999 following the second functional failure; (3) the licensee's method of establishing performance measures for the emergency diesel generators (EDGs) and SBO diesel. **(Unresolved Item 50-423/99-14-09)**

c. Conclusion

This area is unresolved pending further NRC evaluation of whether a violation of 10 CFR 50.65(a)(1) and (a)(2) occurred with respect to: (1) the licensee's methods for establishing performance measures for high risk significant SSCs for Unit 3; (2) failure of

the licensee to place the SBO Diesel in an (a)(1) status and to establish appropriate goals in the general time frame of April 13, 1999, following the second functional failure; (3) the licensee's method of establishing performance measures for the emergency diesel generators (EDGs) and SBO diesel **(Unresolved Item 50-423/99-14-09)**. **IFI 50-423/98-02-03** is **closed**.

U3.III Engineering

U3 E1 Conduct of Engineering

E1.1 Engineering Review of Component Corrosion

a. Inspection Scope (37551)

The inspector reviewed the licensee engineering evaluation and response to NRC questions regarding evidence of galvanic corrosion on some stainless steel valves in the safety injection portion of the residual heat removal (RHR) system.

b. Observations and Findings

The inspector discussed with the cognizant licensee system engineer the observation of the appearance of galvanic corrosion on four safety-related, manual drain valves located in the RHR vaults in the engineered safety features building. The four safety injection, globe valves (3SIL*V996 thru V999) are provided as leakage monitoring connections in the suction flow paths to the RHR pumps. Engineering review confirmed that the valve components are fabricated of stainless steel material and that the corrosion on the valve body, yoke and bolts is galvanic in nature.

The inspector reviewed a licensee memorandum (ME-WM-99-323), dated December 8, 1999, from the licensee's Material Engineering group, that evaluated the observed corrosion, its probable causes and impact, and potential solutions to prevent further degradation. It was determined that a boric acid solution created by small valve leaks coupled with condensation from piping above was sufficient to electrolytically cause the galvanic corrosion between the different stainless steel material parts making up the subject valves. The structural integrity of these valves was not compromised by this condition, based upon an assumed corrosion rate consistent with the boric acid concentrations and conservative moisture and temperature conditions. Since similar valves with insulated piping above them did not exhibit corrosion, a recommendation was made to insulate the bare pipe to eliminate the moist atmosphere and thus one electrolytic cause of the corrosion.

c. Conclusions

The licensee system engineer appropriately conducted follow-up of observed corrosion on some safety-related Unit 3 valves. Material engineers evaluated the as-found conditions in the plant, determined that the immediate, adverse safety impact was

minimal, and recommended a solution to eliminate further corrosion as a longer term corrective action. Overall licensee response to this issue was good.

E1.2 Year 2000 Project Readiness Review

Please refer to Section U2.E1.1 of this report for a discussion of this area.

U3 E2 Engineering Support of Facilities and Equipment

E2.1 Turbine Driven Auxiliary Feedwater Pump Discharge Isolation Valves Fail to Stroke

a. Inspection Scope (37551, 71707, 62707)

On the evening of December 20, and early morning on December 21, 1999, the "A" and "D" turbine driven auxiliary feedwater (TDAFW) pump discharge isolation valves (3FWA*HV36A/D) failed to stroke closed during routine surveillances. The inspector discussed the failures with operations and engineering personnel; observed licensee troubleshooting activities in the control room and in the plant; and reviewed applicable design documentation, procedures, and prints.

b. Observations and Findings

The licensee issued CRs to document the failure of the "A" isolation valve to stroke closed (CR M3-99-4132) and the slow closure of the "D" TDAFW pump discharge isolation valve (CR M3-99-4135). Operators correctly entered TS 3.6.3 for containment isolation valves and closed and de-energized a manual valve in each line upstream of the subject isolation valves, as required by the action statement. Another safety function for these valves is to open to allow AFW flow to the steam generators. Therefore, with these manual valves closed, the TDAFW system to these generators was inoperable. As a result, operators properly entered TS 3.7.1.2.a, which has a 72 hour shutdown action statement for this condition.

The inspector observed effective communication among engineering, operations, maintenance, and work planning personnel to troubleshoot these valves in a timely manner. Subsequent field testing was well controlled and performed in accordance with approved procedures and work orders.

Engineering personnel discussed the observed problems with the valve vendor, Target Rock. The vendor confirmed that these valves are meant to function with a differential pressure across them. The testing performed in the surveillance is essentially static, thereby making closure difficult. (Both valves closed in subsequent testing at much greater times than allowed in the surveillance.) The valves are normally open and receive no automatic signal. The surveillance test specifies stroking the valves and timing the stroke for Inservice Testing (IST) for the purpose of monitoring and trending any valve degradation. There is no stroke time required for the valves by the design basis, as stated in the FSAR. The licensee and vendor agreed that ideally these valves should be tested with a differential pressure across them, as would typically be seen

during accident conditions. The licensee initiated an action item in their corrective action plan to develop an alternate test method for these valves ("A", "B", "C", and "D").

Notwithstanding the design-basis valve function, discussed above, these valves are also containment isolation valves (CIVs), which operators would need to be able to close with or without a differential pressure across them. Therefore, to declare the valves operable, the licensee needed to be able to also address the CIV function. The licensee prepared operability determinations (ODs), MP3-037-99 and MP3-038-99, for these valves. The ODs thoroughly discuss the function and design of the valves and address the containment isolation function. It was demonstrated that operators can "bump" the valves closed from the control room by manipulating the power provided to the valves' solenoids at the controllers. The inspector noted that caution tags, identifying this condition to the operators and providing such direction, have been placed at the controls for all four TDAFW pump discharge isolation valves. In addition, another action item was created to modify the applicable procedures to alert operators to this operation of the valves, if needed. The inspector verified that the identified problems and licensee corrective actions would not adversely impact the safety-related "open" function of the valves.

c. Conclusions

Unit 3 personnel properly control and conducted troubleshooting activities for the "A" and "D" turbine driven auxiliary feedwater (TDAFW) pump discharge isolation valves' failure to close on December 20, 1999. Operators properly entered and complied with applicable TS LCOs for containment isolation and auxiliary feedwater. Operability Determinations written to address the issue provided a logical basis for operability of the valves for the AFW and containment isolation functions. Caution tags on the main control boards provide operators important information regarding operation of the valves if problems are encountered during future manual valve manipulation.

U3 E8 Miscellaneous Engineering Issues

E8.1 (Closed) Violation 50-423/98-81-01; Fire Barrier between the Unit 3 Cable Spreading Room and the Unit 3 Control Room

a. Inspection Scope (37550, 92700, 92903)

The inspector reviewed the licensee's corrective actions to address Violation (VIO) 50-423/98-81-01.

b. Observations and Findings

Violation 50-423/98-81-01 involved a failure to provide an adequate fire barrier between the Unit 3 cable spreading and control rooms, as a result of not protecting certain fire barrier support steel columns from the effects of an exposed fire in the cable spreading room.

The licensee responded to the violation in a Northeast Nuclear Energy letter, B87279, dated June 22, 1998. The licensee's corrective actions included engineering calculations that verified the 3-hour rating of the cable spreading room ceiling. This issue was entered into the licensee's corrective action process as Condition Report M3-98-1332.

The licensee's corrective actions in response to the violation were determined to be acceptable. Violation 50-423/98-81-01 is closed.

c. Conclusions

The licensee's corrective actions to ensure the 3-hour fire rating of the Unit 3 cable spreading room ceiling, in response to an NRC violation were acceptable. Therefore, **Violation 50-423/98-81-01** is **closed**.

E8.2 (Closed) Violation 50-423/98-81-02; Multiple High Impedance Faults during a Postulated Control Room Fire

a. Inspection Scope (37550, 92700, 92903)

The inspector reviewed the licensee's corrective actions to address Violation (VIO) 50-423/98-81-02.

b. Observations and Findings

Violation 50-423/98-81-02 involved the failure of the licensee to ensure that certain vital alternating current power panels were not susceptible to multiple high impedance faults (MHIF) which could result in blowing the main power supply fuses.

The licensee responded to the violation in a Northeast Nuclear Energy letter, B17279, dated June 22, 1998. The licensee's corrective actions included drawing changes, panel modifications (including panel bypass switches), and engineering calculations. The engineering calculations verified incoming 150 ampere fuses for vital panels and 40 ampere fuses for non-vital panels would not blow due to MHIF. This issue was entered into the licensee's corrective action process as Condition Report M3-97-4684.

The licensee's corrective actions in response to the violation were determined to be acceptable. Violation 50-423/98-81-02 is closed.

c. Conclusions

In response to an NRC violation, the licensee initiated adequate corrective actions to ensure certain vital, alternating current, power panels were not susceptible to multiple high impedance faults. Therefore, **Violation 50-423/98-81-02** is **closed**.

E8.3 (Closed) Violation 50-423/98-206-04; Operator Performance Time to Isolate a Design Basis Steam Generator Tube Rupture

a. Inspection Scope (37550, 92700, 92903)

The inspector reviewed the licensee's corrective actions to address Violation (VIO) 50-423/98-206-04.

b. Observations and Findings

Violation 50-423/98-206-04 involved a failure to implement prompt corrective actions regarding assumed operator performance time to isolate a steam generator tube rupture (SGTR).

The licensee responded to the violation in a Northeast Nuclear Energy letter, B817161, dated June 26, 1998. The licensee's corrective actions included engineering calculations that verified the SGTR assumptions. SGTR scenario data was forwarded to the NRC in Northeast Nuclear Energy letter, B816020, verifying that an overall crew response to a postulated SGTR would not include a steam generator overfill condition. This issue was entered into the licensee's corrective action process as Condition Reports M3-98-2746 and M3-96-0875.

The licensee's corrective actions in response to the violation were determined to be acceptable. Violation 50-423/98-206-04 is closed.

c. Conclusions

The licensee's corrective actions to ensure appropriate operator actions during a postulated steam generator tube rupture, in response to an NRC violation, were acceptable. Therefore, **Violation 50-423/98-206-04** is **closed**.

E8.4 (Closed) Violation 50-423/98-207-15; Material, Equipment and Parts List Components

a. Inspection Scope (37550, 92700, 92903)

The inspector reviewed the licensee's corrective actions to address Violation (VIO) 50-423/98-206-04.

b. Observations and Findings

Violation 50-423/98-207-15 involved a failure to perform specific Material, Equipment and Parts List (MEPL) maintenance work and/or purchase history reviews. This resulted in non-safety related parts being procured and installed in American Society of Mechanical Engineers (ASME) components.

The licensee responded to the violation in a Northeast Nuclear Energy letter, B817361, dated July 17, 1998. The licensee's corrective actions included operability

determinations and engineering calculations that verified the operability of each of the affected ASME components. Additional corrective actions included MEPL procedure and process changes. This issue was entered into the licensee's corrective action process as Condition Reports M3-98-3111, 1806, 1807 and 2667.

The licensee's corrective actions in response to the violation were determined to be acceptable. Violation 50-423/98-207-15 is closed.

c. Conclusions

The licensee's corrective actions to ensure appropriate MEPL maintenance work and/or purchase history reviews, in response to an NRC violation, were acceptable. Therefore, **Violation 50-423/98-207-15** is **closed**.

IV Plant Support
(Common to Unit 2 and Unit 3)

S1 Conduct of Security and Safeguards Activities

a. Inspection Scope (81700)

Determine whether the conduct of security and safeguards activities met the licensee's commitments in the NRC-approved security plan (the Plan) and NRC regulatory requirements. The security program was inspected during the period of December 6-9, 1999. Areas inspected included: Access Authorization (AA) program; alarm stations; communications; and protected area (PA) access control of personnel and packages.

b. Observations and Findings

Access Authorization Program. The AA program was reviewed to verify implementation was in accordance with applicable regulatory requirements and Plan commitments. The review included an evaluation of the effectiveness of the AA procedures, as implemented, and an examination of AA records for ten individuals. Records reviewed included both persons who had been granted and had been denied access. The AA program, as implemented, provided assurance that persons granted unescorted access did not constitute an unreasonable risk to the health and safety of the public. Additionally, access denial records and applicable procedures were reviewed to verify that appropriate actions were taken when individuals were denied access or had their access terminated.

Alarm Stations. Operations of the Central Alarm Station (CAS) and the Secondary Alarm Station (SAS) were reviewed. Both alarm stations were determined to be equipped with appropriate alarms, surveillance and communications capabilities. The inspector interviewed the alarm station operators and found them knowledgeable of their duties and responsibilities. Observations and interviews also verified that the alarm stations were continuously manned, independent and diverse so that no single act could remove the plant's capability for detecting a threat and calling for assistance. The alarm stations did not contain any operational activities that could interfere with the execution of the detection, assessment and response functions.

Communications. Document reviews and discussions with alarm station operators and response force members determined that there was a problem with the security radio system. The radio system had recently been replaced with a new system in an attempt to eliminate or minimize the number of areas in the plant where hand-held radios could not transmit or receive. However, the new radio system increased, instead of decreased, the number of areas where the radios could not be used. The licensee had identified this problem and was attempting to resolve this issue since effective communications are critical to the security organization meeting its regulatory responsibility. The licensee issued Condition Report M3-99-4032 to address this issue and pending resolution of the problem, alternate methods of communications have been implemented.

Protected Area Access Control of Personnel and Hand-Carried Packages. On December 7 and 8, 1999, during peak activity periods, personnel and package search activities were observed at the personnel access portal. Positive controls were determined to be in place to ensure only authorized individuals were granted access to the Protected Area (PA) and that all personnel and hand-carried items entering the PA were properly searched.

c. Conclusions

The licensee was conducting its security and safeguards activities in a manner that protected public health and safety. This portion of the program met the licensee's commitments and NRC requirements. A weakness was identified in the effectiveness of the security communications system. This weakness has been entered in the licensee's corrective action program.

S2 Status of Security Facilities and Equipment

a. Inspection Scope (81700)

Areas inspected were Protected Area (PA) assessment aids, PA detection aids and personnel search equipment.

b. Observations and Findings

Assessment Aids. On December 7 and 8, 1999, the effectiveness of the assessment aids was evaluated by observing the PA perimeter on closed circuit television (CCTV) in the Central Alarm Station (CAS). The evaluation of the assessment aids was accomplished by observing, on CCTV, a security force member (SFM) performing a perimeter patrol. The assessment aids generally had good picture quality, view and zone overlap. Additionally, to ensure Plan commitments were satisfied, the licensee had procedures in place requiring the implementation of compensatory measures in the event the alarm station operator was unable to properly assess the cause of an alarm.

PA Detection Aids. On December 7 and 8, 1999, while observing the assessment aids, testing was also observed of selected intrusion detection zones in the plant protected area. The appropriate alarm was generated in each zone for each test. Through observations and review of the testing documentation associated with the equipment repairs, the inspector verified that repairs were made in a timely manner and that the equipment was functional and effective, and met the commitments in the Plan.

Personnel and Package Search Equipment. On December 8, 1999, both the routine use and the daily operational testing of the licensee's personnel and package search equipment were observed. Personnel search equipment was being tested and maintained in accordance with licensee procedures and the Plan, and personnel and packages were being properly searched prior to protected area access.

Observations and procedural reviews determined that the search equipment performed in accordance with licensee procedures and Plan commitments.

c. Conclusions

The licensee's security facilities and equipment were determined to be well maintained and reliable and were able to meet the licensee's commitments and NRC requirements.

S3 Security and Safeguards Procedures and Documentation

a. Inspection Scope (81700)

Areas inspected were implementing procedures and security event logs.

b. Observations and Findings

Security and Program Procedures. Review of selected security program implementing procedures, associated with personnel search, vehicle search and equipment testing verified that the procedures were consistent with the Plan commitments.

Security Event Logs. The Security Event Logs for the previous twelve months were reviewed. Based on this review, and discussion with security management, it was determined that the licensee analyzed, tracked, addressed and documented safeguards events. Review of the logs disclosed that control of Safeguards information (SGI) continues to be a problem. Since the beginning of 1999, there have been seven events that were logged involving control of SGI. The licensee has consolidated these events into one corrective action. This issue is being addressed in Condition Report M3-99-4051.

c. Conclusions

Security and safeguards procedures and documentation were being properly implemented. Event Logs were being properly maintained and used to analyze, track, and address safeguards events.

S4 Security and Safeguards Staff Knowledge and Performance

a. Inspection Scope (81700)

Area inspected was security staff requisite knowledge.

b. Observations and Findings

Security Force Requisite Knowledge. A number of security force members (SFMs) were observed in the performance of their routine duties. These observations included alarm station operations, personnel and package searches, and exterior patrol alarm response. Additionally, SFMs were interviewed and based on the responses to questioning, it was

determined that the SFMs were knowledgeable of their responsibilities and duties, and could effectively carry out their assignments.

Response Capabilities. Discussions with the training staff and review of documentation of contingency response drills and critiques disclosed that the licensee is conducting drills. However, few drills are being documented. The overall effectiveness of the drill program could not be evaluated due to the lack of documentation. The licensee is addressing this issue in Condition Report M3-99-4034.

c. Conclusions

The SFMs adequately demonstrated that they had the requisite knowledge necessary to effectively implement the duties and responsibilities associated with their position. Response capabilities could not be evaluated due to a lack of documentation for drills, which is being addressed by the licensee's corrective action program.

S5 Security and Safeguards Staff Training and Qualification

a. Inspection Scope (81700)

Areas inspected were security training and qualifications and training records.

b. Observations and Findings

Security Training and Qualifications. On December 8, 1999, Training & Qualification records of eight security force members (SFMs) were reviewed. The results of the review indicated that these personnel met the annual requalification requirements in the approved Training & Qualifications (T&Q) plan.

Training Records. Through review of training records, it was determined that the records contained a certification that the training had been conducted, but no supporting documentation was available. The weakness in the training records is being addressed in Condition Report M3-99-4034.

c. Conclusions

Security force personnel were being trained in accordance with the requirements of the T&Q Plan. Training documentation was weak and is being addressed in the licensee's corrective action program.

S6 Security Organization and Administration

a. Inspection Scope (81700)

Areas inspected were management support and staffing levels.

b. Observations and Findings

Management Support. Review of program implementation since the last program inspection disclosed that adequate support and resources continued to be available to ensure effective program implementation.

Staffing Levels. The total number of trained security force members (SFMs) immediately available on shift met the requirements specified in the Plan and implementing procedures.

c. Conclusions.

The level of management support was adequate to ensure effective implementation of the security program, and was evidenced by the allocation of resources to support programmatic needs.

S7 Quality Assurance in Security and Safeguards Activities

a. Inspection Scope (81700)

Areas inspected were audits, problem analyses, corrective actions and effectiveness of management controls.

b. Observations and Findings

Audits. The 1999 Quality Assurance (QA) Security Program Audit was reviewed. Review of the audit disclosed that it was comprehensive in scope and depth.

Problem Analyses. A review of data derived from the security department's self-assessment program indicated that potential weaknesses were being properly identified, tracked, and trended.

Corrective Actions. Review of corrective actions implemented by the licensee, in response to the QA audits and self-assessment program, disclosed that all corrective actions had been implemented.

Effectiveness of Management Controls. The licensee had programs in place for identifying, analyzing and resolving problems. They include the performance of annual QA audits and a departmental self-assessment program.

c. Conclusions

The review of the licensee's audit program indicated that the security program audits were comprehensive in scope and depth, that findings were reported to the appropriate level of management, and that the program was being properly administered. In addition, a review of the documentation applicable to the security self-assessment

program indicated that the program was being implemented to identify and resolve potential weakness.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection. The licensee acknowledged the findings presented.

X3 Management Meeting Summary

On December 15, 1999, a public meeting was held at Millstone Station between NU and the NRC Millstone Assessment Panel to discuss Enhanced Performance System, Emergency Preparedness, Unit Status, Backlog Reduction, and Safety Conscious Work Environment. Slides from the meeting are attached to this report.

INSPECTION PROCEDURES USED

IP 37550	Engineering
IP 37551	Onsite Engineering
IP 61726	Surveillance Observations
IP 62707	Maintenance Program
IP 71707	Plant Operations
IP 71750	Sustained Control Room and Plant Observation
IP 81700	Physical Security Program for Power Reactors
IP 92700	Onsite Follow-up of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92902	Follow-up Maintenance
IP 92903	Follow-up Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-336/99-14-01	NCV	Failure to place RPS into a Maintenance Rule (a)(1) status
50-336/99-14-02	NCV	Failure to establish and implement adequate testing of the safety injection recirculation header (related to LER 50-336/98-20-00)
50-336/99-14-03	NCV	Failure to establish and implement adequate CAR fan testing (related to LER 50-336/98-23-00)
50-336/99-14-04	NCV	Failure to establish and implement adequate testing of certain check valves (related to LER 50-336/98-25-00)
50-336/99-14-05	NCV	Failure to adequately establish and implement design controls associated with safety-related cable tray spacing and placement (related to LER 50-336/98-18-00 & 01)
50-336/99-14-06	NCV	Failure to adequately establish and implement design controls to ensure that the safety-related design bases for containment pressure instruments were correctly translated into specifications, drawings and procedures (related to LER 50-336/98-24-00)
50-336/99-14-07	NCV	Failure to adequately establish and implement design controls for the pressurizer spray line design criteria (related to LER 50-336/98-26-00)
50-423/99-14-08	NCV	Failure to adequately document supplementary instructions for potential seismic interactions of scaffolding and plant equipment
50-423/99-14-09	URI	Adequacy of performance measures for high risk significant SSCs

Closed

The NCVs opened above are closed.

50-336/98-02-01	IFI	Implementation Maintenance Rule Issues: (1) System Engineer Determination of Maintenance Rule Functional Failures and (2) Licensee's Action to Clarify Definitions of Functional Boundaries Between Interfacing and Overlapping Systems
50-336/98-02-02	IFI	Implementation Maintenance Rule Issues: (1) Review Effectiveness of Licensee's Maintenance and Performance Monitoring; (2) Balancing Reliability and Unavailability and (3)&(4) Review Operators Knowledge and Use of On-Line Maintenance Risk Assessment
50-336/98-206-02	URI	Safety Parameter Display System
50-423/96-09-15	IFI	Millstone 3's Safeguards Equipment Room Ventilation & Coolers Excluded From High Risk Without Completing Room Heat Load Calculations
50-423/97-80-05	IFI	Balancing Reliability and Unavailability
50-423/98-02-03	IFI	Millstone 3's Evaluation and Resolution of Condition Report M3-98-1976 on High Confidence Level of Reliability Performance Measures

50-423/98-81-01	VIO	Fire Barrier between the Unit 3 Cable Spreading Room and the Unit 3 Control Room
50-423/98-81-02	VIO	Multiple High Impedance Faults during a Postulated Control Room Fire
50-423/98-206-04	VIO	Operator Performance Time to Isolate a Design Basis Steam Generator Tube Rupture
50-423/98-207-15	VIO	Material, Equipment and Parts List Components

Discussed

None

The following LERs were also closed during this inspection:

LER 50-336/98-16-00	Safety Injection System Administrative Controls
LER 50-336/98-18-00 & 01	Spacial Separation of Redundant Cables
LER 50-336/98-19-00	Auxiliary Feedwater Regulating Valve Response to a High Energy Line Break
LER 50-336/98-20-00	Safety Injection Recirculation Header Inservice Visual Inspection Requirements
LER 50-336/98-23-00	Containment Air Recirculation Fan Testing
LER 50-336/98-24-00	Potential Containment Leakage Path
LER 50-336/98-25-00	Check Valve Testing Requirements
LER 50-336/98-26-00	Pressurizer Spray Line Fatigue Limits
LER 50-336/99-011-00	Exceeding the Thermal Reactor Power Limit

LIST OF ACRONYMS USED

AFW	auxiliary feedwater
ALARA	as low as is reasonably achievable
ASME	American Society of Mechnical Engineers
AWOs	automated work orders
CAR	containment air recirculation
CAS	central alarm system
CCTV	closed circuit television
CIV	combined intermediate stop and intercept valve
CRAC	control room air conditioning
CRED	Condition Report Engineering Disposition
EDI	Engineering Department Instruction
ESF	engineered safety features
FDSSS	flow dependent setpoint selector switch
FSAR	Final Safety Analysis Report
HP	health physics
HVAC	heating ventilation and air conditioning
I&C	instrumentation and control
IEEE	Institute of Electrical Electronic Engineers
IFI	inspector follow-up
IST	inservice testing
LCOs	limiting conditions for operations
LER	Licensee Event Report
LOCA	loss of coolant accident
MEPL	Material Equipment and Parts List
MHIF	multiple high impendance faults
MRFF	Maintenance Rule Functional Failures
OD	operability determinations
PA	protected area
PRA	probabilistic risk assessment
QA	quality assurance
QSS	quench spray system
RBCCW	reactor building closed cooling water
RCAs	radiological control areas
RCP	reactor coolant pump
RHR	residual heat removal
RPS	reactor protection system
SAS	secondary alarm system
SBO	station blackout
SIT	safety injection tanks
SFM	security force member
SGI	safeguards information
SGTR	steam generator tube rupture
SI	safety injection
SPDS	safety parameter display system
SR	surveillance requirement

SSC	structure, system, or component
T&Q	training and qualification
TDAFW	turbine driven auxiliary feedwater
the Plan	NRC-approved physical security plan
TM/LP	thermal margin/low pressure
TS	technical specification
URI	unresolved item
VIO	violation
VT	visual testing

NU/NRC MILLSTONE ASSESSMENT PANEL PUBLIC MEETING

ENHANCED PERFORMANCE SYSTEM, EMERGENCY PREPAREDNESS, UNIT STATUS, BACKLOG REDUCTION, AND SAFETY CONSCIOUS WORK ENVIRONMENT

DECEMBER 15, 1999

NORTHEAST UTILITIES BRIEFING SLIDES

Northeast Utilities Briefing for the NRC Millstone Assessment Panel

Millstone Station
December 15, 1999

Northeast Utilities Agenda

- Enhanced Performance System
- Emergency Preparedness
- Unit Status
- Backlog Reduction
- SCWE
- Closing Remarks

Enhanced Performance System

Mike Brothers
Vice President - Operations

EPS Level 1-November 1999

Safety Y	Nuclear Safety (Schwarz) Y Y W W	Human Performance (Schwarz) Y Y Y Y Y	Industrial Safety (Hoisington) R R R R R	Radiation Safety (Schwarz) Y W W W	Environmental Performance (Jacobson) Y Y R R R	
Operational Excellence Y	Work Planning & Outage Management (Brinkman) R W Y Y Y	Maintenance (Jordan) R R Y Y Y	Management (Schwarz) Y Y Y Y Y	Operations (Schwarz) Y Y Y Y Y	Engineering (Grossman) W W W W	Nuclear Oversight (Scace) W W W Training (Hicks) Y W W W
Work Environment Y	Leadership (Miller) Y Y Y Y	Safety Conscious Work Environment (Burns) W W W Y Y				
Organizational Effectiveness Y	Fiscal Accountability (Kacich) W W W W G	Efficiency (Kacich) R R R Y R	Nuclear Oversight Assessment (Scace) Y Y Y Y Y			
External Relations Y	NRC/NEI Indicators (Schwarz) W W W	INPO Indicators (Schwarz) Y Y Y Y Y	Regulatory Compliance (D.Smith) Y W Y Y Y			

MP Station Performance

Safety	Nuclear Safety (C. Schwarz)	Nuclear Safety Ind. (Safety Culture Index, MP1)	Nuclear Safety Ind. (Safety Culture Index, MP2)	Nuclear Safety Ind. (Safety Culture Index, MP3)			
	Human Performance (C. Schwarz) Y	Condition Report Human Error Rate MP Station Y	Human Performance LERs MP2 Y	Human Performance LERs MP3 G			
	Industrial Safety (D. Horsington) R	Lost Time Accidents	OSHA Recordable Accidents R	INPO Industrial Safety Accident Rate R			
	Radiation Safety (C. Schwarz)	INPO Collective Radiation Exposure MP2 G	INPO Collective Radiation Exposure MP3	% Contaminated RCA Space MP2 G	% Contaminated RCA Space MP3	Personnel Skin Contaminations MP2	Personnel Skin Contaminations MP3 G
	Environmental Performance (P. Jacobson) R	Prompt Environmental Reports Millstone Station R	Environmental Exceedences R	Environmental Process Improvements	Environmental Strategy Implementation Y		
Work Environment	Leadership (D. Miller) Y	Leadership Indicator Y	*Additional Indicators to be developed*				
	Safety Conscious Work Environment (T. Burns) Y	NRC Allegations Received Millstone Station Y	Employee Concerns Confidentiality Trend, Millstone Station G	Employee Concern Investigation Timeliness G	Concerns Involving Potential Violations of 10CFR50.7 R		
Organizational Effectiveness	Fiscal Accountability (R. Kacich) G	Going Forward Cost Millstone Station G	O&M Expenditures Millstone Station G	Capital Expenditures Millstone Station G			
	Efficiency (R. Kacich) R	Staffing Level, Millstone Station (FTEs) R	Contractor Staffing, Millstone Station (as % of total staff) R	Overtime, Millstone Station R	Contract Management Invoice Mismatches Millstone Station R	Nuclear Training Scheduling Efficiency	
		Inventory Level Millstone Station	Delivery On Time Millstone Station	Fill Rate Millstone Station Y	Expediting Costs Millstone Station R	*Additional Indicators to be developed*	
	Nuclear Oversight Assessment (S. Scace) Y	NOVP Nuclear Operations Y	NOVP Engineering Services Y	NOVP Site Services Y	NOVP Human Services Y	NOVP Management Effectiveness & Oversight Y	OE Usage Millstone Station Y

MP Station Performance

Operational Excellence

Work Planning and Outage Management Y (S. Brinkman)	Schedule Adherence - Work Activities, MP2 R	Schedule Adherence - Work Activities, MP3	Schedule Adherence - Surveillances, MP2	Schedule Adherence Surveillances, MP3	*Additional Indicators to be developed*	
	Emergent Work, MP2 R	Emergent Work, MP3	Refueling Outage Milestone Achievement, MP2 Y	Refueling Outage Milestone Achievement, MP3 (NA)		
Maintenance Y (A. Jordan)	On-Line Work Order Status, MP2	On-Line Work Order Status, MP3	% Rework, MP2 (to be developed)	% Rework, MP3 (to be developed)	Overdue Preventive Maintenance Work Orders, MP2 R	[illegible] R
Management Y (C. Schwarz)	Condition Report Procedure Compliance, MP2/MP3/MPSite	Condition Report Evaluation Timeliness, MP2/MP3/MP Site Y	Condition Report Evaluation Quality Score, MP2/MP3/MP Site	Overdue Corrective Actions, MP2/MP3/MP Site		
	Condition Report Method of Discovery, MP2/MP3/MPSite	Open Corrective Actions to Prevent Recurrence - MP2/MP3 R				
	SERO Staffing - % of Full Staff, Millstone Station (to be developed)	Backlog Management - Total Backlog MP2	Backlog Management - Total Backlog MP3			
Operations Y (C. Schwarz)	Reactivity Management Condition Reports, MP2 Y	Reactivity Management Condition Reports, MP3 G	Safety System Actuations, MP2	Emergency System Actuations, MP3	INPO Unplanned Reactor Trips/7000 Critical Hours, MP2 G	INPO Unplanned Reactor Trips/7000 Critical Hours, MP3 Y
	Aggregate Impact, MP2	Aggregate Impact, MP3	INPO Performance Index/Operational Index, MP2	INPO Performance Index/Operational Index, MP3 Y	Operating Capacity Factor/Net Generation, MP2	Capacity Factor/Net Generation, MP3 G
	Reactor Coolant System Identified Leak Rate, MP2 G	Reactor Coolant System Identified Leak Rate, MP3 G	Safety System Unavailability (Maintenance Rule) MP2 R	Safety System Unavailability (Maintenance Rule) MP3 R	Forced Outage Rate, MP2 Y	Forced Outage Rate, MP3 G
	INPO Chemistry Indicator, MP2 G	INPO Chemistry Indicator, MP3 R	INPO Fuel Reliability, MP2 G	INPO Fuel Reliability, MP3 G	INPO Thermal Performance, MP2 G	INPO Thermal Performance MP3 G
	Rad Waste Generation Volume, MP2 G	Rad Waste Generation Volume, MP3 G	Radwaste Liquid Effluent, MP2 R	Radwaste Liquid Effluent, MP3 R		
Engineering (P. Grossman)	Engineering Product Quality, MP2/MP3	10CFR50.65(A)(1) (Mntc Rule) Action Plan Status, MP2	10CFR50.65(A)(1) (Mntc Rule) Action Plan Status, MP3	Configuration Management Summary - CM Related CRs, MP2/MP3 G	Supplemental DCNs, MP2/MP3	
Nuclear Oversight (S. Scace)	Oversight Audit Schedule Performance	Oversight Surveillance Schedule Performance	External Oversight & In-House Events Millstone Station			
Training (D. Hicks)	Training Programs	Line Management Support of Training G	Operator Training Performance			

Y

MP Station Performance

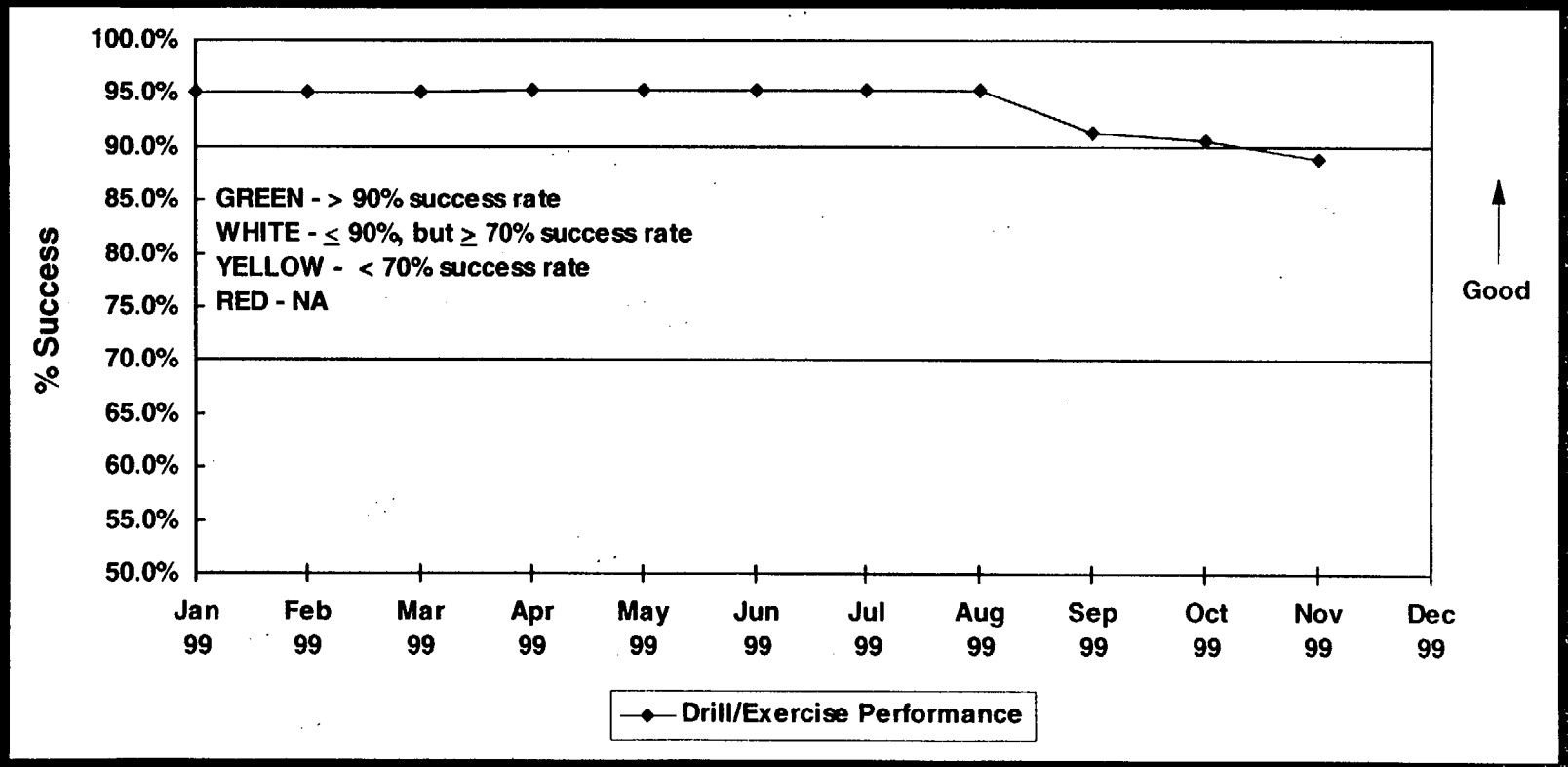
External Relations							
	NRC/NEI Indicators (C. Schwarz)	Unplanned Scrams/7000 Critical Hrs., MP2 G	Unplanned Scrams/7000 Critical Hrs., MP3 G	Scrams With a Loss of Normal Heat Removal, MP2 G	Scrams With a Loss of Normal Heat Removal, MP3 G	Unplanned Pwr. Changes/7000 Critical Hrs., MP2 G	Unplanned Pwr. Changes/7000 Critical Hrs., MP3 G
		Safety System Functional Failures, MP2 G	Safety System Functional Failures, MP3 G	Safety System Unavailability (SSU) Emergency Power, MP2 G	Safety System Unavailability (SSU) Emergency Power, MP3 G	Safety System Unavailability (SSU) HPSI, MP2 G	Safety System Unavailability (SSU) HPSI, MP3 G
		Safety System Unavailability (SSU) RHR, MP2 G	Safety System Unavailability (SSU) RHR, MP3 G	Safety System Unavailability (SSU) AFW, MP2 G	Safety System Unavailability (SSU) AFW, MP3 G	RCS Specific Activity, MP2 G	RCS Specific Activity, MP3 G
		Reactor Coolant System Identified Leak Rate, MP2 G	Reactor Coolant System Identified Leak Rate, MP3 G	Containment Leakage, MP2 G	Containment Leakage, MP3 G	RETS/ODCM Radiological Effluent Occurrence, MP2 G	RETS/ODCM Radiological Effluent Occurrence, MP3 G
		Occupational Exposure Control Effectiveness, MP2 G	Occupational Exposure Control Effectiveness, MP3 G				
		Emergency Preparedness Drill/Exercise Performance	Emergency Response Organization Drill Participation G	Alert & Notification System Reliability G	Protected Area Security Equipment Performance Index G	Personnel Screening Program Performance G	FFD/Personnel Reliability Program Performance G
	INPO Indicators Y (C. Schwarz)	INPO Performance Indicator Index, MP2 R	INPO Performance Indicator Index, MP3 R	INPO Collective Radiation Exposure, MP2 G	INPO Collective Radiation Exposure, MP3	INPO Industrial Safety Accident Rate, MP2 R	INPO Industrial Safety Accident Rate, MP3 G
		INPO Unit Capability Factor, MP2	INPO Unit Capability Factor, MP3	INPO Unplanned Capability Loss Factor, MP2 Y	INPO Unplanned Capability Loss Factor, MP3 Y	INPO Thermal Performance, MP2 G	INPO Thermal Performance, MP3 G
		INPO Unplanned Auto. Scrams per 7000 Hours Critical, MP2 G	INPO Unplanned Auto. Scrams per 7000 Hours Critical, MP3 Y	INPO Fuel Reliability, MP2 G	INPO Fuel Reliability, MP3 G	INPO Safety System Performance - Emer AC Power, MP2	INPO Safety System Performance - Emer AC Power, MP3
		INPO Safety System Performance - HPSI, MP2	INPO Safety System Performance - HPSI, MP3	INPO Safety System Performance - AFW, MP2	INPO Safety System Performance - AFW, MP3	INPO Chemistry Indicator, MP2 G	[illegible] R
		INPO Solid Radioactive Waste Volume, MP2 G	INPO Solid Radioactive Waste Volume, MP3 G				
	Regulatory Compliance Y (D.Smith)	Number of Overdue Regulatory Commitments MP2, MP3 G	Open Regulatory Items, MP2 Y	Open Regulatory Items, MP3 Y	NRC Enforcement Actions, MP2	NRC Enforcement Actions, MP3	

Y

NRC Top Level

NRC/NEI Indicators	Unplanned Scrams/7000 Critical Hrs., MP2 G	Unplanned Scrams/7000 Critical Hrs., MP3 G	Scrams With a Loss of Normal Heat Removal, MP2 G	Scrams With a Loss of Normal Heat Removal, MP3 G	Unplanned Pwr. Changes/7000 Critical Hrs., MP2 G	Unplanned Pwr. Changes/7000 Critical Hrs., MP3 G
	Safety System Functional Failures, MP2 G	Safety System Functional Failures, MP3 G	Safety System Unavailability (SSU) Emergency Power, MP2 G	Safety System Unavailability (SSU) Emergency Power, MP3 G	Safety System Unavailability (SSU) HPSI, MP2 G	Safety System Unavailability (SSU) HPSI, MP3 G
	Safety System Unavailability (SSU) RHR, MP2 G	Safety System Unavailability (SSU) RHR, MP3 G	Safety System Unavailability (SSU) AFW, MP2 G	Safety System Unavailability (SSU) AFW, MP3 G	RCS Specific Activity, MP2 G	RCS Specific Activity, MP3 G
	Reactor Coolant System Identified Leak Rate, MP2 G	Reactor Coolant System Identified Leak Rate, MP3 G	Containment Leakage, MP2 G	Containment Leakage, MP3 G	RETS/ODCM Radiological Effluent Occurrence, MP2 G	RETS/ODCM Radiological Effluent Occurrence, MP3 G
	Occupational Exposure Control Effectiveness, MP2 G	Occupational Exposure Control Effectiveness, MP3 G				
(C. Schwarz)	Emergency Preparedness Drill/Exercise Performance	Emergency Response Organization Drill Participation G	Alert & Notification System Reliability G	Protected Area Security Equipment Performance Index G	Personnel Screening Program Performance G	FFD/Personnel Reliability Program Performance G

E - Plan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% Success
GREEN - > 90% success rate
WHITE - ≤ 90%, but ≥ 70% success rate
YELLOW - < 70% success rate
RED - NA
Good
Jan 99
Feb 99
Mar 99
Apr 99
May 99
Jun 99
Jul 99
Aug 99
Sep 99
Oct 99
Nov 99
Dec 99
Drill/Exercise Performance

Emergency Preparedness

John Carlin
Vice President - Human Services

Millstone has Maintained a Comprehensive Emergency Planning Program

- Station Emergency Response Organization Staffing
  - Maintain a four team rotation
- Training
  - Computer Based Training i.e., Overview
  - Classroom i.e., EALs, dose assessment, PARs
  - Facility Walk-Through
- Drills/Exercises
  - Conducted six successful drills in 1999
  - Corrective actions ongoing for the Fall 1999 drill
  - One additional drill scheduled for 1999

Emergency Preparedness Performance Indicators

- Drill/Exercise Performance
  - –PI status on 12/1/99 was WHITE
  - –Used PI to self identify needed corrective actions
    - •Management focus & support
    - •Additional training and drills conducted
  - –Current status - GREEN
- Drill Participation
  - –Current status - GREEN
- Alert and Notification System Reliability
  - –Current status - GREEN

Millstone Is Committed to Continuous Improvement in Emergency Preparedness

- Station Emergency Response Organization Staffing
  - Maintain four team rotation
  - Continually evaluate performance
  - Realignment of SERO with normal station organization
- Exercise 2000
  - Objectives have been submitted
  - Scenario development is underway
  - NRC Regional Response Team will participate
- Training
  - Training drills are being scheduled for 2000
  - Two drills scheduled per team
  - SERO teams will be used to control drills

Plant Status

Mike Brothers
Vice President - Operations

MP2 Challenges

- 2R13 Preparation
- Work Control

MP3 Challenges

- CPI

Backlog Reduction

Mike Brothers
Vice President - Operations

MP2 Backlog Status

	5/99	09/99	11/99
♦ Corrective Action Assignments	2620	1991	1791
♦ Corrective Maintenance AWOs	502	100	83
♦ Temporary Modifications	10	8	6
♦ Operator Work Arounds	12	9	8
♦ Control Room Deficiencies	24	7	4
♦ Non Conformance Reports	0	0	0
♦ Configuration Mgmnt Discovery	128	99	97
♦ Engineering Backlog	644	474	757
♦ ICAVP DR Corrective Actions	638	583	517
♦ Operability Determinations	18	14	12
	4596	3285	3275

MP3 Backlog Status

	6/98	09/99	11/99
♦ Corrective Action Assignments	3915	1090	971
♦ Corrective Maintenance AWOs	583	72	62
♦ Temporary Modifications	15	7	7
♦ Operator Work Arounds	15	4	4
♦ Control Room Deficiencies	5	0	0
♦ Non Conformance Reports	57	20	20
♦ Configuration Mgmnt Discovery	864	243	184
♦ Engineering Backlog	587	344	311
♦ ICAVP DR Corrective Actions	838	238	131
♦ Operability Determinations	28	8	8
	6907	2026	1698

Safety Conscious Work Environment Update

John Carlin
Vice President - Human Services

Millstone is Sustaining a Safety Conscious Work Environment

- Employees willingly raise concerns in an open and respectful environment
- Management continues to build trust and open work environments - supported by training and assimilations

Resources are Available to Nurture and Improve the SCWE

- Corrective Action Program
- Human Resources
- SCWE Group
- Employee Concerns Program
- ECOP
- People Team

We Continue to Internally Monitor and Assess the Environment

- Monthly ECP Reports
- Quarterly Workplace Surveys
- SCWE Quarterly Assessments
- ECOP Quarterly Reports
- Nuclear Oversight Assessments

LHC Assessments Concluded the SCWE is Being Maintained

- Cautioned about too rapid a return to normalcy
- Improve strategy / communications on people issues
- Improve People Team cooperation / coordination
- Develop a strategy to reduce / eliminate "extraordinary measures"

NRC 40001 Evaluation Concluded a Healthy SCWE Exists

- Overall improvement noted
- Employees willing to raise safety concerns
- SCWE, ECP, ECOP departments remain effective
- Employees familiar with program and processes for handling concerns

We Continue to Monitor our Performance as We Progress Towards a More Ordinary Work Environment

- New Culture Study administered this week
- Third LHC Quarterly Assessment - January 2000
- NRC Inspection - January 2000
- Implement Normalization Strategy
- SCWE Quarterly Assessments
- ECOP Quarterly Reports
- Nuclear Oversight Assessments

Closing Remarks

Mike Brothers

ML03679593

Northeast
Nuclear Energy

Rope Ferry Rd. (Route 156), Waterford, CT 06385

Millstone Nuclear Power Station
Northeast Nuclear Energy Company
P.O. Box 128
Waterford, CT 06385-0128
(860) 447-1791
Fax (860) 444-4277

The Northeast Utilities System

FEB 14 2000

Docket Nos. 50-336
50-423
B17998

Re: 10 CFR 50.71(a)

U.S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555

Millstone Nuclear Power Station, Unit Nos. 2 and 3
Facility Operating License Nos. DPR-65 and NFP-49
Monthly Operating Reports

In accordance with the reporting requirements of Technical Specification 6.9.1.7 for Millstone Unit No. 2, Technical Specification 6.9.1.5 for Millstone Unit No. 3, and Generic Letter 97-02[1], enclosed, are the monthly operating reports for the month of January 2000. Attachment 1, contains the Millstone Unit No. 2 monthly operating report and Attachment 2, contains the Millstone Unit No. 3 monthly operating report.

There are no regulatory commitments contained within this letter.

Should you have any questions regarding this submittal, please contact Mr. Ravi G. Joshi at (860) 447-1791, extension 2080.

Very truly yours,

NORTHEAST NUCLEAR ENERGY COMPANY

FOR: C. J. Schwarz
Station Director

BY: _____
Douglas S. McCracken
Assistant Station Director - Safety

A/9

cc: See next page

[1] NRC Generic Letter 97-02, "Revised Contents of The Monthly Operating Report," May 15, 1997.

Attachments (2)

cc: H. J. Miller, Region I Administrator
J. I. Zimmerman, NRC Project Manager, Millstone Unit No. 2
D. P. Beaulieu, Senior Resident Inspector, Millstone Unit No. 2
V. Nerses, NRC Senior Project Manager, Millstone Unit No. 3
A. C. Cerne, Senior Resident Inspector, Millstone Unit No. 3

Docket Nos. 50-336
50-423
B17998

Attachment 1

Millstone Nuclear Power Station, Unit No. 2

Facility Operating License No. DPR-65
Monthly Operating Report
January 2000

February 2000

AVERAGE DAILY UNIT POWER LEVEL

DOCKET NO: 50-336
UNIT: Millstone Unit 2
DATE: 02/02/00
COMPLETED BY: S. Stark
TELEPHONE: (860) 447-1791
EXT: 4419

MONTH: January 2000

DAY	AVG. DAILY POWER LEVEL (MWe-Net)	DAY	AVG. DAILY POWER LEVEL (MWe-Net)
1	872	17	875
2	872	18	874
3	872	19	874
4	872	20	875
5	871	21	874
6	871	22	850
7	872	23	874
8	872	24	874
9	872	25	874
10	872	26	874
11	872	27	514
12	871	28	0
13	872	29	0
14	875	30	298
15	876	31	739
16	876		

INSTRUCTIONS

On this format, list the average daily unit power level in MWe-Net for each day in the reporting month. Compute to the nearest whole megawatt.

OPERATING DATA REPORT

UNIT NAME: Millstone Unit 2
DATE: 02/03/00
COMPLETED BY: S. Stark
TELEPHONE: (860) 447-1791
EXT: 4419

OPERATING STATUS

1. Docket Number 50-336
2. Reporting Period January 2000
3. Utility Contact S. Stark
4. Licensed Thermal Power (MWt): 2700
5. Nameplate Rating (Gross MWe): 909
6. Design Electrical Rating (Net MWe): 870
7. Maximum Dependable Capacity (Gross MWe): 901.63
8. Maximum Dependable Capacity (Net MWe): 870.63
9. If Changes Occur in Capacity Ratings (Items Number 4 Through 8) Since Last Report, Give Reasons: N/A
10. Power Level To Which Restricted, If any (Net MWe): N/A
11. Reasons For Restrictions, If Any: N/A

Notes: Items 22 and 23 cumulative are weighted averages. Unit operated at 2560 MWTH prior to its uprating to its current 2700 MWTH power level.

	This Month	Yr.-To-Date	Cumulative
12. Hours In Reporting Period	744.0	744.0	211272.0
13. Number Of Hours Reactor Was Critical	704.2	704.2	128061.8
14. Reactor Reserve Shutdown Hours	0.0	0.0	2205.5
15. Hours Generator On-Line	682.2	682.2	122605.5
16. Unit Reserve Shutdown Hours	0.0	0.0	468.2
17. Gross Thermal Energy Generated (MWH)	1797091.0	1797091.0	316527967.8
18. Gross Electrical Energy Generated (MWH)	602935.5	602935.5	103922979.5
19. Net Electrical Energy Generated (MWH)	580343.6	580343.6	99591674.7
20. Unit Service Factor	91.7	91.7	58.0
21. Unit Availability Factor	91.7	91.7	58.3
22. Unit Capacity Factor (Using MDC Net)	89.6	89.6	54.9
23. Unit Capacity Factor (Using DER Net)	89.7	89.7	54.3
24. Unit Forced Outage Rate	8.3	8.3	28.5

25. Shutdowns Scheduled Over Next 6 Months (Type, Date, and Duration of Each):
Unit 2 Refueling Outage 13 is scheduled to commence on April 22, 2000 and is anticipated to last 45 days.
26. If Unit Shutdown At End Of Report Period, Estimated Date of Startup:
27. Units In Test Status (Prior to Commercial Operation):

	Forecast	Achieved
INITIAL CRITICALITY	N/A	N/A
INITIAL ELECTRICITY	N/A	N/A
COMMERCIAL OPERATION	N/A	N/A

UNIT SHUTDOWNS AND POWER REDUCTIONS

DOCKET NO: 50-336
UNIT NAME: Millstone Unit 2
DATE: 02/02/00
COMPLETED BY: S. Stark
TELEPHONE: (860) 447-1791
EXT: 4419

REPORT MONTH: January 2000

No.	Date	Type[1]	Duration (Hours)	Reason[2]	Method of Shutting Down Reactor[3]	License Event Report #	System Code[4]	Component Code[5]	Cause & Corrective Action to Prevent Recurrence
00-01	01/27/00	F	61.8	A	2	00-001-00	SM	PCV	Manual plant trip from 100% power due to a Feedwater Heater Drains System malfunction. Control logic was changed on Heater Drains Tank vent valve to prevent depressurization and flashing of tank contents during certain plant transients.

[1]F: Forced
S: Scheduled

[2]Reason
A - Equipment Failure (Explain)
B - Maintenance or Test
C - Refueling
D - Regulatory Restriction
E - Operator Training & License Examination
F - Administrative
G - Operational Error (Explain)
H - Other (Explain)

[3]Method
1 - Manual
2 - Manual Scram
3 - Automatic Scram
4 - Continued from Previous Month
5 - Power Reduction (Duration = 0)
6 - Other (Explain)

[4]IEEE Standard 805-1984, "Recommended Practices for System Identification in Nuclear Power Plants and Related Facilities"

[5]IEEE Standard 803A-1983, "Recommended Practices for Unique identification in Power Plants and Related Facilities - Component Function Identifiers"

REFUELING INFORMATION REQUEST

1. Name of the facility: Millstone Unit 2

2. Scheduled date for next refueling outage: April 22, 2000

3. Scheduled date for restart following refueling: June 6, 2000 (assuming a 45 day outage)

4. Will refueling or resumption of operation thereafter require a technical specification change or other license amendment?
   One relief request, five technical specification change requests have been identified at this time.

5. Scheduled date(s) for submitting licensing action and supporting information:
   Five technical specification change requests and one relief request have been submitted.

6. Important licensing considerations associated with refueling, e.g., new or different fuel design or supplier, unreviewed design or performance analysis methods, significant changes in fuel design, new operating procedures:
   None at this time

7. The number of fuel assemblies (a) in the core and (b) in the spent fuel storage pool:
   In Core: (a) 217 In Spent Fuel Pool: (b) 868

   NOTE: These numbers represent the total Fuel Assemblies and Consolidated Fuel Storage Boxes (3 total containing the fuel rods from 6 fuel assemblies) in these two (2) Item Control Areas.

8. The present licensed spent fuel pool storage capacity and the size of any increase in licensed storage capacity that has been requested or is planned, in number of fuel assemblies:
   Present licensed storage capacity: 1306 storage locations

9. The projected date of the last refueling that can be discharged to the spent fuel pool assuming present license capacity:
   2003, Spent fuel pool full with core offload (recognizing that there are physical constraints on accessing some of the rack cell locations for fuel assembly storage purposes).
   2008, Spent fuel pool full with discharged reload.

Docket Nos. 50-336
50-423
B17998

Attachment 2

Millstone Nuclear Power Station, Unit No. 3

Facility Operating License No. NPF - 49
Monthly Operating Report
January 2000

February 2000

AVERAGE DAILY UNIT POWER LEVEL

DOCKET NO:	50-423
UNIT:	Millstone Unit 3
DATE:	02/03/00
COMPLETED BY:	K. W. Emmons
TELEPHONE:	(860) 447-1791
EXT:	6572

MONTH: January 2000

DAY	AVG. DAILY POWER LEVEL (MWe-Net)	DAY	AVG. DAILY POWER LEVEL (MWe-Net)
1	1161	17	1160
2	1159	18	1159
3	1160	19	1159
4	1159	20	1159
5	1158	21	1159
6	1159	22	1133
7	1160	23	1158
8	1158	24	1156
9	1159	25	1159
10	1160	26	1158
11	1159	27	1160
12	1157	28	1156
13	1159	29	1158
14	1159	30	1160
15	1160	31	1159
16	1160		

INSTRUCTIONS

On this format, list the average daily unit power level in MWe-Net for each day in the reporting month. Compute to the nearest whole megawatt.

OPERATING DATA REPORT

UNIT NAME: Millstone Unit 3
DATE: 02/03/00
COMPLETED BY: K. W. Emmons
TELEPHONE: (860) 447-1791
EXT: 6572

OPERATING STATUS

1. Docket Number 50-423
2. Reporting Period January 2000
3. Utility Contact K. Emmons
4. Licensed Thermal Power (MWt): 3411
5. Nameplate Rating (Gross MWe): 1253
6. Design Electrical Rating (Net MWe): 1153.6
7. Maximum Dependable Capacity (Gross MWe): 1184.2
8. Maximum Dependable Capacity (Net MWe): 1154.0
9. If Changes Occur in Capacity Ratings (Items Number 4 Through 8) Since Last Report, Give Reasons: Net MDC changed due to Audit NX-12
10. Power Level To Which Restricted, If any (Net MWe): N/A
11. Reasons For Restrictions, If Any: N/A

	This Month	Yr.-To-Date	Cumulative
12. Hours In Reporting Period	744.0	744.0	120,768.0
13. Number Of Hours Reactor Was Critical	744.0	744.0	78,893.0
14. Reactor Reserve Shutdown Hours	0.0	0.0	6,565.0
15. Hours Generator On-Line	744.0	744.0	77,389.5
16. Unit Reserve Shutdown Hours	0.0	0.0	0.0
17. Gross Thermal Energy Generated (MWH)	2,534,887.0	2,534,887.0	254,519,300.1
18. Gross Electrical Energy Generated (MWH)	896,962.5	896,962.5	88,011,683.1
19. Net Electrical Energy Generated (MWH)	861,565.0	861,565.0	83,661,449.4
20. Unit Service Factor	100.0	100.0	64.1
21. Unit Availability Factor	100.0	100.0	64.1
22. Unit Capacity Factor (Using MDC Net)	100.3	100.3	60.8
23. Unit Capacity Factor (Using DER Net)	100.4	100.4	60.1
24. Unit Forced Outage Rate	0.0	0.0	28.6
25. Unit Forced Outage Hours	0.0	0.0	31,055.7

26. Shutdowns Scheduled Over Next 6 Months (Type, Date, and Duration of Each): N/A
27. If Unit Shutdown At End Of Report Period, Estimated Date of Startup: N/A
28. Units In Test Status (Prior to Commercial Operation):

	Forecast	Achieved
INITIAL CRITICALITY	N/A	N/A
INITIAL ELECTRICITY	N/A	N/A
COMMERCIAL OPERATION	N/A	N/A

UNIT SHUTDOWNS AND POWER REDUCTIONS

DOCKET NO: 50-423
UNIT NAME: Millstone Unit 3
DATE: 02/03/00
COMPLETED BY: K. W. Emmons
TELEPHONE: (860) 447-1791
EXT: 6572

REPORT MONTH: January 2000

No.	Date	Type[1]	Duration (Hours)	Reason[2]	Method of Shutting Down Reactor[3]	License Event Report #	System Code[4]	Component Code[5]	Cause & Corrective Action to Prevent Recurrence
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

[1]F: Forced
S: Scheduled

[2]Reason
A - Equipment Failure (Explain)
B - Maintenance or Test
C - Refueling
D - Regulatory Restriction
E - Operator Training & License Examination
F - Administrative
G - Operational Error (Explain)
H - Other (Explain)

[3]Method
1 - Manual
2 - Manual Scram
3 - Automatic Scram
4 - Continued from Previous Month
5 - Power Reduction (Duration = 0)
6 - Other (Explain)

[4]IEEE Standard 805-1984, "Recommended Practices for System Identification in Nuclear Power Plants and Related Facilities"

[5]IEEE Standard 803A-1983, "Recommended Practices for Unique identification in Power Plants and Related Facilities - Component Function Identifiers"

REFUELING INFORMATION REQUEST

1. Name of the facility: Millstone Unit 3

2. Scheduled date for next refueling outage: February, 2001

3. Scheduled date for restart following refueling: March, 2001

4. Will refueling or resumption of operation thereafter require a technical specification change or other license amendment?
   No

5. Scheduled date(s) for submitting licensing action and supporting information:
   N/A

6. Important licensing considerations associated with refueling, e.g., new or different fuel design or supplier, unreviewed design or performance analysis methods, significant changes in fuel design, new operating procedures:
   None at this time

7. The number of fuel assemblies (a) in the core and (b) in the spent fuel storage pool:
   In Core: (a) 193 In Spent Fuel Pool: (b) 497

8. The present licensed spent fuel pool storage capacity and the size of any increase in licensed storage capacity that has been requested or is planned, in number of fuel assemblies:
   Present storage capacity: 756 storage locations
   Increase in licensed storage capacity planned for total of 1860 locations.

9. The projected date of the last refueling that can be discharged to the spent fuel pool assuming present license capacity:
   2001, Spent fuel pool full with core offload.

Northeast
Nuclear Energy

Rope Ferry Rd. (Route 156), Waterford, CT 06385

Millstone Nuclear Power Station
Northeast Nuclear Energy Company
P.O. Box 128
Waterford, CT 06385-0128
(860) 447-1791
Fax (860) 444-4277

The Northeast Utilities System

FEB 24 2000

Docket No. 50-336
B18002

Re: 10 CFR 50.73(a)(2)(iv)

U.S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555

Millstone Nuclear Power Station, Unit No. 2
Licensee Event Report 2000-001-00
Manual Reactor Trip Due to Secondary System Transient

This letter forwards Licensee Event Report (LER) 2000-001-00, documenting an event that occurred at Millstone Nuclear Power Station, Unit No. 2, on January 27, 2000. This LER is being submitted pursuant to 10 CFR 50.73(a)(2)(iv).

There are no regulatory commitments contained within this letter.

Very truly yours,

NORTHEAST NUCLEAR ENERGY COMPANY

FOR: C. J. Schwarz
Station Director

BY: _____
D. S. McCracken
Assistant Station Director - Safety

Attachment (1): LER 2000-001-00

cc: H. J. Miller, Region I Administrator
J. I. Zimmerman, NRC Project Manager, Millstone Unit No. 2
D. P. Beaulieu, Senior Resident Inspector, Millstone Unit No. 2

A/10

Docket No. 50-336
B18002

Attachment 1

Millstone Nuclear Power Station, Unit No. 2

LER 2000-001-00

February 2000

NRC FORM 366 (6-1998) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 06/30/2001

Estimated burden per response to comply with this mandatory information collection request: 50 hrs. Reported lessons learned are incorporated into the licensing process and fed back to industry. Forward comments regarding burden estimate to the Records Management Branch (T-6 F33), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, and to the Paperwork Reduction Project (3150-0104), Office of Management and Budget, Washington, DC 20503. If an information collection does not display a currently valid OMB control number, the NRC may not conduct or sponsor, and a person is not required to respond to, the information collection.

LICENSEE EVENT REPORT (LER)

(See reverse for required number of digits/characters for each block)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Millstone Nuclear Power Station Unit 2	05000336	1 OF 6

TITLE (4)

Manual Reactor Trip Due to Secondary System Transient

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
01	27	2000	2000	-- 001 --	00	02	24	2000	FACILITY NAME	DOCKET NUMBER

OPERATING MODE (9)	1	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)							
			20.2201(b)		20.2203(a)(2)(v)		50.73(a)(2)(i)		50.73(a)(2)(viii)
POWER LEVEL (10)	100		20.2203(a)(1)		20.2203(a)(3)(i)		50.73(a)(2)(ii)		50.73(a)(2)(x)
			20.2203(a)(2)(i)		20.2203(a)(3)(ii)		50.73(a)(2)(iii)		73.71
			20.2203(a)(2)(ii)		20.2203(a)(4)	X	50.73(a)(2)(iv)		OTHER
			20.2203(a)(2)(iii)		50.36(c)(1)		50.73(a)(2)(v)		Specify in Abstract below or in NRC Form 366A
			20.2203(a)(2)(iv)		50.36(c)(2)		50.73(a)(2)(vii)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
R. Joshi, MP2 Acting Regulatory Compliance Supervisor	(860) 440-2080

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX

SUPPLEMENTAL REPORT EXPECTED (14)				EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
	YES (If yes, complete EXPECTED SUBMISSION DATE).	X	NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines) (16)

On January 27, 2000 at approximately 1427 hours with the unit in Mode 1 at 100 percent power, a manual reactor trip was initiated due to a rapid decrease in the "B" Steam Generator (SG) level to approximately 57 percent and the trip of a SG feedwater pump. The plant response was uncomplicated with safety systems performing as expected. The plant was stabilized at normal post trip parameters (Mode 3) and operating shift personnel reacted appropriately. Operators manually initiated the auxiliary feedwater system to restore SG water levels.

It was determined that this event was caused by the loss of all heater drain flow to the suction of the SG feedwater pumps as a result of bulk flashing in the heater drain tank. As event precursors, it was determined that the transient was initiated due to the restoration of the 2A feedwater heater's sight glass causing oscillations in the feedwater control system that adversely affected the systems' ability to recover from the transient. Also, it was concluded that the heater drain tank vent control valve 2-HD-104 control logic wiring did not permit the valve to function properly in order to mitigate the consequences of a loss or rapid reduction of extraction steam pressure on the heater drain tank.

Completed corrective actions include optimizing the feedwater heater system performance by improving the stroke time for the level controller valve, and correcting the control logic for 2-HD-104 such that the valve will close to prevent depressurization of the heater drain tank.

FACILITY NAME (1)	DOCKET	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Millstone Nuclear Power Station Unit 2	05000336	2000	-- 001 --	00	2 OF 6

TEXT *(If more space is required, use additional copies of NRC Form 366A)* (17)

I. Description of Event

On January 27, 2000 at approximately 1427 hours with the unit in Mode 1 at 100 percent power, a manual reactor [RCT] trip was initiated due to a rapid decrease in the "B" Steam Generator (SG) level to approximately 57 percent and the trip of a SG feedwater pump (SGFP) [P]. The plant response was uncomplicated with safety systems performing as expected. The plant was stabilized at normal post trip parameters (Mode 3) and operating shift personnel reacted appropriately. Operators manually initiated the auxiliary feedwater system [BA] to restore SG water levels.

After post-trip analysis, it was determined that the transient was initiated following a leak repair and restoration of the 2A feedwater heater [HX] sight glass [LG] (see figures 1 and 2 for simplified arrangement sketches of the heater drain system [SM] and sight glass/level sensor). This action combined with a slow actuation of the 2A feedwater heater level control valve [LCV] 2-HD-103C, exacerbated the severity of the transient, resulting in a large volume of relatively hot water entering the heater drain tank [TK]. Heater drain tank pressure increased, stopping or reducing flow from the 3A/B feedwater heaters resulting in high level and automatic extraction steam valve isolation.

With extraction steam isolated to the 3A/B heaters, steam pressure in those heaters decayed approximately 30 psi over a short time period. During this period, the heater drain tank vent valve [VTV] 2-HD-104 to the 3A/B feedwater heaters remained open from the initiation of the transient until the main turbine [TRB] tripped following the reactor trip. This vent valve should have closed upon receipt of either the 3A or 3B heater high level alarm. With the vent valve open and extraction steam isolated, the 3A/B heaters condensed steam from the heater drain tank and caused a rapid depressurization of the tank. Because conditions in this portion of the feedwater heater system are near saturation conditions, the sudden loss of pressure caused the water in the heater drain tank to flash to steam which ultimately resulted in a loss of net positive suction head to the heater drain pumps and loss of heater drain flow to the SGs. Shortly thereafter, SG feed pump suction pressure decreased and resulted in a SGFP trip. As level in the SGs began to decrease, the primary plant was manually tripped.

Because the event resulted in a manual actuation of the reactor protection system, it is being reported pursuant to the requirements of 10CFR50.73(a)(2)(iv).

II. Cause of Event

It was determined that this event was caused by the loss of all heater drain flow to the suction of the SGFPs as a result of bulk flashing in the heater drain tank. As event precursors, it was determined that the transient was initiated due to the restoration of the 2A feedwater heater's sight glass causing oscillations in the feedwater control system that adversely affected the systems' ability to recover from the transient. Also, it was concluded that the heater drain tank vent control valve 2-HD-104 control logic wiring did not permit the valve to function properly in order to mitigate the consequences of a loss or rapid reduction of extraction steam pressure on the heater drain tank.

III. Analysis of Event

The feedwater heater drain system is a non-safety related system which is not required to safely shutdown the plant or mitigate the consequences of an accident. However, this system is necessary for operation at 100 percent power since it provides approximately 30 percent of feedwater flow to the steam generators. In this event, the plant was not able to recover from the initiating transient which ultimately resulted in a total loss of feedwater

heater drain flow. The plant was manually tripped. There were no challenges to the primary plant response and all safety systems responded as expected. As a result, this event is classified as being of low safety significance.

IV. Corrective Action

As a result of this event, the following actions have been performed:

1. The feedwater heater system performance was optimized by improving the stroke time for the level controller valve.
2. The control logic for 2-HD-104 has been corrected such that the valve will close to prevent depressurization of the heater drain tank.

In addition, other corrective actions to improve the feedwater heater drains system performance are being addressed via the Millstone Corrective Action Program.

V. Additional Information

Similar Events

The following similar events relate to past feedwater heater system trips. Although each involved the feedwater heater drains system, no clear lines could be drawn to show that the corrective actions from these past events would have precluded this present event.

LER 99-009: "Manual Reactor Trip Due to Steam Leak in Turbine Building"

Reported a manual reactor trip as a result of secondary plant anomaly. In this instance, a steam leak in the turbine building occurred following erratic feedwater heater level response. The cause of the event was determined to be inadequate controls associated with the adjustment and grooming of the feedwater heater level control valves which resulted in an overpressure condition when the shell side relief valve lifted. Corrective actions included refining of controls for adjusting feedwater heater string controls and clarifying guidance for torqued connections when significant dynamic piping loads are expected.

LER 95-032: "Manual Reactor Trip Due to Unisolable Secondary Steam Leakage"

Reported a manual trip as a result of a steam leak in a secondary system within the turbine building. The leak was caused by a 14 inch vertical rupture in the 8 inch diameter recirculation line from the discharge of the "B" heater drain pump to the heater drain tank. The root cause of the rupture was attributed to water hammer on an already degraded section of piping that resulting in the piping exceeding its burst pressure. Corrective actions primarily involved, equipment damage and erosion/corrosion inspections, and a design review of the heater drains system to verify adequacy for all operational conditions.

FACILITY NAME (1)	DOCKET	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Millstone Nuclear Power Station Unit 2	05000336	2000	-- 001 --	00	4 OF 6

TEXT *(If more space is required, use additional copies of NRC Form 366A)* **(17)**

LER 86-006: "Auto Rx Trip on Low Steam Generator Level Resulting from Loss of Heater Drains Flow"

Reported an automatic plant trip on low steam generator level as a result of a loss of heater drains flow. The loss of flow was due to the closure of level control valve 2-HD-109 located downstream of the combined discharge of both heater drains pumps. The valve closure was the result of a failed fitting connection on the supply to the controller's signal air regulator. The cause of this event was attributed to cyclic vibration stresses compounded by the possibility that the original installation of the tubing may have overstressed the fitting connection. Corrective actions involved parts replacement and upgrading the support of the affected valve. Other plant valves with similar controllers were inspected and modified to provide adequate support.

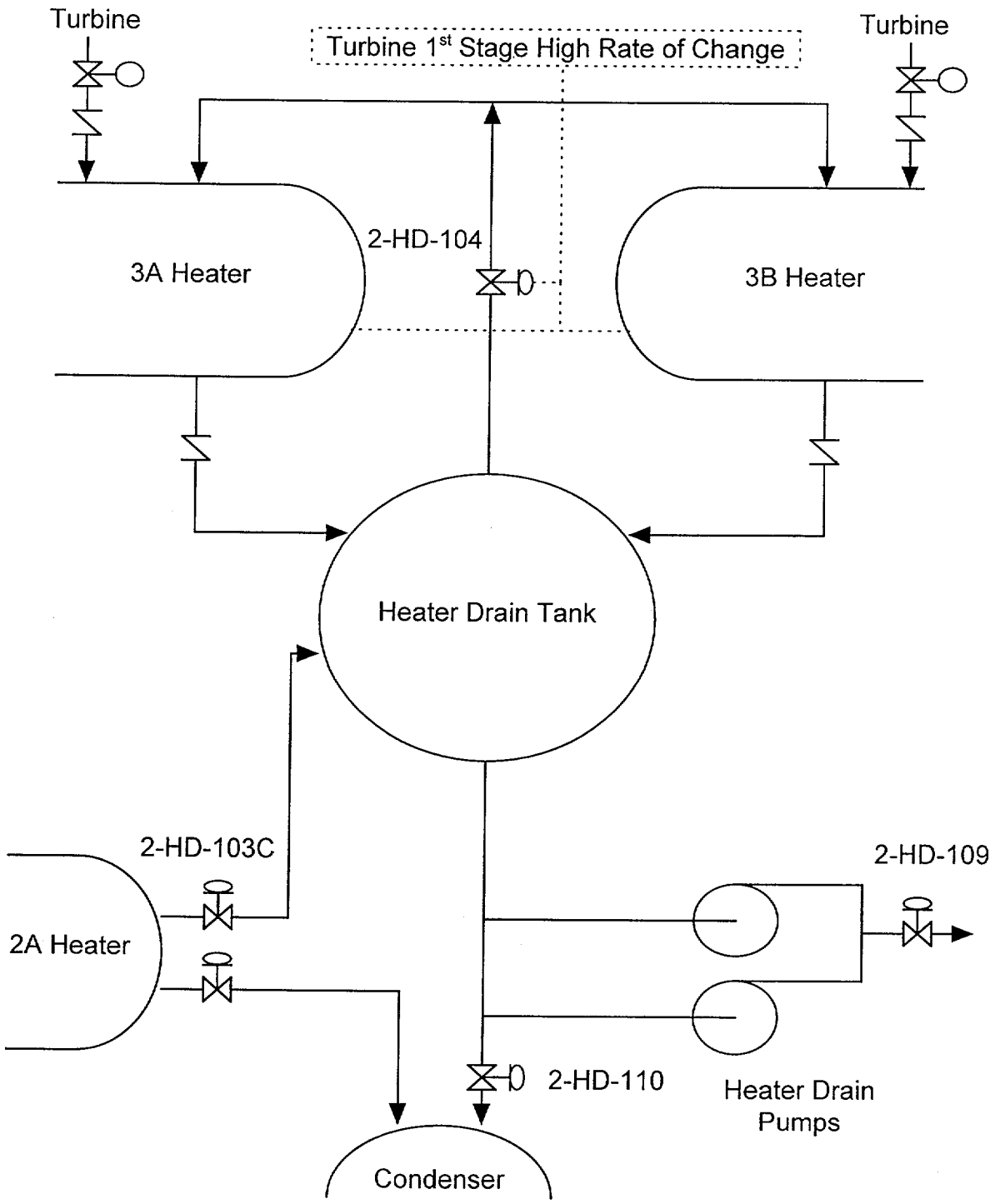
Energy Industry Identification System (EIIS) codes are identified in the text as [XX].

FACILITY NAME (1)	DOCKET	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Millstone Nuclear Power Station Unit 2	05000336	2000	-- 001 --	00	5 OF 6

TEXT *(If more space is required, use additional copies of NRC Form 366A)* **(17)**

Figure 1

"Simplified Heater Drain System Sketch"



FACILITY NAME (1)	DOCKET	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
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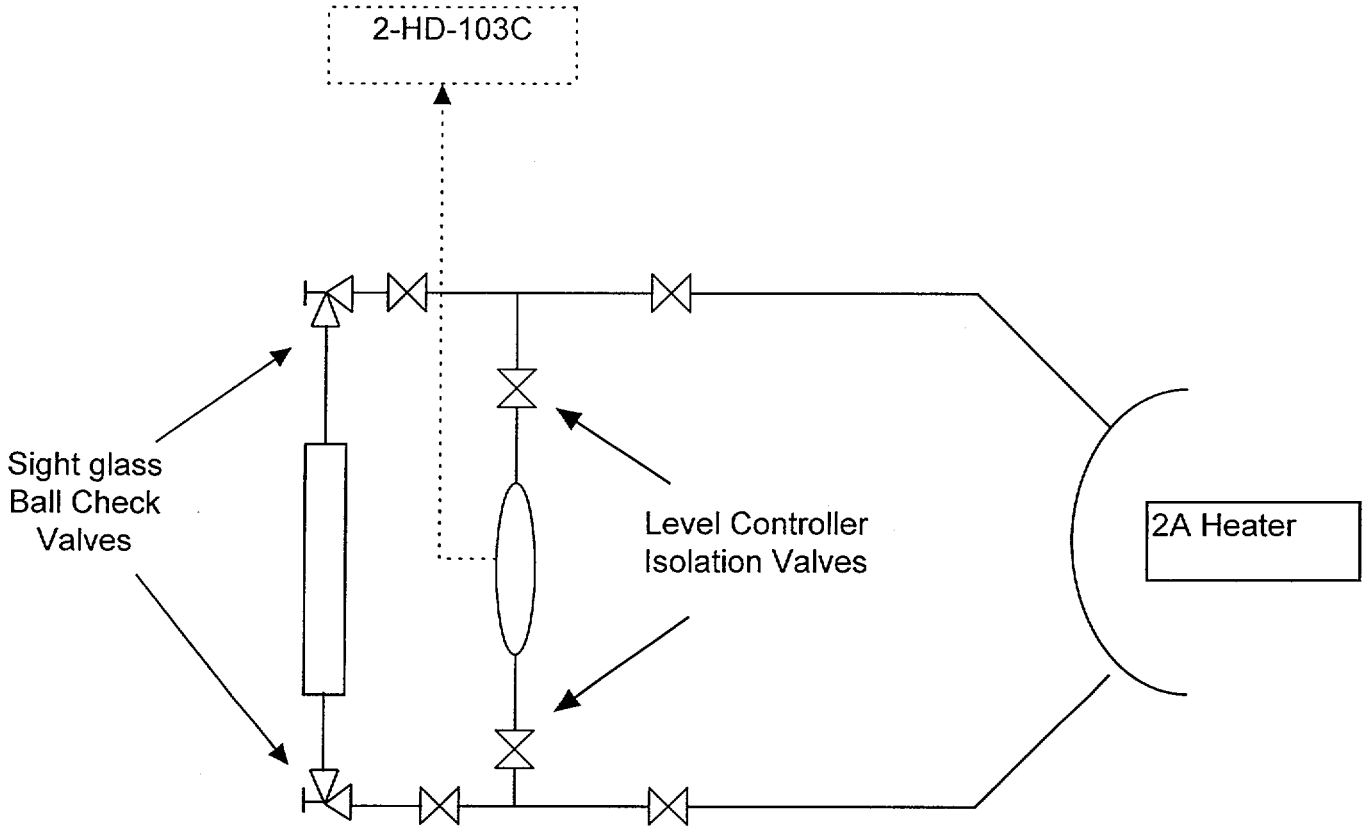
TEXT *(If more space is required, use additional copies of NRC Form 366A)* (17)

Figure 2

"Heater Sight Glass / Level Sensor Arrangement"



REGION I
PLANT PERFORMANCE REVIEW

FACILITY: Millstone Unit 2

I. PERFORMANCE OVERVIEW
- Operating History
- Current Overall Assessment
- Previous Assessment Results

II. STRATEGIC AREA ASSESSMENTS
- Assessment
- Basis
- Inspection Program Recommendations

III. ATTACHMENTS
- Plant Issues Matrix
- Draft PPR Letter with Inspection Plan
- Power History Charts
- Plant Strategy
- Performance Indicators
- Previous PPR letters
- Open Item Assessment

PPR Updated: February 24, 2000

Approval: for
James C. Linville, Director
Millstone Inspection Directorate

The attached report has not been made public.
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Treat as "OFFICIAL USE ONLY".

A/11

PRE-DECISIONAL
PLANT PERFORMANCE REVIEW - ANNUAL ASSESSMENT
MILLSTONE NUCLEAR POWER STATION
UNIT 2

Current Assessment Period: January 16, 1999 to January 31, 2000

I. Performance Overview

Operating History

On May 9, 1999, Millstone Unit 2 resumed operation at power following an extended shutdown of over three years in length. During the assessment period, the plant experienced two manual reactor trips (May 25, 1999, and January 27, 2000) caused by secondary system equipment problems. Also, one forced shutdown on September 17, 1999, was caused by an unrecoverable, misaligned control rod. [Although outside the PPR assessment period, the reactor was manually tripped on February 11, 2000, due to two dropped control rods; one the controls rods was the misaligned rod that necessitated the September 17, 1999, shutdown.]

Current Overall Assessment

While emergent equipment problems have resulted in two plant trips and a plant shutdown, Millstone Unit 2 completed two four-month periods of continuous operation since the startup from May 1999. Operators responded well to emergent equipment problems and displayed a conservative approach to plant operations. In particular, the operators responded well to a dropped control rod in September 1999, when they were simultaneously responding to numerous circulating water temperature alarms. Also, operators promptly inserted a manual reactor trip when a steam leak occurred in the turbine building in May 1999.

While many equipment problems were identified and corrected during the extended outage, some longstanding and recurrent issues continue to challenge operators. Several instances were identified where engineering resolutions of these equipment problems were ineffective resulting in degraded or inoperable safety equipment and two feedwater system transients that led to manual reactor trips. An example included recurrent high resistance contacts in a reactor protection system switch that caused one channel to be inoperable. In some instances, equipment obsolescence has hampered the ability to effectively resolve problems, particularly with electronic equipment such as reactor protection system and rod control system components.

The licensee placed appropriate focus on addressing the backlog and has appropriately prioritized and scheduled work items. However, large engineering and corrective action backlogs for Unit 2 and the competition for resources between emerging work and existing item closeout activities present a continuing challenge to the licensee.

Although the corrective action process continues to be characterized by a low-threshold and a high volume, the NRC identified several examples where the licensee failed to initiate condition reports for safety systems that were significantly degraded. An example

included the failure to initiate a condition report for a problem with water intrusion into the bearing lube oil of an auxiliary feed water pump. Also, the licensee did not initiate a condition report when air entrapment in the piping to the containment sump had the potential to render a train of high pressure coolant injection and containment spray inoperable. Notwithstanding, the problem with condition report initiation was not determined to be pervasive.

A generally healthy safety conscious work environment existed at Millstone. Both Little Harbor Consultants and the NRC noted improvement during the assessment period. The licensee had appropriate programs and processes established to address employee concerns and to monitor and evaluate the safety conscious work environment. Although some deficiencies were found, they did not detract from the overall effectiveness of the programs and processes. Site employees were familiar with programs and processes for handling concerns, and they would be willing to raise nuclear safety concerns. Challenges to a safety conscious work environment remained due to the ongoing supervisor cascade, the contracting of Entergy to manage the decommissioning of Unit 1, planned reductions in contractor and licensee positions and consideration of a revised pay structure.

Also in the reactor safety area, emergency preparedness were effectively implemented. In the radiation safety and safeguards areas, the programs were similarly found to have been effectively implemented.

Previous Assessment Results

Millstone Unit 2 was not assessed during the previous PPR cycle because the unit remained in an extended shutdown throughout the period.

II. Strategic Performance Area Assessments

REACTOR SAFETY

A. Reactor Safety Assessment

Weak or inadequate procedures contributed to a number of operational issues including the initiation of a feedwater heater level transient that resulted in a reactor trip and an inadequate surveillance procedure for the atmospheric dump valves which if performed as written could have resulted in a reactor trip. Operators and maintenance technicians were also challenged by numerous equipment problems. Problems with feedwater heater level control led to two reactor trips and rod control system failures resulted in a forced shutdown (and a reactor trip on February 11, 2000, which is outside the assessment period.) In some instances, equipment obsolescence has hampered the ability to effectively resolve problems due to difficulties in obtaining replacement parts, particularly with respect to electronic equipment such as the reactor protection system.

Despite the relatively low level of at-power experience among licensed operators, the operators have performed well in responding to operational challenges caused by the weak procedures and equipment problems. However, a weakness was noted in the reactivity management and oversight when reactor criticality occurred at a higher level than specified in the procedure during a reactor startup. In another instance, operators did not adequately anticipate the effect of xenon during a planned power increase. and one power increase to 100 percent power.

Several instances were identified where engineering resolutions of some long-standing and recurrent equipment problems were ineffective. On two occasions, a significant amount of water accumulated in the bearing oil of the "B" auxiliary feedwater pump, a condition that has recurred many times over the life of the plant. The licensee was also untimely in addressing recurrent instances where a reactor protection system channel was rendered inoperable due to a drifting thermal margin/low pressure setpoint. The improper setup of feedwater heater level control valves caused a plant transient and a subsequent manual reactor trip.

Although many design control and configuration management deficiencies were identified and corrected during the extended outage, some additional examples have been identified post-restart. For example, the NRC found that design control measures were inadequate to assure that the 4160 volt switchgear room coolers were capable of maintaining a suitable environment for the vital switchgear under post-accident conditions.

Although in September 1999, several objectives during the off-year exercise were not met, overall, the emergency preparedness program is being satisfactorily implemented.

B. Reactor Safety-Basis

B1. Weak or inadequate procedures contributed to a number of operational issues.

On January 27, 2000, when operators encountered problems restoring the sight-glass for the 2A main feedwater heater to service, operators cycled one of the sight-glass isolation valves, which was an evolution outside the scope of the operating procedure. The valve manipulation initiated a feedwater heater level transient that was exacerbated by longstanding sluggish operation of the 2A feedwater heater level control system, which had also contributed to a previous reactor trip on May 25, 1999. As a result of an original design problem associated with the heater drain tank, the feedwater heater level transient developed into an unanticipated total loss of heater drain flow, a trip of one main feedwater pump, and a subsequent manual reactor trip based on decreasing steam generator water levels. (01/27/00, 2000001 **DRAFT**)

Operators did not adequately anticipate the effect of xenon during a planned power increase from 84 to 100 percent power. Consequently, this routine power increase was performed in a manner that resulted in the reactor's axial power distribution value

exceeding the limit specified in the operating procedure, the receipt of multiple reactor protection system pre-trip alarms for local power density, and the unplanned need to add multiple batches of concentrated boric acid to restore axial power distribution within the specified limit. The failure to adequately implement the operating procedure to maintain the axial power distribution value within the specified limit is being treated as a Non-Cited Violation. (11/22/1999, 1999012)

The circulating water system operating procedure was weak in that it did not specify the reactor power level to allow securing a circulating water pump. As a result when a circulating water pump was secured at 85% power, numerous main condenser alarms and reduced main condenser vacuum occurred, which unnecessarily challenged plant operators. (10/04/1999, 1999009)

The licensee failed to revise the plant cooldown procedure to reflect a change in reactor protection system (RPS) setpoints in April 1999. As a result, an unplanned RPS actuation on low steam generator level occurred while the plant was shut down. The failure to adequately maintain the plant cooldown procedure is being treated as a Non-Cited Violation. (10/04/1999, 1999009)

During a pre-job brief an operator identified an inadequate surveillance for the atmospheric dump valves which if performed as written could have resulted in a reactor trip. Although it is good that operators are properly addressing these procedural issues as they arise, reliance on individuals performing the procedures to identify procedural deficiencies presents an unnecessary challenge to plant personnel. (06/14/1999, 1999006)

On May 25, 1999, from operation at full power, operators initiated a manual reactor trip at Unit 2 when a steam leak developed in the turbine building as a result of a transient in the feedwater heaters. The feedwater heater transient was caused by improper setup of the feedwater heater level control valves. Inadequate procedural control was identified as the root cause, with inadequate initial design and inadequate corrective actions to address recurring level control problems identified as contributing causes. (06/14/1999, 1999006)

Unit 2 post-fire shutdown procedures, in some instances, contained problems related to sequencing of DC control power actions, and some actions were not well coordinated between the Unit 1 and Unit 2 procedures. (03/26/1999, 1999003)

While in Mode 5, an inadvertent increase in reactor coolant system (RCS) level of approximately 25 inches occurred when the safety injection tank (SIT) outlet motor operated valves (MOVs) were opened to perform testing because operators failed to recognize the potential for a significant quantity of water in the SIT lower head and its injection piping to be present and drain to the RCS. Consequently, the operators did not request a procedure change to provide specific instructions and precautions for opening the valves while in this plant condition. The water that was added had approximately the

same boron concentration as the RCS and water level remained several feet below the lowest open penetration in the reactor vessel head. The NRC concluded that the failure to establish adequate procedural controls for operation of the SIT outlet MOVs constituted a violation of Technical Specification 6.8.1.a. (03/01/1999, 1999002)

The operating procedure that provides instructions for draining the refueling cavity was inadequate in that, at the completion of the draining evolution, the procedure failed to direct the isolation of the flow path to the liquid radioactive waste system. Subsequently, the configuration established through use of this procedure led to the inadvertent loss of approximately 2 inches of spent fuel pool water level when about 2730 gallons of spent fuel pool water was transferred to the liquid radioactive waste system. However, performance of the plant equipment operator was good in promptly identifying and terminating the spent fuel pool water loss. The failure to adequately maintain the operating procedure constituted a violation of Technical Specification 6.8.1. (03/01/1999, 1999002)

Although the testing portion of the integrated test of the Facility 1 engineered safety features components was well executed, the procedure instructions for restoration from the test were inadequately implemented. Steps to restore the "A" charging pump were performed in an inappropriate sequence, which resulted in the inadvertent start of the "A" charging pump. The subsequent injection of approximately 100 gallons of water from the volume control tank to the reactor coolant system (RCS) did not result in a reduction in RCS boron concentration. The NRC concluded that the surveillance procedure was weak in that, it allowed restoration steps to be performed out of sequence when the shift manager determined that the sequence of performance was unimportant and the procedure did not clearly identify restoration steps where the sequence of performance was important. The failure to adequately implement the surveillance procedure constituted a violation of Technical Specification 6.8.1.c. (03/01/1999, 1999002)

B2. A weakness was noted in the reactivity management and oversight during a reactor startup and one power increase to 100 percent power.

Operators did not adequately anticipate the effect of xenon during a planned power increase from 84 to 100 percent power. Consequently, this routine power increase was performed in a manner that resulted in the reactor's axial power distribution value exceeding the limit specified in the operating procedure, the receipt of multiple reactor protection system pre-trip alarms for local power density, and the unplanned need to add multiple batches of concentrated boric acid to restore axial power distribution within the specified limit. The failure to adequately implement the operating procedure to maintain the axial power distribution value within the specified limit, as required by Technical Specification 6.8.1, is being treated as a Non-Cited Violation. (11/22/1999, 1999012)

At Unit 2, the NRC identified that the licensee failed to initiate a condition report to document that, during the reactor startup, reactor criticality occurred at a higher power level than expected which resulted in the recording of critical data at power level that was

higher than power level specified in the procedure. A condition report is necessary to ensure that the cause of the higher power level is evaluated and that corrective actions are taken to prevent recurrence during future reactor startups. The failure to initiate a condition report as required by the corrective action procedure is being treated as a Non-Cited Violation. (10/04/1999, 1999009)

B3. Operators and maintenance technicians were challenged by a number of equipment problems. Equipment obsolescence, particularly with electronic equipment has hampered the ability to effectively resolve problems due to difficulties in obtaining replacement parts.

On January 27, 2000, when operators encountered problems restoring the sight-glass for the 2A main feedwater heater to service, operators cycled one of the sight-glass isolation valves, which was an evolution outside the scope of the operating procedure. The valve manipulation initiated a feedwater heater level transient that was exacerbated by longstanding sluggish operation of the 2A feedwater heater level control system, which had also contributed to a previous reactor trip on May 25, 1999. As a result of an original design problem associated with the heater drain tank, the feedwater heater level transient developed into an unanticipated total loss of heater drain flow, a trip of one main feedwater pump, and a subsequent manual reactor trip based on decreasing steam generator water levels. (01/27/00, 2000001 **DRAFT**)

The licensee's determination of continued operability of the reactor protection system, despite some degradation, was adequately founded. The majority of issues pose only a minimal increase in the probability of an inadvertent reactor trip or a distraction to the control operators and have no effect on the system's safety function. The licensee has implemented or scheduled appropriate measures to address the degraded conditions consistent with their importance to safety. However, the licensee was untimely in developing a plan to address recurrent instances where an RPS channel was rendered inoperable due to a drifting thermal margin/low pressure setpoint. (01/05/2000, 1999014)

At Unit 2, on September 17, 1999, operators appropriately implemented the required actions for a dropped control rod and performed a reactor shutdown in a controlled and deliberate manner. Operator performance was particularly good in that the dropped rod occurred at a time they were responding to numerous main condenser alarms that resulted when the "D" circulating water pump was secured. (10/04/1999, 1999009)

At Unit 2, when a control circuit card failed for the main feedwater regulating bypass valve, reactor operator performance was good in immediately recognizing, before any alarms were received, that the bypass valve had closed. Due to prompt action by the reactor operator to restore main feedwater flow, a plant transient was averted. (10/04/1999, 1999009)

On May 25, 1999, from operation at full power, operators initiated a manual reactor trip at

Unit 2 when a steam leak developed in the turbine building as a result of a transient in the feedwater heaters. Operator performance in isolating the steam leak and placing the plant in a stable condition was good. The feedwater heater transient was caused by improper setup of the feedwater heater level control valves. Inadequate procedural control was identified as the root cause, with inadequate initial design and inadequate corrective actions to address recurring level control problems identified as contributing causes. The transient developed into a steam leak because generic engineering guidance for selecting torque values was improperly applied in the selection of torque values for the feedwater heater relief valve flange fasteners. (06/14/1999, 1999006)

B4. Engineering resolutions of some long-standing and recurrent equipment problems were ineffective.

On January 27, 2000, when operators encountered problems restoring the sight-glass for the 2A main feedwater heater to service, operators cycled one of the sight-glass isolation valves, which was an evolution outside the scope of the operating procedure. The valve manipulation initiated a feedwater heater level transient that was exacerbated by longstanding sluggish operation of the 2A feedwater heater level control system, which had also contributed to a previous reactor trip on May 25, 1999. As a result of an original design problem associated with the heater drain tank, the feedwater heater level transient developed into an unanticipated total loss of heater drain flow, a trip of one main feedwater pump, and a subsequent manual reactor trip based on decreasing steam generator water levels. (01/27/00, 2000001 **DRAFT**)

The licensee failed to recognize that the established performance criteria of no repetitive functional failures for the reactor protection system (RPS) was exceeded on May 28, 1999, and again exceeded in October and November 1999, when another three functional failures occurred. The licensee failed to place the system into an (a)(1) status and establish goals commensurate with safety in violation of 10 CFR 50.65(a)(1). As a result, the licensee was untimely in developing a plan to address recurrent instances where an RPS channel was rendered inoperable due to a drifting thermal margin/low pressure setpoint. (01/05/2000, 1999014)

At Unit 2, the licensee failed to initiate a condition report and implement effective corrective actions when a significant amount of water was identified in the oil removed from the outboard bearing of the "B" auxiliary feed water pump during a scheduled oil change on April 12, 1999. As a result, the condition recurred during continuous operation of the pump from May 25 through 29, 1999, and the degraded condition was not identified and corrected until June 1, 1999. In addition, the licensee's assessment of operability during the period prior to June 1, 1999, was not well founded in that it was based on the ability of the system, rather than the component, to perform its design function. Finally, the licensee inappropriately used the conclusion that the pump had been operable as a basis to reduce the degree of thoroughness in identifying and implementing corrective actions to address the recurrent problems with water intrusion. The failure of the licensee to implement adequate corrective actions to address the water

intrusion problems on April 12, 1999, is a violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action." This Severity Level IV violation is being treated as a Non-Cited Violation. (08/09/1999, 1999008)

On May 25, 1999, from operation at full power, operators initiated a manual reactor trip at Unit 2 when a steam leak developed in the turbine building as a result of a transient in the feedwater heaters. Operator performance in isolating the steam leak and placing the plant in a stable condition was good. The feedwater heater transient was caused by improper setup of the feedwater heater level control valves. Inadequate procedural control was identified as the root cause, with inadequate initial design and inadequate corrective actions to address recurring level control problems identified as contributing causes. The transient developed into a steam leak because generic engineering guidance for selecting torque values was improperly applied in the selection of torque values for the feedwater heater relief valve flange fasteners. The NRC found that the corrective actions implemented prior to restart were adequate to address the direct causes of the feedwater heater level control problems and the subsequent steam leak. (06/14/1999, 1999006)

B5. Although many design control and configuration management deficiencies were identified and corrected during the extended outage, some additional examples have been identified post-restart.

The NRC found that design control measures were inadequate to assure that the 4160 volt switchgear room coolers were capable of maintaining a suitable environment for the vital switchgear under post-accident conditions. This Severity Level IV violation of design control requirements is being treated as a Non-Cited Violation. The licensee's determination that the "A" train 4160 volt switchgear remained operable when the switchgear room cooler was removed from service for corrective maintenance was found acceptable. (10/04/1999, 1999009)

On May 25, 1999, from operation at full power, operators initiated a manual reactor trip at Unit 2 when a steam leak developed in the turbine building as a result of a transient in the feedwater heaters. The feedwater heater transient was caused by improper setup of the feedwater heater level control valves. Inadequate procedural control was identified as the root cause, with inadequate initial design and inadequate corrective actions to address recurring level control problems identified as contributing causes. The transient developed into a steam leak because generic engineering guidance for selecting torque values was improperly applied in the selection of torque values for the feedwater heater relief valve flange fasteners. The NRC found that the corrective actions implemented prior to restart were adequate to address the direct causes of the feedwater heater level control problems and the subsequent steam leak. (06/14/1999, 1999006)

B6. Early in this period the licensee resolved some long standing problems associated with the PASS system while other minor problems still exist. In September 1999, several objectives during the off year exercise were not met. The

EP program has generally been improving but some areas need further attention by the licensee. Overall, the program is being satisfactorily implemented.

At Unit 2, the licensee adequately demonstrated the operation of the PASS. Sample results met the appropriate acceptance criteria and although the licensee could not consistently meet the total dissolved gas (TDG) acceptance criteria, the TDG concentration results were marginally outside the acceptance value. The licensee is continuing to assess the method for retrieving and analyzing a TDG for better accuracy. Revised/approved PASS procedures were found to be detailed, technicians were retrained, equipment deficiencies were corrected and the system was repeatedly tested. The licensee adequately demonstrated an emergency PASS drill and met the time requirement for obtaining post-accident sample results within three hours. (4/19/1999, 1999005)

On September 15, 1999, the licensee conducted its off year exercise. The licensee's evaluation of the exercise was thorough and identified both positive and negative findings and concluded that the health and safety of the public would have been protected. The licensee's critique communicated the failure of five exercise objectives in the areas of accident projection, emergency classification, notification of onsite/offsite responders, communications between facilities, and magnitude of release components. The inspector noted senior licensee management support of the EP program during the critique, evidenced by their statements to take any actions necessary to improve the organization's performance in this area. The inspector noted that a CR was written to document the evaluation findings and effect corrective actions. (10/04/99, 1999009)

C. Reactor Safety - Inspection Program Recommendations

A Region I specialist inspection of some modifications, relating to the impact of decommissioning activities at Unit 1 upon the Unit 2 and Unit 3 alternate ac power supplies, has been recommended by the Millstone Assessment Panel for the first quarter of CY 2000.

RADIATION SAFETY

A. Radiation Safety - Assessment

We did not identify any significant performance issues in the radiation safety strategic area. As a result, only baseline inspections are planned.

B. Radiation Safety - Basis

Radiological controls were effectively implemented during a Unit 2 forced outage in late September 1999. The internal exposure measurement and dose assessment program at Millstone is effective. The RP program has an active oversight and self-assessment program that engages problems in an effective manner. (10/04/99, 1999-009)

The licensee conducted an aggressive and comprehensive event review of a 7.04 rem TLD exposure that did not uncover any significant program deficiencies. (08/09/99, 1999-008)

During the Spring 1999 Unit 3 refueling outage, two instances were reported where alarming dosimeters used for high radiation area entries, were not audible and resulted in additional exposure to personnel. This resulted in an NCV. (06/14/99, 1999-006)

The radiological environmental monitoring program was effectively implemented. (04/19/99, 1999-005)

The licensee maintained an effective radiological effluents program. (04/19/99, 1999-005)

C. Radiation Safety - Inspection Program Recommendations

Baseline inspection activities are planned.

PHYSICAL PROTECTION

A. Physical Protection - Assessment

We did not identify any significant performance issues in the physical protection strategic area. As a result, only baseline inspections are planned.

B. Physical Protection - Basis

The licensee was conducting security and safeguards activities in accordance with regulatory requirements. A weakness was identified in the onsite coverage of radio communications. (12/9/99 DRAFT, 1999-014 DRAFT)

C. Physical Protection - Inspection Program Recommendations

Baseline inspection activities are planned.

CROSS CUTTING ISSUES

A. Cross Cutting - Assessment

The NRC identified several instances where the licensee staff failed to initiate condition reports, which resulted in untimely or inadequate corrective actions. Examples were water intrusion into the bearing oil of a Unit 2 auxiliary feedwater pump and air entrapment in the piping from the Unit 2 recirculation sump. In both cases, safety systems were significantly degraded. Other failures resulted in the untimely initiation of operability determinations. In addition, a condition report was not written when the operators recorded data at a higher power level than specified in a procedure during a Unit 2 reactor startup. Notwithstanding, the NRC has found the overall, the problem

identification threshold was low, with a high volume of items being generated and processed on a daily basis (In 1999, 3322 condition reports were generated). In general, condition reports provide an effective means of communicating identified concerns to plant management in a timely manner.

A generally healthy safety conscious work environment existed at Millstone. Both Little Harbor Consultants and the NRC noted improvement during the assessment period. The licensee had appropriate programs and processes established to address employee concerns and to monitor and evaluate the safety conscious work environment. Specifically, the Employee Concerns Program department, the Safety Conscious Work Environment department, and the Employee Concerns Oversight Panel were effective in performing these duties. Although some deficiencies were found, they did not detract from the overall effectiveness of the programs and processes. Site employees were familiar with programs and processes for handling concerns, and they would be willing to raise nuclear safety concerns. Challenges to a safety conscious work environment remained due to the ongoing supervisor cascade, the contracting of Entergy to manage the decommissioning of Unit 1, planned reductions in contractor and licensee positions and consideration of a revised pay structure.

The number of allegations received by the NRC during this 12 month PPR period (23) is less than the number received during the previous 12 month period (32). Considering the fact that 10 allegations were received during the first three months and 6 were received during the next three months, the rate of allegation receipt for the last six months was substantially reduced. Although the number of H&I concerns received during Fiscal Year 1999 (11) was higher as compared to Fiscal Year 1998 (7), this trend was not significant because one concern was submitted twice, three concerns were similar, and one concern was four years old. Additionally, none of the H&I concerns have yet been substantiated.

B. Cross Cutting - Basis

B1. The NRC identified several instances where the licensee staff failed to initiate condition reports, which resulted in untimely or inadequate corrective actions.

At Unit 2, the NRC identified that the licensee failed to initiate a condition report to document that, during the reactor startup, reactor criticality occurred at a higher power level than expected which resulted in the recording of critical data at power level that was higher than power level specified in the procedure. A condition report is necessary to ensure that the cause of the higher power level is evaluated and that corrective actions are taken to prevent recurrence during future reactor startups. The failure to initiate a condition report as required by the corrective action procedure is being treated as a Non-Cited Violation. (10/04/1999, 1999009)

At Unit 2, operators failed to initiate a condition report and take timely corrective actions when they suspected that the piping between the "B" train containment sump isolation

valve and the downstream check valve was not full of water. Trapped air in the piping had the potential to render the "B" train high pressure safety injection (HPSI) and containment spray pumps inoperable. However, operators inappropriately determined that it was acceptable to wait up to four weeks to determine whether the piping contained air. Prompt actions, including the confirmation of trapped air in the containment sump suction piping, were not taken until concerns were raised by the NRC inspector about three weeks later. Although the amount of trapped air was small and would not have prevented the "B" HPSI and containment spray pumps from performing the intended function, the failure to address this deficient condition in a timely manner is a violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action." This Severity Level IV violation is being treated as a Non-Cited Violation. (08/09/1999, 1999008)

Prior to Unit 2 plant startup, the licensee failed to initiate a condition report when a five-day trend showed the No. 3 safety injection tank (SIT) was leaking by the closed isolation valve to the reactor coolant system (RCS). A condition report was necessary to initiate an assessment of SIT operability with the leaking isolation valve. Following an NRC inquiry, a condition report was initiated and the licensee's operability determination found the SIT to be operable. The NRC found that the operability determination was adequately supported and an acceptable corrective action plan was developed. The failure to initiate a condition report is a violation of 10 CFR Part 50, Appendix B, Criterion V, "Instruction, Procedures and Drawings." This Severity Level IV violation is being treated as a Non-Cited Violation. (08/09/1999, 1999008)

At Unit 2, the licensee failed to initiate a condition report and implement effective corrective actions when a significant amount of water was identified in the oil removed from the outboard bearing of the "B" auxiliary feed water pump during a scheduled oil change on April 12, 1999. As a result, the condition recurred during continuous operation of the pump from May 25 through 29, 1999, and the degraded condition was not identified and corrected until June 1, 1999. In addition, the licensee's assessment of operability during the period prior to June 1, 1999, was not well founded in that it was based on the ability of the system, rather than the component, to perform its design function. Finally, the licensee inappropriately used the conclusion that the pump had been operable as a basis to reduce the degree of thoroughness in identifying and implementing corrective actions to address the recurrent problems with water intrusion. The failure of the licensee to implement adequate corrective actions to address the water intrusion problems on April 12, 1999, is a violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action." This Severity Level IV violation is being treated as a Non-Cited Violation. (08/09/1999, 1999008)

At Unit 2, following the repair of a reactor building closed cooling water (RBCCW) throttle valve, the licensee failed to initiate a condition report when RBCCW flow to the "B" containment air recirculation cooler significantly exceeded the post-maintenance acceptance criteria. Because this higher flow rate could have resulted in insufficient RBCCW flow to other safety-related components, a condition report was necessary to initiate an operability assessment of the "B" RBCCW train, which was in service.

Although a subsequent evaluation showed that the RBCCW flow to other safety-related components would have remained within established margins, the failure to initiate a condition report, as required by the licensee's administrative procedure governing their corrective action program, is a violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings." This Severity Level IV violation is being treated as a Non-Cited Violation. (NCV 50-336/99-08-06) In addition, rather than using an approved procedure, an engineering disposition was inappropriately used to provide instructions to manipulate the in-service RBCCW system to establish a new throttle position for the repaired valve. (08/09/1999, 1999008)

Unit 2 personnel failed to initiate Condition Reports in accordance with station procedure RP4, "Corrective Action Program," for the proper evaluation of conditions adverse to quality involving the charging pump hand switches and reactor building closed cooling water system valve 2-RB-210 leakage. This Severity Level IV violation of procedural requirements is being treated as a Non-Cited Violation, consistent with Appendix C of the NRC Enforcement Policy. Other tracking systems were used to ensure final resolution of these control room deficiencies, but these tracking mechanisms lacked appropriate operability reviews to assess system or plant impact. (02/17/1999, 1999001)

B.2 A generally healthy safety conscious work environment existed at Millstone.

Generally, the team observed a healthy safety conscious work environment at Millstone. (8/27/99; 99-07)

The team observed a generally healthy safety conscious work environment at Millstone. (10/27/99; 99-11)

B.3 Both Little Harbor Consultants and the NRC noted improvement during this assessment period.

Little Harbor Consultants (LHC) observed that there has been improvement in most areas since June 1999. All programs and policies put in place to enhance site performance with respect to a safety conscious work environment are functioning reasonably well. (10/27/99; 99-11)

We noted overall improvement in most areas since the NRC's previous assessment in June 1999. (10/27/99; 99-11)

B.4 The licensee has appropriate programs and processes established to address employee concerns and to monitor and evaluate the safety conscious work environment. Specifically, the Employee Concerns Program department, the Safety Conscious Work Environment department, and the Employee Concerns Oversight Panel were effective in performing these duties.

The Employee Concerns Oversight Panel (ECOP) was effective in providing oversight of

the safety conscious work environment at Millstone. The team determined that the ECOP quarterly report was comprehensive and provided detailed information that site management could use to assess the safety conscious work environment at Millstone. (10/27/99; 99-11)

The Employee Concerns Program (ECP) organization continued to possess the independence, resources and management support to perform thorough, unbiased investigations of employee concerns. (8/27/99; 99-07)

The Employee Concerns Program (ECP) department was adequately staffed and was effective in handling employee concerns. Generally, key performance indicators (KPIs) showed positive or steady trends and performance in the ECP area. The ECP department continued to perform thorough investigations. The quality of the ECP case files was high, with good investigative work noted. (10/27/99; 99-11)

The Safety Conscious Work Environment (SCWE) department used the SCWE Case Process appropriately to address significant concerns based on established criteria. Action plans were well developed, and planned actions and assessment activities appeared to have been implemented in a timely manner. (10/27/99; 99-11)

The Core Group and the targeted workplace surveys were effective tools for monitoring the safety conscious work environment at Millstone. The survey reports provided a thorough evaluation of the survey results. (10/27/99; 99-11)

B.5 Although some deficiencies were found, they did not detract from the overall effectiveness of the programs and processes.

Two KPIs, the backlog of cases under investigation and the backlog of open ECP corrective actions, showed negative trends. To help reduce the backlog of cases under investigation, the licensee was training an individual to become an ECP investigator. However, site management attention is warranted to address the increasing backlog of ECP corrective actions. In all but one ECP case file, the investigations properly supported the conclusions. The ECP department reopened this investigation. The ECP department did not begin an investigation into a potential harassment, intimidation, retaliation, and discrimination (HIRD) issue until eight weeks after they had received the concern. The licensee is considering enhancing their process to prevent recurrence. (10/27/99; 99-11)

The recommendations from the Core Group and targeted workplace surveys did not always result in timely, proactive corrective actions. (10/27/99; 99-11)

In SCWE case files, the team identified discrepancies in the documentation and tracking of actions and assessment activities, most notably in older case files. (10/27/99; 99-11)

B.6 Site employees were familiar with programs and processes for handling concerns,

and they would be willing to raise nuclear safety concerns.

Employee surveys, assessments and team interviews indicated that the majority of employees were willing to raise concerns. As part of the review of corrective actions, the team queried employees regarding their willingness to raise concerns to management. Based on this limited survey, employees indicated no reluctance to raise safety concerns. In particular, employees indicated that they felt comfortable raising issues through the corrective action processes. However, there was an indication that some workers did not want to be obstacles to meeting schedules and deadlines, and another indication that the on-going reduction in the number of supervisors (supervisory cascade) might have some influence on the ease for potential supervisors to raise issues. (8/27/99; 99-07)

Team interviews found that site employees were familiar with programs and processes for handling concerns, and they would be willing to raise nuclear safety concerns. (10/27/99; 99-11)

B.7 Challenges to a safety conscious work environment remained due to the ongoing supervisor cascade, the contracting of Entergy to manage the decommissioning of Unit 1, planned reductions in contractor and licensee positions and consideration of a revised pay structure.

The ongoing supervisor cascade, the contracting of Entergy to manage the decommissioning of Unit 1, the planned staff reductions in contractor and licensee positions, and the consideration of a revised pay structure represented significant personnel impacts and a potential challenge to the safety conscious work environment. With these major activities, the site's ability to maintain and monitor the safety conscious work environment will be significantly tested. The Human Services organization, in coordination with other organizations, had recognized these challenges. Taking advantage of the SCWE organization and its processes, the licensee had initiated actions to mitigate the impact of these changes and their impact. (8/27/99; 99-07)

C. Cross Cutting - Inspection Program Recommendations

A 40500 initiative inspection was performed the week of January 31, 2000. Preliminary results reveal several additional examples of failing to initiate condition reports, although the new issues were of lesser safety significance. Through the baseline inspection program, resident inspectors will continue to monitor this area.

The NRC will monitor the safety conscious work environment through reviews of future Little Harbor Reports, resident observations and other NRC processes. Based upon these observations, the need for NRC inspections using procedure 40001 will be assessed.

III. ATTACHMENTS

Millstone Inspection Directorate PPR: Millstone Unit 2

- **Plant Issues Matrix**
- **Draft PPR Letter with inspection plan**
- **Power History Charts**
- **Plant Strategy**
- **Performance Indicators**
- **Previous PPR letters (Last full PPR and mid-cycle)**
- **Open Item Assessment**

INCLUDES DRAFT ITEMS

Region I

05000336 - Millstone 2

United States Nuclear Regulatory Commission
PLANT ISSUE MATRIX
By Primary Functional Area / Issue Date

Date	Source	Functional Area	ID	Type	Template Codes	Item Title / Item Description
11/22/1999	1999012-01	Pri: OPS	NRC	NCV	Pri: 1A	**FAILURE TO ADEQUATELY IMPLEMENT THE OPERATING PROCEDURE TO MAINTAIN THE AXIAL POWER DIST**
Record ID: 78876		Sec:			Sec:	Operators did not adequately anticipate the effect of xenon during a planned power increase from 84 to 100 percent power. Consequently, this routine power increase was performed in a manner that resulted in the reactor's axial power distribution value exceeding the limit specified in the operating procedure, the receipt of multiple reactor protection system pre-trip alarms for local power density, and the unplanned need to add multiple batches of concentrated boric acid to restore axial power distribution within the specified limit. The failure to adequately implement the operating procedure to maintain the axial power distribution value within the specified limit, as required by Technical Specification 6.8.1, is being treated as a Non-Cited Violation.
					Ter:	
10/04/1999	1999009	Pri: OPS	NRC	NEG	Pri: 1C	**WEAK CIRCULATING WATER SYSTEM OPERATING PROCEDURE**
Record ID: 78852		Sec:			Sec:	At Unit 2, the circulating water system operating procedure was weak in that it did not specify the reactor power level to allow securing a circulating water pump. As a result when a circulating water pump was secured at 85% power, numerous main condenser alarms and reduced main condenser vacuum occurred, which unnecessarily challenged plant operators.
					Ter:	
10/04/1999	1999009	Pri: OPS	NRC	POS	Pri: 1A	**REACTOR STARTUP FROM FORCED OUTAGE**
Record ID: 78853		Sec:			Sec:	At Unit 2, during the forced outage that occurred due to a dropped control rod, the licensee's corrective actions were found acceptable in addressing an electrical ground in the wire to the lower gripper coil which caused the rod to drop. The pre-evolution briefing of operators prior to reactor startup was thorough with a good discussion of industry operating experience and extra operator staffing was provided during the startup.
					Ter:	
10/04/1999	1999009	Pri: OPS	NRC	POS	Pri: 1B	**GOOD OPERATOR RESPONSE TO DROPPED CONTROL ROD**
Record ID: 78851		Sec:			Sec:	At Unit 2, on September 17, 1999, operators appropriately implemented the required actions for a dropped control rod and performed a reactor shutdown in a controlled and deliberate manner. Operator performance was particularly good in that the dropped rod occurred at a time they were responding to numerous main condenser alarms that resulted when the "D" circulating water pump was secured.
					Ter:	
10/04/1999	1999009	Pri: OPS	NRC	POS	Pri: 1B	**GOOD OPERATOR RESPONSE TO FEEDWATER SYSTEM**
Record ID: 78854		Sec:			Sec: 3A	At Unit 2, when a control circuit card failed for the main feedwater regulating bypass valve, reactor operator performance was good in immediately recognizing, before any alarms were received, that the bypass valve had closed. Due to prompt action by the reactor operator to restore main feedwater flow, a plant transient was averted.
					Ter:	
10/04/1999	1999009-02	Pri: OPS	NRC	NCV	Pri: 1C	**FAILURE TO ADEQUATELY ESTABLISH AND MAINTAIN PLANT COOLDOWN PROCEDURE TO REFLECT A CHAN**
Record ID: 78845		Sec:			Sec:	At Unit 2, the licensee failed to revise the plant cooldown procedure to reflect a change in reactor protection system (RPS) setpoints in April 1999. As a result, an unplanned RPS actuation on low steam generator level occurred while the plant was shut down. The failure to adequately maintain the plant cooldown procedure is being treated as a Non-Cited Violation
					Ter:	

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PLANT ISSUE MATRIX
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Date	Source	Functional Area	ID	Type	Template Codes	Item Title / Item Description
10/04/1999	1999009-03	Pri: OPS	NRC	NCV	Pri: 4C	**FAILURE TO REPORT AN UNPLANNED ACTUATION OF RPS**
Record ID: 78846		Sec:			Sec:	The licensee incorrectly retracted their initial notification of an unplanned RPS actuation. This retraction constitutes a failure to report a condition as required by 10 CFR 50.72 and is being treated as a Non-Cited Violation
					Ter:	
10/04/1999	1999009-04	Pri: OPS	NRC	NCV	Pri: 5A	**FAILURE TO INITIATE A CONDITION REPORT TO DOCUMENT THAT CRITICAL DATA WAS NOT TAKEN AT THE S**
Record ID: 78847		Sec:			Sec:	At Unit 2, the NRC identified that the licensee failed to initiate a condition report to document that, during the reactor startup, reactor criticality occurred at a higher power level than expected which resulted in the recording of critical data at power level that was higher than power level specified in the procedure. A condition report is necessary to ensure that the cause of the higher power level is evaluated and that corrective actions are taken to prevent recurrence during future reactor startups. The failure to initiate a condition report as required by the corrective action procedure is being treated as a Non-Cited Violation
					Ter:	
08/09/1999	1999008-01	Pri: OPS	NRC	NCV	Pri: 5A	**FAILURE TO PROMPTLY ADDRESS POTENTIAL AIR ENTRAPMENT IN THE EMERGENCY CORE COOLING SYSTE**
Record ID: 78826		Sec:			Sec: 1A	At Unit 2, operators failed to initiate a condition report and take timely corrective actions when they suspected that the piping between the "B" train containment sump isolation valve and the downstream check valve was not full of water. Trapped air in the piping had the potential to render the "B" train high pressure safety injection (HPSI) and containment spray pumps inoperable. However, operators inappropriately determined that it was acceptable to wait up to four weeks to determine whether the piping contained air. Prompt actions, including the confirmation of trapped air in the containment sump suction piping, were not taken until concerns were raised by the NRC inspector about three weeks later. Although the amount of trapped air was small and would not have prevented the "B" HPSI and containment spray pumps from performing the intended function, the failure to address this deficient condition in a timely manner is a violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action." This Severity Level IV violation is being treated as a Non-Cited Violation. (NCV 50-336/99-08-01)
					Ter: 1C	
08/09/1999	1999008-02	Pri: OPS	NRC	NCV	Pri: 5A	**FAILURE TO INITIATE A CONDITION REPORT WHEN A LEAKING SAFETY INJECTION ACCUMULATOR ISOLATIO**
Record ID: 78828		Sec:			Sec: 1A	Prior to Unit 2 plant startup, the licensee failed to initiate a condition report when a five-day trend showed the No. 3 safety injection tank (SIT) was leaking by the closed isolation valve to the reactor coolant system (RCS). A condition report was necessary to initiate an assessment of SIT operability with the leaking isolation valve. Following an NRC inquiry, a condition report was initiated and the licensee's operability determination found the SIT to be operable. The NRC found that the operability determination was adequately supported and an acceptable corrective action plan was developed. The failure to initiate a condition report is a violation of 10 CFR Part 50, Appendix B, Criterion V, "Instruction, Procedures and Drawings." This Severity Level IV violation is being treated as a Non-Cited Violation. (NCV 50-336/99-08-02)
					Ter: 1C	
06/14/1999	1999006	Pri: OPS	NRC	NEG	Pri: 1A	**Unit 2 Poor Operator Communication with other Work Groups**
Record ID: 78729		Sec:			Sec:	Although communications between operators was a strength, examples of poor communication between operators and other work groups led to plant configuration changes without operator knowledge.
					Ter:	

United States Nuclear Regulatory Commission
PLANT ISSUE MATRIX
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Date	Source	Functional Area	ID	Type	Template Codes	Item Title / Item Description
06/14/1999	1999006	Pri: OPS	NRC	NEG	Pri: 1C	**Unit 2 Operating Procedure Inadequacy**
Record ID: 78730		Sec:			Sec:	During a pre-job brief an operator identified an inadequate surveillance for the atmospheric dump valves which if performed as written could have resulted in a reactor trip. Although it is good that operators are properly addressing these procedural issues as they arise, reliance on individuals performing the procedures to identify procedural deficiencies presents an unnecessary challenge to plant personnel.
					Ter:	
06/14/1999	1999006	Pri: OPS	NRC	POS	Pri: 1A	**Unit 2 Startup and Power Ascension**
Record ID: 78687		Sec:			Sec:	Unit 2 startup and power ascension was performed in a controlled and conservative manner following a shutdown which lasted in excess of three years. Operators performed evolutions slowly and deliberately and executed the power ascension without any significant events. Line management and nuclear oversight maintained a strong presence in the control room and provided a positive influence on the conduct of operations.
					Ter:	
06/14/1999	1999006-01	Pri: OPS	NRC	NCV	Pri: 1C	**Unit 2 (Closure of URI 96-09-09) Failure to Provide Procedural Guidance for Bypassing Automatic Actuation of**
Record ID: 78731		Sec:			Sec:	At Unit 2, the failure of the licensee to establish adequate procedural guidance for intentionally bypassing the automatic actuation of the engineered safeguards actuation system is a violation of Technical Specification 6.8.1. This Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Appendix C of the NRC Enforcement Policy. This failure occurred following issuance of a related NRC Information Notice.
					Ter:	
03/05/1999	1998219-04	Pri: OPS	NRC	NCV	Pri: 1C	**Unit 2 Inadequate Procedure Controls Closure of Steam Supply Valve to Turbine-Driven Auxiliary Feed Pump**
Record ID: 78748		Sec: ENG			Sec: 4A	In URI 98-203-10, the NRC noted that Operating Procedure (OP) 2322, "Auxiliary Feedwater System," provided instructions and allowed continued power operations of the reactor with one of the two steam supplies to the turbine-driven auxiliary feedwater (TDAFW) pump (2-MS-201 or 2-MS-202) closed. The procedure required that the operator take specific manual actions in areas outside the control room before starting the TDAFW pump. The licensing and design bases for Millstone Unit 2 require that the TDAFW pump be started from the control room within 10 minutes after a loss-of-feedwater event. The licensee determined that the operator actions required to place the TDAFW pump on line would take longer than 10 minutes, which was inconsistent with the design basis of the plant. The failure of OP 2322 to provide adequate instructions for operation with 2-MS-201 or 2-MS-202 closed was identified as a violation of TS 6.8.1.
					Ter:	
04/19/1999	1999005	Pri: OPS	NRC	POS	Pri: 4C	**Unit 2 Operating Procedure Agreement with Final Safety Analysis Report**
Record ID: 78632		Sec:			Sec:	Following the licensee's Configuration Management Plan (CMP) effort, which was intended to identify discrepancies related to the Final Safety Analysis Report (FSAR), 1998 NRC Inspection Reports and a Northeast Utilities (NU) self-assessment documented additional examples of operating procedures that were not consistent with the FSAR. Based on these findings, NU conducted an expanded review of approximately 50 systems to identify instances where operating procedures did not reflect final safety analysis report requirements. This expanded review was acceptable and the few identified deficiencies were appropriately dispositioned.
					Ter:	
04/07/1999	1999004	Pri: OPS	NRC	POS	Pri: 1A	**Unit 2 Operational Safety Team Inspection - Conduct of Operations**
Record ID: 78661		Sec:			Sec:	Unit 2 operations department had sufficient personnel to provide coverage throughout the restart period without excessive use of overtime. The shift turnovers observed were of high quality with active participation from groups supporting operations. Pre-job briefings were generally good with a few minor communications weaknesses. Significant Item List No. 13 is closed.
					Ter:	

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Date	Source	Functional Area	ID	Type	Template Codes	Item Title / Item Description
04/07/1999	1999004	Pri: OPS	NRC	POS	Pri: 1A	**Unit 2 Operational Safety Team Inspection - Operator Knowledge, Performance and Training**
Record ID: 78663		Sec:			Sec:	Unit 2 operator performance was generally good and control room demeanor was observed as appropriate. Both licensed and non-licensed operators were aware of plant conditions and maintenance activities in progress. The operators conducted plant evolutions in a safe and controlled manner, and exhibited a conservative approach to equipment manipulation. Generally, control room operators expeditiously identified plant equipment malfunctions or changes in plant conditions. Generally, operator control board awareness and annunciator response were good.
					Ter:	
04/07/1999	1999004	Pri: OPS	NRC	POS	Pri: 1A	**Unit 2 Operational Safety Team Inspection - Quality Assurance in Operations**
Record ID: 78666		Sec:			Sec:	Nuclear oversight observations provided accurate accounts of activities involving the conduct of operations. Self-assessments were critical and the licensee's corective action plans for improvement were appropriate.
					Ter:	
04/07/1999	1999004	Pri: OPS	NRC	POS	Pri: 1C	**Unit 2 Operational Safety Team Inspection - Management (SIL 1)**
Record ID: 78657		Sec:			Sec:	Unit 2 Management Processes - Appropriate standards and expectations for safety were established by senior management and were understood by subordinate managers and staff. The team concluded that management expectations for safe plant operations were communicated, understood and followed by the plant staff. Senior plant management used a variety of communication methods to reinforce expectations. Management expectations regarding employee concerns were understood by the staff.
					Ter:	Planning and direction for the restart and recovery of Unit 2 were effective. The application of probabilistic risk assessment insights to design and operation of the plant were adequate. Effective leadership was provided and management involvement in routine activities and emerging issues was appropriate. The Nuclear Oversight Verification Plan and "windows" assessment tools were effective mechanisms for management to assess restart readiness. Significant Item List (SIL) Item No. 1, Management Oversight and Effectiveness; Licensee Staff Safety Culture, and the associated NRC Restart Assessment Plan items are closed.
04/07/1999	1999004	Pri: OPS	NRC	POS	Pri: 1C	**Unit 2 Operational Safety Team Inspection - Corrective Action Program**
Record ID: 78658		Sec:			Sec:	Unit 2 Corrective Action Program is adequate to support plant restart. Plant deficiencies are being included in the corrective action program and recent root cause evaluations are thorough. The licensee's backlog management plan was adequate and the licensee's process for deferral contained appropriate methodology for the identification of items acceptable for deferral and completion after the Unit 2 restart. Significant Item List No. 12 is closed.
					Ter:	
04/07/1999	1999004	Pri: OPS	NRC	POS	Pri: 1C	**Unit 2 Operational Safety Team Inspection - Independent Oversight (Nuclear Oversight Verification Plan)**
Record ID: 78659		Sec:			Sec:	The Nuclear Oversight Verification Plan provides effective independent assessment of performance for resolution of "key issues". The Nuclear Oversight Organization's involvement in operations, maintenance, surveillance and engineering has been satisfactory. Line organization cooperation and support for oversight activities was apparent. The team concluded that the various reporting mechanisms employed by the nuclear oversight organization provided an effective means of capturing conditions adverse to quality and ensuring that those conditions were corrected. The reports were critical assessments and provided senior management with a useful "snapshot" of plant performance and areas requiring additional attention. Nuclear oversight audit findings with restart implications are being properly addressed.
					Ter:	

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Date	Source	Functional Area	ID	Type	Template Codes	Item Title / Item Description
04/07/1999	1999004	Pri: OPS	NRC	POS	Pri: 1C	**Unit 2 Operational Safety Team Inspection - Quality Review Committees**
Record ID: 78660		Sec:			Sec:	The Millstone quality review committees, including the plant operations review committee (PORC), station operations review committee (SORC) and nuclear safety assessment board (NSAB) all meet the technical specification (TS) requirements. The team concluded that the NSAB was providing effective independent oversight.
					Ter:	
04/07/1999	1999004	Pri: OPS	NRC	POS	Pri: 1C	**Unit 2 Operational Safety Team Inspection - Operations Training, Organization, and Administration**
Record ID: 78665		Sec:			Sec:	Unit 2 licensed operators had satisfactorily completed requalification training. A review of the lesson plans, discussions with licensed operators, and observation of plant and simulator performance indicated that the training provided to the operators was sufficient to ensure that they could safely restart the unit. Modification training for the operators was appropriate to effectively communicate plant changes completed during the outage. Operations department staffing levels were adequate to support the safe operation of the plant. Communications within the operations department and with other site organizations were good. Operators generally initiated operability determinations in response to degraded equipment conditions. The team observed good command and control of shift activities.
					Ter:	
04/07/1999	1999004-01	Pri: OPS	NRC	NCV	Pri: 1A	**Unit 2 Operational Safety Team Inspection - Operator Performance**
Record ID: 78664		Sec:			Sec:	Unit 2 operators, in one case, failed to monitor, in a timely manner, steam generator temperatures in accordance with a technical specification surveillance test requirement. There were no safety consequences as a result of not conducting this surveillance because the required plant parameters were always satisfied. The failure to conduct this technical specification required surveillance is a violation of NRC requirements. This Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Appendix C of the NRC Enforcement Policy. On several occasions operators failed to appropriately communicate unexpected alarms to the Unit Supervisor.
					Ter:	
03/01/1999	1999002-01	Pri: OPS	Self	NCV	Pri: 1A	**Unit 2 Inadvertent Reactor Coolant System Water Level Increase**
Record ID: 78617		Sec:			Sec: 3A	At Unit 2, while in Mode 5, an inadvertent increase in reactor coolant system (RCS) level of approximately 25 inches occurred when the safety injection tank (SIT) outlet motor operated valves (MOVs) were opened to perform testing because operators failed to recognize the potential for a significant quantity of water in the SIT lower head and its injection piping to be present and drain to the RCS. Consequently, the operators did not request a procedure change to provide specific instructions and precautions for opening the valves while in this plant condition. The water that was added had approximately the same boron concentration as the RCS and water level remained several feet below the lowest open penetration in the reactor vessel head. The NRC concluded that the failure to establish adequate procedural controls for operation of the SIT outlet MOVs constituted a violation of Technical Specification 6.8.1.a.
					Ter: 3C	
03/01/1999	1999002-02	Pri: OPS	Self	NCV	Pri: 3A	**Unit 2 Inadvertent Transfer of Water from the Spent Fuel Pool**
Record ID: 78618		Sec:			Sec: 1A	At Unit 2, the operating procedure that provides instructions for draining the refueling cavity was inadequate in that, at the completion of the draining evolution, the procedure failed to direct the isolation of the flow path to the liquid radioactive waste system. Subsequently, the configuration established through use of this procedure led to the inadvertent loss of approximately 2 inches of spent fuel pool water level when about 2730 gallons of spent fuel pool water was transferred to the liquid radioactive waste system. However, performance of the plant equipment operator was good in promptly identifying and terminating the spent fuel pool water loss.
					Ter: 3C	

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Date	Source	Functional Area	ID	Type	Template Codes	Item Title / Item Description
03/01/1999 Record ID: 78619	1999002-03	Pri: OPS Sec: MAINT	Self	NCV	Pri: 1A Sec: 1C Ter:	**Unit 2 Inadvertent Charging Pump Injection** At Unit 2, although the testing portion of the integrated test of the Facility 1 engineered safety features components was well executed, the procedure instructions for restoration from the test were inadequately implemented. Steps to restore the "A" charging pump were performed in an inappropriate sequence, which resulted in the inadvertent start of the "A" charging pump. The subsequent injection of approximately 100 gallons of water from the volume control tank to the reactor coolant system (RCS) did not result in a reduction in RCS boron concentration. The NRC concluded that the surveillance procedure was weak in that, it allowed restoration steps to be performed out of sequence when the shift manager determined that the sequence of performance was unimportant and the procedure did not clearly identify restoration steps where the sequence of performance was important. The failure to adequately implement the surveillance procedure constituted a violation of Technical Specification 6.8.1.c.
02/17/1999 Record ID: 78616	1999001-01	Pri: OPS Sec:	NRC	NCV	Pri: 5A Sec: 4B Ter:	**Unit 2 Failure to Initiate a Condition Report for Two Control Room Deficiencies** Unit 2 personnel failed to initiate Condition Reports in accordance with station procedure RP 4, "Corrective Action Program," for the proper evaluation of conditions adverse to quality involving the charging pump hand switches and reactor building closed cooling water system valve 2-RB-210 leakage. This Severity Level IV violation of procedural requirements is being treated as a Non-Cited Violation, consistent with Appendix C of the NRC Enforcement Policy. Other tracking systems were used to ensure final resolution of these control room deficiencies, but these tracking mechanisms lacked appropriate operability reviews to assess system or plant impact.
D 02/14/2000 Record ID: 78911	2000001	Pri: OPS Sec: ENG	NRC	NEG	Pri: 2A Sec: 4A Ter: 1C	**MANUAL REACTOR TRIP RESULTING FROM A PARTIAL LOSS OF MAIN FEEDWATER FLOW** On January 27, 2000, when operators encountered problems restoring the sight-glass for the 2A main feedwater heater to service, operators cycled one of the sight-glass isolation valves, which was an evolution outside the scope of the operating procedure. The valve manipulation initiated a feedwater heater level transient that was exacerbated by longstanding sluggish operation of the 2A feedwater heater level control system, which had also contributed to a previous reactor trip on May 25, 1999. As a result of an original design problem associated with the heater drain tank, the feedwater heater level transient developed into an unanticipated total loss of heater drain flow, a trip of one main feedwater pump, and a subsequent manual reactor trip based on decreasing steam generator water levels. The NRC found that the corrective actions implemented prior to power ascension were adequate to address the direct causes of the partial loss of main feedwater flow and the subsequent reactor trip.
01/05/2000 Record ID: 78902	1999014	Pri: MAINT Sec:	NRC	NEG	Pri: 2B Sec: Ter:	**INCOMPLETE IMPLEMENTATION OF ON-LINE MAINTENANCE PROCEDURE** At Unit 2, the NRC identified that although the on-line maintenance procedure specified that Operations Manager approval was needed when the planned removal of equipment from service placed the plant in an "Orange" risk condition, the plant staff had not been documenting his approval. Because the Operations Manager was aware of the "Orange" conditions, he had approved the conditions. Therefore, no violation occurred. The licensee's corrective action, which involved changing the on-line maintenance procedure to remove the statement regarding Operations Manager approval, was found acceptable.

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Date	Source	Functional Area	ID	Type	Template Codes	Item Title / Item Description
01/05/2000	1999014-01	Pri: MAINT	NRC	NCV	Pri: 2B	**FAILURE TO PLACE RPS INTO A MAINTENANCE RULE (a)(1) STATUS**
Record ID: 78892		Sec:			Sec: 4B	The licensee failed to recognize that the established performance criteria of no repetitive functional failures for the reactor protection system was exceeded on May 28, 1999, and again exceeded in October and November 1999, when another three functional failures occurred. The licensee failed to place the system into an (a) (1) status and establish goals commensurate with safety in violation of 10 CFR 50.65(a)(1). As a result, the licensee was untimely in developing a plan to address recurrent instances where an RPS channel was rendered inoperable due to a drifting thermal margin/low pressure setpoint. This violation is being treated as a Non-Cited Violation, consistent with section VII.B.1.a of the NRC Enforcement Policy.
					Ter:	
01/05/2000	1999014-02	Pri: MAINT	NRC	NCV	Pri: 2B	**FAILURE TO ESTABLISH AND IMPLEMENT ADEQUATE TESTING OF THE SAFETY INJECTION RECIRCULATION H**
Record ID: 78893		Sec:			Sec:	The licensee identified in 1998 that the technical specification (TS) required, ASME code visual tests, had not been performed on portions of safety injection recirculation header piping. This is a violation of Unit 2 TS 4.0.5. The licensee's corrective actions were found acceptable. This violation of TS 4.0.5, is being treated as a Non-Cited Violation.
					Ter:	
01/05/2000	1999014-03	Pri: MAINT	NRC	NCV	Pri: 2B	**FAILURE TO ESTABLISH AND IMPLEMENT ADEQUATE CAR FAN TESTING**
Record ID: 78894		Sec:			Sec:	The licensee identified in 1998 that the technical specification (TS) required containment air recirculation fan start testing, had historically not been performed. This is a violation of TS 4.6.2.1.2. The licensee's corrective actions were found acceptable. This violation of TS 4.6.2.1.2, is being treated as a Non-Cited Violation.
					Ter:	
01/05/2000	1999014-04	Pri: MAINT	NRC	NCV	Pri: 2B	**FAILURE TO ESTABLISH AND IMPLEMENT ADEQUATE TESTING OF CERTAIN CHECK VALVES**
Record ID: 78895		Sec:			Sec:	The licensee identified in 1998 that the technical specification (TS) required check valve full flow tests had not been performed in accordance with ASME Section XI requirements, on specific check valves. This is a violation of TS 4.0.5. The licensee's corrective actions were found acceptable. This violation of TS 4.0.5, is being treated as a Non-Cited Violation.
					Ter:	
11/22/1999	1999012-02	Pri: MAINT	NRC	NCV	Pri: 3A	**FAILURE TO ADEQUATELY IMPLEMENT THE SURVEILLANCE PROCEDURE TO ADJUST "B" EDG OUTPUT VOLT**
Record ID: 78877		Sec:			Sec: 2B	Following surveillance testing and operation of the "B" emergency diesel generator (EDG) on July 7, 1999, the licensee failed to restore the automatic voltage regulator to the position specified in the associated surveillance procedure. As a result, the "B" EDG output voltage was well below normal at its next start and was close to rendering the "B" EDG inoperable. The failure to adequately implement the surveillance procedure is being treated as a Non-Cited Violation.
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10/04/1999	1999009	Pri: MAINT	NRC	POS	Pri: 3A	**FEEDWATER MAINTENANCE COORDINATED WITH OPERATIONS**
Record ID: 78855		Sec:			Sec:	At Unit 2, the replacement of a control circuit card for the main feedwater regulating bypass valve was well coordinated with operations and appropriate contingency measures were in place in the event an unexpected feedwater transient occurred during the card replacement.
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08/09/1999	1999008-03	Pri: MAINT	NRC	NCV	Pri: 2B	**INADEQUATE TROUBLESHOOTING PROCEDURE FOR THE "A" EMERGENCY DIESEL GENERATOR RELATED TO**
Record ID: 78829		Sec:			Sec:	In August 1997, the Unit 2 "A" emergency diesel generator (EDG) inadvertently started during troubleshooting activities. The root cause of the event was a failure to establish enough detail in a maintenance troubleshooting procedure to prevent an inadvertent EDG start. The licensee's corrective actions included establishing adequate procedural controls over troubleshooting activities on safety-related equipment. The root cause evaluation was thorough, and the immediate and long term corrective actions were adequate. The failure to establish and implement adequate procedures in accordance with Technical Specification 6.8.1 is a violation of NRC requirements. This Severity Level IV violation is being treated as a Non-Cited Violation (NCV 50-336/99-08-03). Licensee Event Report 50-336/97-027-00 is closed.
					Ter:	
08/09/1999	1999008-04	Pri: MAINT	NRC	NCV	Pri: 4B	**FAILURE TO MEET ASME SECTION XI SURVEILLANCE REQUIREMENTS RELATED TO LER 50-336/97-024-00 & 01**
Record ID: 78830		Sec:			Sec:	At Unit 2, the licensee identified in 1997 that they failed to meet certain portions of ASME Section XI surveillance requirements, as required by Unit 2 Technical Specifications (TS). The licensee's corrective actions included procedural changes, implementation of additional testing, and gaining approval to use specific code cases. The licensee properly reported, and corrected the deficiency. The root cause evaluation was thorough, and the immediate and long term corrective actions were adequate. The failure to meet the ASME Section XI testing requirements, as required by Unit 2 TS, is a violation of NRC requirements. This Severity Level IV violation is being treated as a Non-Cited Violation. (NCV 50-336/99-08-04) Licensee Event Report 50-336/97-024-00 &-01 is closed.
					Ter:	
04/19/1999	1999005	Pri: MAINT	NRC	POS	Pri: 1C	**Unit 2 Repair Associated with a Leaking Shutdown Cooling Suction Valve**
Record ID: 78638		Sec:			Sec:	At Unit 2, the NRC conducted extensive inspections of the repair activities associated with a leaking shutdown cooling suction valve, which was unisolable from the reactor coolant system (RCS) and was required to remain operable for RCS pressure boundary integrity and for decay heat removal in Operational Mode 5, cold shutdown. The NRC found that there were no regulatory requirements that would prohibit this repair and that the repair could be accomplished safely, without undue risk. The licensee implemented the repair in a controlled manner that maintained operability of the valve throughout the repair activities. The repair stopped the pressure seal leakage. The NRC found that the modification to weld a seal ring between the valve body and bonnet satisfied the American Society of Mechanical Engineers Boiler and Pressure Vessel Code requirements.
					Ter:	
04/19/1999	1999005-01	Pri: MAINT	Licensee	NCV	Pri: 1A	**Unit 2 (Closure of LER 96-24 & URI 96-08-09) Failure to Perform Response Time Testing of the Foxboro SPEC 20**
Record ID: 78639		Sec:			Sec:	Northeast Utilities' review of the failure to perform response time testing of the Foxboro SPEC 200 instrumentation used for the Reactor Protection and Engineered Safeguards Actuation Systems was comprehensive and resulted in the revision and/or development of several surveillance procedures. Subsequent testing verified that the response time of the affected safety-related loops was within the Technical Specification limits. This failure is a violation of 10 CFR 50, Appendix B, Criterion XI, "Test Control." This Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Appendix C of the NRC Enforcement Policy. Furthermore, the above evaluation and resolution of the issue acceptably addressed the NRC concerns regarding root cause and scope of testing.
					Ter:	
03/26/1999	1999003	Pri: MAINT	NRC	POS	Pri: 2A	**Unit 2 Fire Protection - Maintenance and Plant Equipment**
Record ID: 78679		Sec:			Sec:	Unit 2 plant equipment being used for post-fire safe shutdown was in good material condition and alternative shutdown capability could be operationally implemented in a timely manner with the current staffing level of operating shift. The licensee effectively implemented the fire barrier inspection of the group 9 seals. Additionally, the licensee identified deficiencies because of the increased training of the Site Fire Protection personnel, greater awareness of fire boundaries integrity on the site, and an improved inspection procedure. The corrective actions for the deficiencies appeared to be reasonable.
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04/07/1999	1999004	Pri: MAINT	NRC	POS	Pri: 1A	**Unit 2 Operational Safety Team Inspection - Conduct of Maintenance**
Record ID: 78667		Sec:			Sec:	Unit 2 maintenance activities observed were generally of good quality. Maintenance technicians conducted good pre-job briefings in the maintenance shops and briefed operators on job scope prior to beginning work. Procedure adherence by the maintenance staff was generally good. The team observed instances where work was stopped to clarify or revise maintenance procedures. The maintenance workers were knowledgeable of assigned maintenance tasks and had received appropriate training. The team concluded that the maintenance rework rate was at an acceptable level, and that the licensee had adequately resolved maintenance rework issues through the corrective action system. Appropriate maintenance supervisory oversight of field activities was observed.
					Ter:	
04/07/1999	1999004	Pri: MAINT	NRC	POS	Pri: 1C	**Unit 2 Operational Safety Team Inspection - Maintenance Organization and Procedures**
Record ID: 78669		Sec:			Sec:	Unit 2 maintenance were generally adequate for the intended tasks. Performance in the area of planning and scheduling was mixed. Planning was thorough, with detailed work packages prepared to support most AWO activities. Schedule adherence did not meet licensee's goals primarily due to emergent issues. The team did not observe any instances where schedule pressures or changes adversely affected plant safety. The licensee's performance in assessing the safety/risk of planned maintenance was acceptable. Safety assessments for maintenance activities were addressed by appropriate procedures and the risk significance of planned activities was discussed at planning meetings. Significant Item List No. 6 is closed.
					Ter:	
04/07/1999	1999004	Pri: MAINT	NRC	POS	Pri: 2A	**Unit 2 Operational Safety Team Inspection - Material Condition of Facilities**
Record ID: 78668		Sec:			Sec:	Unit 2 necessary equipment repairs were either completed or scheduled for completion prior to plant restart. Maintenance backlogs were being appropriately managed and routinely assessed for impact on operations. The control of operator work-arounds and control room deficiencies was also found to be adequate to support plant restart. The plant material condition and housekeeping were acceptable. The Backlog Reduction and Work-It-Now (WIN) Teams had a positive impact on addressing emergent work and reducing the automated work order (AWO) backlog. Significant Items List No. 7 is closed.
					Ter:	
01/05/2000	1999014	Pri: ENG	NRC	POS	Pri: 4B	**DEGRADED CONDITIONS AFFECTING THE REACTOR PROTECTION SYSTEM HAVE BEEN ADEQUATELY ADDRES**
Record ID: 78903		Sec:			Sec:	At Unit 2, the NRC concluded that the licensee's determination of continued operability of the reactor protection system, despite some degradation, was adequately founded. The majority of issues pose only a minimal increase in the probability of an inadvertent reactor trip or a distraction to the control operators and have no effect on the system's safety function. The licensee has implemented or scheduled appropriate measures to address the degraded conditions consistent with their importance to safety.
					Ter:	
01/05/2000	1999014-05	Pri: ENG	NRC	NCV	Pri: 4A	**FAILURE TO ADEQUATELY ESTABLISH AND IMPLEMENT DESIGN CONTROLS ASSOCIATED WITH SAFETY-REL**
Record ID: 78896		Sec:			Sec:	The licensee identified in 1998 that certain safety-related cable trays and cables did not meet design basis requirements for separation and/or placement. The licensee's corrective actions were found acceptable. This violation of 10 CFR 50, Appendix B, Criterion III, Design Control, is being treated as a Non-Cited Violation.
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01/05/2000	1999014-06	Pri: ENG	NRC	NCV	Pri: 4A	**FAILURE TO ADEQUATELY ESTABLISH AND IMPLEMENT DESIGN CONTROLS TO ENSURE THAT THE SAFETY-R**
Record ID: 78897		Sec:			Sec:	The licensee identified in 1998 that certain containment pressure instruments did not meet design basis requirements for post loss of coolant accident pressure retention. The licensee's corrective actions were found acceptable. This violation of 10 CFR 50, Appendix B, Criterion III, Design Control, is being treated as a Non-Cited Violation.
					Ter:	
01/05/2000	1999014-07	Pri: ENG	NRC	NCV	Pri: 4B	**FAILURE TO ADEQUATELY ESTABLISH AND IMPLEMENT DESIGN CONTROLS FOR THE PRESSURIZER SPRAY**
Record ID: 78898		Sec:			Sec:	The licensee identified in 1998 that pressurizer spray line operating procedures and practices did not meet the design basis requirements for reheating, maximum spray flow and other parameters affecting thermal fatigue parameters for the pressurizer spray line. The licensee's corrective actions were found acceptable. This violation of 10 CFR 50, Appendix B, Criterion III, Design Control is being treated as a Non-Cited Violation.
					Ter:	
11/22/1999	1999012-03	Pri: ENG	NRC	NCV	Pri: 4A	**INADEQUATE DESIGN CONTROLS TO ENSURE THAT REQUIRED CHILLED WATER FLOW IN THE VITAL SWITCH**
Record ID: 78878		Sec:			Sec:	The licensee reported on January 30, 1997, that the actual vital chilled water flow to the east and west DC switchgear room coolers was lower than the indicated flow and that the reduced flow would have resulted in room temperatures exceeding final safety analysis report post-accident design temperatures. This condition resulted from a failure to adequately implement design controls to ensure that required chilled water flow in the vital switchgear room coolers was correctly translated into specifications, drawings and procedures. This violation of 10 CFR 50, Appendix B, Criterion III, Design Control, is being treated as a Non-Cited Violation. The licensee's corrective actions were found acceptable. Licensee Event Report 50-336/96-43-00 is closed.
					Ter:	
11/22/1999	1999012-04	Pri: ENG	NRC	NCV	Pri: 4C	**FAILURE TO ESTABLISH AN ADEQUATE PROCEDURE FOR DAMPER TRACK INSPECTIONS AND FOR THE INSP**
Record ID: 78879		Sec:			Sec:	The NRC inspected a 1997 unresolved item (URI) and identified two instances where the licensee failed to establish and implement adequate fire protection program procedures. One instance was a failure to establish an adequate procedure for damper track inspections and a second instance was a failure to provide a method for the inspection of fire rated assemblies, fire barriers, and fire penetration seals. These two procedural inadequacies constitute a violation of Technical Specification 6.8.1 and are being treated as a Non-Cited Violation. Corrective Actions were found to be adequate. URI 50-336/97-84-02 is closed.
					Ter:	
11/22/1999	1999012-05	Pri: ENG	NRC	NCV	Pri: 2B	**FAILURE TO ADEQUATELY TEST TO ENSURE THAT AFW PUMP WAS CAPABLE OF OPERATING WITHIN THE R**
Record ID: 78880		Sec:			Sec: 4B	The licensee identified in 1998 that the "A" AFW pump was not capable of meeting its design basis flow rate following a modification performed on its impeller. The licensee's corrective actions were found acceptable. This violation of 10 CFR 50, Appendix B, Criterion XI, Test Control, is being treated as a Non-Cited Violation. Licensee Event Reports 50-336/98-04-00, 01, & 02 are closed.
					Ter:	
11/22/1999	1999012-06	Pri: ENG	NRC	NCV	Pri: 4A	**INADEQUATE DESIGN CONTROLS REGARDING RBCCW DESIGN CRITERIA UPON A LOSS OF SERVICE WATER**
Record ID: 78881		Sec:			Sec:	The licensee identified in 1998 that a postulated loss of a Unit 2 service water pump without operator action to trip the associated reactor building closed cooling water (RBCCW) pump could cause RBCCW system temperatures to exceed the design basis values established in the Unit 2 Final Safety Analysis Report. The resulting reduction in room cooling capability could have impacted equipment operability in the other train. This violation of 10 CFR 50, Appendix B, Criterion III, Design Control, is being treated as a Non-Cited Violation. The licensee's corrective actions were found acceptable. Licensee Event Report 50-336/98-06-00 is closed.
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11/22/1999 Record ID: 78882	1999012-07	Pri: ENG Sec:	NRC	NCV	Pri: 4A Sec: Ter:	**INADEQUATE DESIGN CONTROLS REGARDING AN AFW SINGLE FAILURE VULNERABILITY ON LOSS OF A DC** The licensee reported in 1998 that the auxiliary feedwater (AFW) system did not meet the revised loss of normal feedwater (LONF) safety analysis for the most limiting single failure. The postulated most limiting single failure could have resulted in less AFW flow to the steam generators than was credited in the Final Safety Analysis Report for a LONF event. This violation of 10 CFR 50 Appendix B, Criterion III, Design Control, is being treated as a Non-Cited Violation. The licensee's corrective actions were found acceptable. Licensee Event Reports 50-336/98-22-00, 01, & 02 are closed.
10/22/1999 Record ID: 78890	1999010-02	Pri: ENG Sec:	NRC	NCV	Pri: 5C Sec: Ter:	**FAILURE TO CORRECT IDENTIFIED CONDITIONS ADVERSE TO QUALITY** The licensee's Independent Safety Engineering Group determined that corrective actions for some prior deficiencies were ineffective or untimely. A specific example was the identified deficiency associated with the training documentation of engineering personnel that was not corrected in a timely manner to prevent a recurrence of the problem. The failure to correct conditions adverse to quality in a manner to prevent recurrence was a non-cited violation.
10/04/1999 Record ID: 78848	1999009-05	Pri: ENG Sec:	NRC	NCV	Pri: 4A Sec: 1C Ter:	**INADEQUATE DESIGN CONTROL MEASURES TO ASSURE THAT THE 4160 VOLT SWITCHGEAR ROOM COOLER** At Unit 2, the NRC found that design control measures were inadequate to assure that the 4160 volt switchgear room coolers were capable of maintaining a suitable environment for the vital switchgear under post-accident conditions. This Severity Level IV violation of design control requirements is being treated as a Non-Cited Violation (NCV 50-336/99-09-05). The licensee's determination that the "A" train 4160 volt switchgear remained operable when the switchgear room cooler was removed from service for corrective maintenance was found acceptable.
10/04/1999 Record ID: 78849	1999009-06	Pri: ENG Sec:	NRC	NCV	Pri: 4A Sec: Ter:	**(CLOSURE OF LER 97-35) SHUTDOWN COOLING ISOLATION VALVE DOES NOT COMPLY WITH APPENDIX R** At Unit 2, the licensee identified in 1997 that a valve that isolates the shutdown cooling system from the reactor coolant system was vulnerable to a fire-induced hot short. The licensee's corrective actions were found acceptable. This violation of 10 CFR 50, Appendix R, Fire Protection, is being treated as a Non-Cited Violation. Licensee Event Report 50-336/97-35-00 is closed.
10/04/1999 Record ID: 78850	1999009-07	Pri: ENG Sec:	NRC	NCV	Pri: 4A Sec: Ter:	**(CLOSURE OF LER 98-03) INADEQUATE DESIGN CONTROLS TO EVALUATE INTERACTION BETWEEN THE REAC** At Unit 2, the licensee identified in 1998 that the design analysis of the interaction between the reactor vessel internals and the reactor vessel did not properly address dynamic loading associated with a loss of coolant accident or a design bases earthquake. This violation of 10 CFR 50 Appendix B, Criterion III, Design Control, is being treated as a Non-Cited Violation. The licensee's corrective actions were found acceptable. Licensee Event Report 50-336/98-03-00 is closed.

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08/09/1999 Record ID: 78831	1999008-05	Pri: ENG Sec:	NRC	NCV	Pri: 5A Sec: 5B Ter: 5C	**FAILURE TO PROMPTLY ADDRESS WATER INTRUSTION INTO "B" AUXILIARY FEEDWATER PUMP BEARING** At Unit 2, the licensee failed to initiate a condition report and implement effective corrective actions when a significant amount of water was identified in the oil removed from the outboard bearing of the "B" auxiliary feed water pump during a scheduled oil change on April 12, 1999. As a result, the condition recurred during continuous operation of the pump from May 25 through 29, 1999, and the degraded condition was not identified and corrected until June 1, 1999. In addition, the licensee's assessment of operability during the period prior to June 1, 1999, was not well founded in that it was based on the ability of the system, rather than the component, to perform its design function. Finally, the licensee inappropriately used the conclusion that the pump had been operable as a basis to reduce the degree of thoroughness in identifying and implementing corrective actions to address the recurrent problems with water intrusion. The failure of the licensee to implement adequate corrective actions to address the water intrusion problems on April 12, 1999, is a violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action." This Severity Level IV violation is being treated as a Non-Cited Violation. (NCV 50-336/99-08-05)
08/09/1999 Record ID: 78832	1999008-06	Pri: ENG Sec:	NRC	NCV	Pri: 5B Sec: 1A Ter: 1C	**FAILURE TO WRITE A CONDITION REPORT FOR AN UNANALYSED FLOW DISTRIBUTION IN THE RBCCW SYSTE** At Unit 2, following the repair of a reactor building closed cooling water (RBCCW) throttle valve, the licensee failed to initiate a condition report when RBCCW flow to the "B" containment air recirculation cooler significantly exceeded the post-maintenance acceptance criteria. Because this higher flow rate could have resulted in insufficient RBCCW flow to other safety-related components, a condition report was necessary to initiate an operability assessment of the "B" RBCCW train, which was in service. Although a subsequent evaluation showed that the RBCCW flow to other safety-related components would have remained within established margins, the failure to initiate a condition report, as required by the licensee's administrative procedure governing their corrective action program, is a violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings." This Severity Level IV violation is being treated as a Non-Cited Violation. (NCV 50-336/99-08-06) In addition, rather than using an approved procedure, an engineering disposition was inappropriately used to provide instructions to manipulate the in-service RBCCW system to establish a new throttle position for the repaired valve.
08/09/1999 Record ID: 78833	1999008-07	Pri: ENG Sec:	NRC	NCV	Pri: 4A Sec: Ter:	**FAILURE TO CONTROL PARTS USED IN THE REACTOR PROTECTION SYSTEM RELATED TO LER 50-336/97-021-** At Unit 2, the licensee identified in 1997 that a failed, non-quality assurance (non-QA) lamp was installed in a QA circuit and had to the potential to affect the performance of safety-related circuits. The failure of the licensee to implement appropriate quality standards and measures for the selection and review of suitability of application of material, parts, equipment, and processes that are essential to the safety-related functions of systems and components is a violation of 10 CFR 50, Appendix B, Criterion III, "Design Control." This Severity Level IV violation is being treated as a Non-Cited Violation. (NCV 50-336/99-08-07) Licensee Event Report 50-336/97-021-00 is closed.
08/09/1999 Record ID: 78834	1999008-08	Pri: ENG Sec:	NRC	NCV	Pri: 4A Sec: Ter:	**FAILURE TO IDENTIFY SINGLE FAILURE VULNERABILITY IN THE AUXILIARY FEEDWATER SYSTEM WATER SUP** At Unit 2, the licensee identified in 1997 that a postulated single failure of a condenser hotwell makeup valve would cause a diversion of water from the condensate storage tank and impact the availability of sufficient water for the auxiliary feedwater system to perform its safety function. The licensee adequately determined the root cause of the single failure vulnerability and took appropriate corrective actions. The failure to establish appropriate design controls to ensure that safety-related equipment would function as assumed in the Unit 2 Final Safety Analysis Report is a violation of 10 CFR 50, Appendix B, Criteria III, "Design Control." This Severity Level IV violation is being treated as a Non-Cited Violation. (NCV 50-336/99-08-08) Licensee Event Report 50-336/97-025-00 is closed.

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08/09/1999	1999008-09	Pri: ENG	NRC	NCV	Pri: 4A	**INADEQUATE DESIGN OF THE 120 VOLT AC DISTRIBUTION SYSTEM RELATED TO LER 50-336/98-001-00**
Record ID: 78835		Sec:			Sec:	At Unit 2, the licensee identified in 1998 that, under some postulated high energy line break or seismic design basis accident conditions, the isolation of 120 volt vital AC electrical faults could not be ensured. The licensee appropriately reported and corrected the deficiency. The root cause evaluation was thorough, and the corrective actions were adequate. The failure to ensure that safety-related 120 volt vital AC equipment was designed in accordance with 10 CFR 50, Appendix B, Criterion III, "Design Control," to adequately respond to design basis accidents, is a violation of NRC requirements. This Severity Level IV violation is being treated as a Non-Cited Violation. (NCV 50-336/99-08-09) Licensee Event Report 50-336/98-001-00 is closed.
					Ter:	
08/09/1999	1999008-10	Pri: ENG	NRC	NCV	Pri: 4A	**INADEQUATE MAIN STEAM LINE BREAK ANALYSIS RELATED TO LER 50-336/98-007 & 01**
Record ID: 78836		Sec:			Sec:	At Unit 2, the licensee identified in 1998 that inadequate calculations of limiting power distributions had been performed for the Main Steam Line Break Analysis for cycle 13. As part of the corrective action, the licensee adequately reported the deficiency, requested a technical specification change and received a license amendment to resolve the deficiency. The failure to perform an adequate main steam line break analysis is a violation of 10 CFR 50 Appendix B, Criterion III, "Design Control." This Severity Level IV violation is being treated as a Non-Cited Violation. (NCV 50-336/99-08-10) Licensee Event Report 50-336/98-007-00 &-01 is closed.
					Ter:	
06/14/1999	1999006	Pri: ENG	NRC	NEG	Pri: 2A	**Unit 2 Manual Reactor Trip on May 25, 1999**
Record ID: 78688		Sec: OPS			Sec: 1B	On May 25, 1999, Unit 2 operators initiated a manual reactor trip, when a steam leak developed in the turbine building as a result of a transient in the feedwater heaters. Operator performance in isolating the steam leak and placing the plant in a stable condition was good. The feedwater heater transient was caused by improper setup of the feedwater heater level control valves. Inadequate procedural control was identified as the root cause, with inadequate initial design and inadequate corrective actions to address recurring level control problems identified as contributing causes. The transient developed into a steam leak because generic engineering guidance for selecting torque values was improperly applied in the selection of torque values for the feedwater heater relief valve flange fasteners. The NRC found that the corrective actions implemented prior to restart were adequate to address the direct causes of the feedwater heater level control problems and the subsequent steam leak. Longer term corrective actions described in LER 50-336/99-009-00 to address the root causes were also acceptable. Therefore, LER 50-336/99-009 -00 is closed. No violation of NRC regulatory requirements occurred. (Section U2.O1.3)
					Ter:	
06/14/1999	1999006-02	Pri: ENG	NRC	NCV	Pri: 4A	**Unit 2 (Closure of URI 98-208-02) Failure to Perform Design Reviews of Temporary Modifications**
Record ID: 78732		Sec:			Sec:	Unit 2 failed to perform design reviews of temporary modifications that were installed through plant procedures, which was a violation of 10 CFR 50, Appendix B, Criterion III, "Design Control." This Severity Level IV violation is being treated as a Non-Cited Violation , consistent with Appendix C of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on their having been entered into the corrective action program. The licensee's plan to complete the required design reviews prior to installation and as part of the biannual review of procedures was acceptable.
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03/05/1999 Record ID: 78735	1998219-01	Pri: ENG Sec:	NRC	NCV	Pri: 4A Sec: Ter:	**Unit 2 Number of Post-Accident Monitoring Channels was Inconsistent with FSAR** The NRC (URI 98-201-13) noted that the licensee's reduction of Regulatory Guide (RG) 1.97, Category 1 (safety-related and seismically qualified) post-accident monitoring indicators, from four channels to two channels, was technically adequate but inconsistent with the licensing basis reflected in FSAR Table 7.5-3. Table 7.5-3 identified four channels of Category 1 indication, meaning that the indication channels would be designed and qualified as safety-related from sensor to panel display. The licensee had two Category 1 channels and two nonsafety-related channels for a total of four channels. The licensee's failure to properly update FSAR Table 7.5-3 to reflect the reduction from four to two redundant RG 1.97 indication channels is a violation of 10 CFR 50.71(e), which requires, in part, that the licensee periodically update the FSAR.
03/05/1999 Record ID: 78738	1998219-02	Pri: ENG Sec: PLTSUP	NRC	NCV	Pri: 5C Sec: 4A Ter:	**Unit 2 Failed to Implement Adequate Corrective Actions in Revising RBCCW Rad Monitor Setpoint Calc** The NRC (Violation 98-202-05) noted that the flow rate assumed in the setpoint analysis for the RBCCW radiation monitor, RM-6038, was not assured by operating procedures and practice. In its response to the violation, the licensee stated that a calculation would be developed to determine new RM-6038 alarm setpoints. This revised calculation was inadequate because it did not consider the transport time of contamination from the contaminated train of RBCCW to the noncontaminated train of RBCCW. The transport time of contamination between the two trains was required to be considered in determining whether offsite release limits in 10 CFR Part 20 could be exceeded before RM-6038 would alarm.
03/05/1999 Record ID: 78741	1998219-03	Pri: ENG Sec:	NRC	NCV	Pri: 5C Sec: Ter:	**Unit 2 Failed to Implement Adequate Corrective Actions for CCW System Water Hammer Scenario** The NRC (URI 98-202-09) noted that LER 97-015-00 had identified a LOCA scenario that might result in severe voiding and water hammer of RBCCW piping to the containment air recirculation (CAR) coolers. The scenario involved a delayed manual start of the RBCCW pump if the automatic start somehow failed. The licensee had failed to study and address the delayed-start scenario. Later, the licensee determined that the piping would be overstressed if the manual restart scenario were to occur, but that the scenario would not result in catastrophic failure of RBCCW piping and containment penetrations. The failure to take appropriate corrective action for the delayed pump start scenario is considered to be a violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action."
04/19/1999 Record ID: 78641	1999005	Pri: ENG Sec:	NRC	POS	Pri: 2A Sec: Ter:	**Unit 2 Service Water Spool Pin Hole Leak** Unit 2 design, evaluation, and implementation of the temporary repair of a "pin-hole" leak of the "A" emergency diesel generator service water supply header spool No. SK4253 was acceptable and in accordance with NRC Generic Letter (GL) 90-05. The piping containing the flaw was operable with Temporary Modification No.2-99-008 until a replacement spool was installed. The licensee installed a fully qualified replacement spool prior to Unit 2 restart.
04/19/1999 Record ID: 78642	1999005-02	Pri: ENG Sec:	Licensee	NCV	Pri: 4A Sec: Ter:	**Unit 2 (Closure of URI 93-19-02 & LER 97-31) Failure to Meet Requirements for Protection From Pipe Whip** Unit 2 Final Safety Analysis Report (FSAR), Section 6.1.4.1.1, "Damage Protection Criteria," specifies the requirements to protect systems and structures from the results of pipe whip or pipe rupture. The failure of the equipment and structures discussed in LER 50-336/97-031-00 to meet the FSAR requirements is a violation of 10 CFR 50, Appendix B, Criterion III, Design Control. However, this violation is identified as a Non-Cited violation (NCV 50-336/99-05-02) in accordance with Section VII.B.1 of the NRC Enforcement Policy because the licensee identified the design deficiencies and took appropriate actions to correct the discrepancies.

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Date	Source	Functional Area	ID	Type	Template Codes	Item Title / Item Description
04/19/1999	1999005-03	Pri: ENG	Licensee	NCV	Pri: 4A	**Unit 2 Station Blackout Issues Identified in the Vectra Assessment**
Record ID: 78643		Sec:			Sec:	Unit 2, acceptably addressed the Station Blackout issues identified in the Vectra assessment. Therefore, EEI 50-336/96-201-28, Violation 50-336/02092, and Unit 2 SIL item number 31 are closed. The prepared analyses were reasonable; the calculations detailed, conservative, and in accordance with industry standards. However, the inspector found that dc voltage drop calculations were inadequate in that two incorrect assumptions were identified in shutdown voltage of the safety-related inverters and voltage drop in control cables. This is a violation of 10 CFR 50, Appendix B, Criterion III, "Design Control." This concern had limited safety impact because the battery currently has sufficient spare capacity to compensate for the potential deficiency. The licensee initiated action to evaluate the issues. Therefore, this Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Appendix C of the NRC Enforcement Policy.
					Ter:	
04/19/1999	1999005-04	Pri: ENG	Licensee	NCV	Pri: 4A	**Unit 2 (Closure of LER 97-06) Main Steam Line Break Analysis Did Not Include Auxiliary Feedwater Flow**
Record ID: 78644		Sec:			Sec:	Unit 2, final safety analysis report, Chapter 14, accident analysis for a main steam line break (MSLB) event initiated from low power was inadequate in that it did not consider the effects of auxiliary feedwater flow at the start of the accident which created the potential for peak containment pressure to exceed containment design pressure. The failure to establish an adequate MSLB analysis is a violation of 10CFR50, Appendix B, Criterion III, Design Control. However, the licensee identified this inadequacy and took adequate corrective actions to ensure containment pressure would remain below containment design pressure following a MSLB event. Therefore, this non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation consistent with Section VII.B.1 of the NRC Enforcement Policy.
					Ter:	
04/19/1999	1999005-05	Pri: ENG	Licensee	NCV	Pri: 4A	**Unit 2 (Closure of LER 97-15) Water Hammer and Thermally Induced Over Pressurization of Isolated Piping Se**
Record ID: 78645		Sec:			Sec:	Unit 2 effectively addressed the potential for water hammer and thermally induced overpressurization of isolated piping segments during postulated accident conditions. The failure of the licensee to consider the potential failure modes of isolated piping segments during the initial system design is a violation of 10CFR50, Appendix B, Criterion III, Design Control. This non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.
					Ter:	
04/19/1999	1999005-06	Pri: ENG	Licensee	NCV	Pri: 4A	**Unit 2 (Closure of LER 97-19) Inadequate Design Review and Testing of the 1992 Upgrade to the Engineered Sa**
Record ID: 78646		Sec:			Sec:	Unit 2 adequately addressed the potential for unexpected electro-magnetic interference (EMI) between the Automatic Test Initiation feature of the Engineered Safeguards Actuation System (ESAS) and the timing circuit for the shedding and sequencing of the emergency bus loads. The existence of the EMI signal which, under degraded voltage conditions, could have delayed the shedding and sequencing of the emergency loads on the electrical buses by as much as ten seconds, was the result of inadequate design reviews and/or testing during the 1992 upgrading of the ESAS. This Severity Level IV violation is being treated as a Non-Cited Violation (NCV 50-336/99-05-06), consistent with Appendix C of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations which have been entered into their corrective action program.
					Ter:	
04/19/1999	1999005-07	Pri: ENG	Licensee	NCV	Pri: 4A	**Unit 2 (Closure of LER 97-29) Failure to Maintain Main Steam and Feedwater Systems Within the Design Basis**
Record ID: 78647		Sec:			Sec:	Unit 2, failed to maintain the main steam and the feedwater systems within the design basis by failing to include required loads in pipe stress and pipe support calculations was a violation of 10CFR50, Appendix B, Criterion III, Design Control. However, the licensee identified these discrepancies with the design basis, and took adequate corrective actions to bring these two systems within the allowable established values in the code of record. Therefore, this licensee identified and corrected violation is being treated as a Non-Cited Violation.
					Ter:	

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04/19/1999 Record ID: 78648	1999005-08	Pri: ENG Sec:	Licensee	NCV	Pri: 4A Sec: Ter:	**Unit 2 (Closure of LER 98-12) Inadequate Loss of Normal Feedwater Event Analysis** Unit 2, accident analysis for a loss of normal feedwater (LONF) event was found by the licensee to be inadequate in that inaccurate and non-conservative assumptions were used for the initial steam generator water level and other parameters. This condition was a violation of 10CFR50, Appendix B, Criterion III, Design Control. However, the licensee identified the discrepancies, and took adequate corrective actions which provided an adequate margin to steam generator dryout following a LONF event. Therefore, this non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation, (NCV 50-336/99-05-08) consistent with Section VII.B.1 of the NRC Enforcement Policy. Significant Items List No. 55.5 is closed.
03/26/1999 Record ID: 78676	1999003	Pri: ENG Sec:	NRC	NEG	Pri: 1C Sec: Ter:	**Unit 2 Fire Protection - Timed Analysis for Alternate Shutdown** Unit 2 timeline analysis performed for alternate shutdown did not accurately reflect the conditions which could exist in that eventuality. Specifically, the analysis did not reflect the potential for the power operated relief valves, head vents, and letdown valves to remain open for up to five minutes after control room evacuation, due to bottle up panel cables being unprotected in fire area R-1.
03/26/1999 Record ID: 78680	1999003	Pri: ENG Sec:	NRC	NEG	Pri: 1C Sec: Ter:	**Unit 2 Fire Protection - Procedures** Unit 2 post-fire shutdown procedures, in some instances, contained problems related to sequencing of DC control power actions, and some actions were not well coordinated between the Unit 1 and Unit 2 procedures.
03/26/1999 Record ID: 78674	1999003	Pri: ENG Sec:	NRC	POS	Pri: 1C Sec: Ter:	**Unit 2 Fire Protection - Safe Shutdown Methodology and Program** Unit 2 safe shutdown methodology was found to be acceptable and the safe shutdown capability portion of the licensee's program was found to be adequate. The level of protection provided for redundant trains of post-fire shutdown systems satisfied the technical requirements of Appendix R to 10 CFR 50. The licensee's administrative controls with respect to configuration control/Appendix R compliance in the modification process were acceptable.
03/26/1999 Record ID: 78675	1999003	Pri: ENG Sec:	NRC	POS	Pri: 1C Sec: Ter:	**Unit 2 Fire Protection - Configuration Control and Maintenance** Unit 2 administrative controls with respect to configuration control/Appendix R compliance in the modification process were acceptable. The required maintenance and testing of the equipment supporting the Unit 1 electrical backfeed to Unit 2 is up to date and is being tracked.
03/26/1999 Record ID: 78678	1999003	Pri: ENG Sec:	NRC	POS	Pri: 1C Sec: Ter:	**Unit 2 Fire Protection - Fire Barrier and Quality Control** Unit 2 - A fire barrier penetration seal was installed and inspected in accordance with the installation procedure, and the manufacturer's installation instructions. The installers and quality control (QC) inspector were knowledgeable of the procedural requirements and were properly trained.

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03/26/1999 Record ID: 78682	1999003	Pri: ENG Sec:	NRC	POS	Pri: 1C Sec: Ter:	**Unit 2 Fire Protection - Audits** Unit 2 - Audits and assessments of the Fire Protection Program conducted since the autumn of 1996 have been effective in identifying deficiencies and areas for improvement. In addition, they have included followup of audit findings through the use of the corrective action program.
03/26/1999 Record ID: 78677	1999003	Pri: ENG Sec:	NRC	POS	Pri: 2A Sec: Ter:	**Unit 2 Fire Protection - Penetration Seals** Unit 2 has adequately implemented the commitment to perform inspections of silicone foam fire penetration seals for voids and material problems when the seals were repaired or replaced. The seal inspection conducted by the Fire Protection Engineer was professionally performed and no seal deficiencies were identified.
04/07/1999 Record ID: 78673	1999004	Pri: ENG Sec:	NRC	POS	Pri: 1C Sec: Ter:	**Unit 2 Operational Safety Team Inspection - Design Changes** Unit 2 design changes resolved the emergency core cooling system (ECCS) single failure vulnerabilities. Additionally, the aspects of the design changes reviewed, with the exception of the emergency operating procedures (EOP) changes, had been properly implemented. The licensee demonstrated that appropriate administrative controls were in place to ensure that the EOPs would be corrected prior to becoming effective. Significant Item List No. 53.1 is closed.
04/07/1999 Record ID: 78670	1999004	Pri: ENG Sec:	NRC	POS	Pri: 4B Sec: Ter:	**Unit 2 Operational Safety Team Inspection - Conduct of Engineering** Unit 2 planned and emergent engineering activities were managed well. Daily planning of issues at the morning meeting set the priorities of both the system and design engineering departments. Communication with and support to other departments were good. The identification, documentation and control of issues within the condition report (CR) system were good. Corrective actions associated with CRs and other open items were properly tracked within the action item tracking and trending system (AITTS).
04/07/1999 Record ID: 78672	1999004	Pri: ENG Sec:	NRC	POS	Pri: 4B Sec: Ter:	**Unit 2 Operational Safety Team Inspection - Engineering Procedures and Documentation** Unit 2's operability (OD) process was comprehensive, with ODs that were technically sound and documented an adequate basis for establishing operability of a degraded component or system. The licensee's program to maintain the accuracy of vendor manual information was being properly implemented. An adequate Unit 2 setpoint process was implemented and the Unit 2 Instrumentation and Control (I&C) setpoint specifications provided a clear definition of the program for the generation and documentation of safety-related, instrument and control setpoints. The commercial grade dedication and item equivalency evaluation programs were effective and performed appropriate evaluations to support plant restart. The team concluded that the operating experience program was functioning adequately to support restart. The backlog of reviews had been evaluated by the licensee to identify those issues requiring review before restart and appropriate priorities had been assigned to these issues. The majority of recently identified drawing issues have had minor safety significance. Current procedures and processes for updating operational critical drawings in the control room had been followed.

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04/07/1999 Record ID: 78671	1999004	Pri: ENG Sec:	NRC	POS	Pri: 4C Sec: Ter:	**Unit 2 Operational Safety Team Inspection - Engineering Support Facilities and Equipment** Unit 2's design control process was being properly implemented. The technical quality of changes was good and modification package content, including the 10CFR50.59 screening and safety reviews, are comprehensive. Post-modification testing accomplished the verification of important design change attributes. The use of a Quality Review Board has contributed to improvements in the quality of the engineering products. Engineering has been effective in resolving issues. As a result, the use of temporary modifications was minimal. The number of installed temporary modifications (TMs) was low and below the plant goal. The team concluded that the evaluation and control of temporary modifications was good and that the installed TMs had no adverse impact on safe plant operation. The licensee had adequate controls in place to ensure deferred work was properly evaluated. No deferred modifications were identified that would affect safe plant operation. The licensee had substantially improved the design and licensing basis of the control room heating ventilation and air conditioning (HVAC) system. Inconsistencies between the system design criteria contained in the final safety analysis report (FSAR), TS and the operating and surveillance procedures were eliminated. Single failure design errors were corrected. The system readiness review was thorough. The control room HVAC surveillance testing program was a strength.
03/01/1999 Record ID: 78728	1999002-04	Pri: ENG Sec:	Licensee	NCV	Pri: Sec: Ter:	**Unit 2 Failure to Maintain Design Configuration** Failure to maintain the design configuration of the safety-related piping systems is a violation of 10 CFR 50, Appendix B, Criterion III, Design Control. Problems were self-identified, corrected, and the risk was minimal.
01/05/2000 Record ID: 78906	1999014	Pri: PLTSUP Sec:	Licensee	NEG	Pri: 1C Sec: Ter:	**EVENT LOGS WERE PROPERLY MAINTAINED AND USED TO ANALYZE, TRACK, AND ADDRESS SAFEGUARDS E** Event logs were properly maintained and used to analyze, track, and address safeguards events. The logs indicated that there have been several breakdowns, involving the control of Safeguards information. This issue has been entered into the licensee's corrective action program.
01/05/2000 Record ID: 78905	1999014	Pri: PLTSUP Sec:	Licensee	NEG	Pri: 2A Sec: Ter:	**WEAKNESS WAS IDENTIFIED IN THE EFFECTIVENESS OF THE SECURITY COMMUNICATIONS SYSTEM** A weakness was identified in the effectiveness of the security communications system. This weakness has been entered in the licensee's corrective action program.
01/05/2000 Record ID: 78907	1999014	Pri: PLTSUP Sec:	NRC	NEG	Pri: 3B Sec: Ter:	**WEAKNESSES IN THE DOCUMENTATION OF TRAINING WERE IDENTIFIED** Weaknesses in the documentation of training were identified. These weaknesses have been entered into the licensee's corrective action program.

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01/05/2000 Record ID: 78908	1999014	Pri: PLTSUP Sec:	NRC	POS	Pri: 5A Sec: Ter:	**SECURITY PROGRAM AUDITS AND SELF-ASSESSMENTS EFFECTIVE IN RESOLVING POTENTIAL WEAKNESSE** Security Program audits were comprehensive in scope and depth, the audit findings were reported to the appropriate level of management, and the program was being properly administered. In addition, a review of the documentation applicable to the self-assessment program indicated that the program was being effectively implemented to identify and resolve potential weaknesses.
10/04/1999 Record ID: 78856	1999009	Pri: PLTSUP Sec:	NRC	POS	Pri: 3A Sec: Ter:	**EFFECTIVE IMPLEMENTATION OF RADIOLOGICAL CONTROLS** Radiological controls were effectively implemented during a Unit 2 forced outage in late September 1999.
10/04/1999 Record ID: 78857	1999009	Pri: PLTSUP Sec:	NRC	POS	Pri: 3A Sec: 1C Ter:	**DOSE ASSESSMENT PROGRAM** The internal exposure measurement and dose assessment program at Millstone is effective.
10/04/1999 Record ID: 78858	1999009	Pri: PLTSUP Sec:	NRC	POS	Pri: 5A Sec: 5B Ter: 5C	**SELF ASSESSMENT OF RADIATION PROTECTION** The RP program has an active oversight and self-assessment program that engages problems in an effective manner.
10/08/1999 Record ID: 78859	1999011	Pri: PLTSUP Sec:	NRC	POS	Pri: 1C Sec: Ter:	**THE HUMAN SERVICES ORGANIZATION'S "PEOPLE TEAM" EFFECTIVELY FOCUSED ON EMERGING ISSUES AN** The Human Services Organization's "People Team" effectively focused on emerging issues and coordinated follow-up actions. Action was taken in a timely manner to evaluate and address potential safety conscious work environment issues. The "People Team" made improvements in establishing accountability for and tracking of actions. The Core Group and the targeted workplace surveys were effective tools for monitoring the safety conscious work environment at Millstone. The survey reports provided a thorough evaluation of the survey results. However, the recommendations did not always result in timely, proactive corrective actions. Team interviews found that site employees were familiar with programs and processes for handling concerns, and they would be willing to raise nuclear safety concerns. The Safety Conscious Work Environment (SCWE) department used the SCWE Case Process appropriately to address significant concerns based on established criteria. Action plans were well developed, and planned actions and assessment activities appeared to have been implemented in a timely manner. The team identified discrepancies in the documentation and tracking of actions and assessment activities, most notably in older case files. The Executive Review Board process was thorough and functioned as designed to ensure upcoming personnel actions were appropriate, and not the result of harassment, intimidation, discrimination, or retaliation.

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10/08/1999	1999011	Pri: PLTSUP	NRC	POS	Pri: 1C	**THE ECOP WAS EFFECTIVE IN PROVIDING OVERSIGHT OF THE SCWE AT MILLSTONE**
Record ID: 78860		Sec:			Sec:	The Employee Concerns Oversight Panel (ECOP) was effective in providing oversight of the safety conscious work environment at Millstone. The team determined that the ECOP quarterly report was comprehensive and provided detailed information that site management could use to assess the safety conscious work environment at Millstone.
					Ter:	
10/08/1999	1999011	Pri: PLTSUP	NRC	POS	Pri: 1C	**THE ECP DEPARTMENT WAS ADEQUATELY STAFFED AND WAS EFFECTIVE IN HANDLING EMPLOYEE CONCER**
Record ID: 78861		Sec:			Sec:	The Employee Concerns Program (ECP) department was adequately staffed and was effective in handling employee concerns. Generally, key performance indicators (KPIs) showed positive or steady trends and performance in the ECP area. However, two KPIs, the backlog of cases under investigation and the backlog of open ECP corrective actions, showed negative trends. To help reduce the backlog of cases under investigation, the licensee was training an individual to become an ECP investigator. However, site management attention is warranted to address the increasing backlog of ECP corrective actions. The ECP department continued to perform thorough investigations. The quality of the ECP case files was high, with good investigative work noted. In all but one ECP case file, the investigations properly supported the conclusions. The ECP department reopened this investigation. The ECP department did not begin an investigation into a potential harassment, intimidation, retaliation, and discrimination (HIRD) issue until eight weeks after they had received the concern. The licensee is considering enhancing their process to prevent recurrence.
					Ter:	
10/08/1999	1999011	Pri: PLTSUP	NRC	POS	Pri: 1C	**LHC OBSERVED THAT THERE HAS BEEN IMPROVEMENT IN MOST AREAS SINCE JUNE 1999**
Record ID: 78862		Sec:			Sec:	Little Harbor Consultants (LHC) observed that there has been improvement in most areas since June 1999. All programs and policies put in place to enhance site performance with respect to a safety conscious work environment are functioning reasonably well.
					Ter:	
10/08/1999	1999011	Pri: PLTSUP	NRC	POS	Pri: 1C	**OVERALL IMPROVEMENT IN THE SAFETY CONSCIOUS WORK ENVIRONMENT**
Record ID: 78909		Sec:			Sec:	The team observed a generally healthy safety conscious work environment at Millstone. We noted overall improvement in most areas since the NRC's previous assessment in June 1999. Although the team found some minor deficiencies, these deficiencies did not detract from the overall effectiveness of the programs.
					Ter:	
08/09/1999	1999008	Pri: PLTSUP	NRC	NEG	Pri: 1C	**Security Personnel Turnover**
Record ID: 78722		Sec:			Sec:	There has been an increase in the turnover rate in the security force sergeant ranks causing a shortage of sergeants to man regulatory required posts. The inspection determined that all required posts have been properly manned, overtime being worked by the sergeants was within prescribed guidelines and management was taking action to train and qualify additional sergeants to increase staffing levels.
					Ter:	
08/09/1999	1999008	Pri: PLTSUP	NRC	POS	Pri: 1C	**Fitness for Duty Programs**
Record ID: 78723		Sec:			Sec:	The fitness-for-duty program was being implemented in accordance with the licensee's procedures and regulatory requirements.
					Ter:	

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08/09/1999 Record ID: 78721	1999008	Pri: PLTSUP Sec:	NRC	POS	Pri: 1C Sec: 5B Ter:	**Unit 3 External Radiological Controls** The licensee is continuing to conduct an aggressive and comprehensive event review of a 7.04 rem exposure, involving an individual's personnel TLD device, to determine if the exposure represents an actual exposure to an individual or was the result of tampering with the individual's TLD, or other deliberate misconduct. The licensee's event review effort was conducted by knowledgeable personnel, and was comprehensive in scope and depth.
04/19/1999 Record ID: 78650	1999005	Pri: PLTSUP Sec:	NRC	POS	Pri: 1C Sec: Ter:	**Offsite Dose Calculation Manual Requirements for Reporting Effluent Releases** Offsite Dose Calculation Manual (ODCM) requirements for reporting effluent releases and projected doses to the public were effectively implemented. The ODCM contained sufficient specification, information, and instruction to acceptably implement and maintain the radioactive liquid and gaseous effluent control programs.
04/19/1999 Record ID: 78651	1999005	Pri: PLTSUP Sec:	NRC	POS	Pri: 1C Sec: Ter:	**Radiological Environmental Monitoring Program** The radiological environmental monitoring program (REMP) was effectively implemented in accordance with regulatory requirements. The licensee effectively performed sample collection activities, conducted the land use census, and maintained and calibrated the automatic sampling equipment and analysis equipment according to the appropriate procedures. The procedures were technically correct, but needed some administrative revision to reflect program oversight and implementation responsibilities. The most recent audit of the REMP was detailed and thorough and covered every aspect of the REMP. The audit was sufficient to effectively evaluate implementation and effectiveness of the REMP. The recommendations for improvement were appropriate and corrective actions for areas for improvements were appropriate. The REMP quality assurance program was effectively maintained and implemented in accordance with regulatory requirements. The environmental laboratory continued to implement excellent QA/QC programs for the REMP, provide effective validation of analytical results, and conduct the QA/QC programs in accordance with procedures that reflect industry standards and methods. The programs were capable of ensuring independent checks on precision and accuracy of the measurements of radioactive material in environmental media.
04/19/1999 Record ID: 78654	1999005	Pri: PLTSUP Sec:	NRC	POS	Pri: 1C Sec: Ter:	**Radiation Monitor System - Calibrations and Reliability** The licensee established, implemented, and maintained an effective Radiation Monitoring System program with respect to electronic calibrations, radiological calibrations, system reliability and tracking and trending.
04/19/1999 Record ID: 78655	1999005	Pri: PLTSUP Sec:	NRC	POS	Pri: 1C Sec: Ter:	**Ventilation System Radiological Monitoring** The licensee established, implemented, and maintained an effective ventilation system surveillance program with respect to charcoal adsorption surveillance tests, high efficiency particulate filter mechanical efficiency tests, and air flow rate tests.

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04/19/1999 Record ID: 78652	1999005	Pri: PLTSUP Sec:	NRC	POS	Pri: 2B Sec: Ter:	**Meteorological Monitoring Program Was Effective** The meteorological monitoring program was effectively maintained and implemented in accordance with regulatory requirements. The licensee's performance with regard to maintaining the meteorological monitoring instrumentation reliability was also effective. The licensee improved meteorological monitoring instrumentation through program ownership and better communication, tracking areas for improvement, and correcting previous problems.
04/19/1999 Record ID: 78734	1999005-13	Pri: PLTSUP Sec:	NRC	URI	Pri: 5C Sec: 4B Ter:	**Unit 2 (Closure of URI 90-18-05) Post Accident Sampling System** At Unit 2, the licensee adequately demonstrated the operation of the PASS. Sample results met the appropriate acceptance criteria and, although the licensee could not consistently meet the total dissolved gas (TDG) acceptance criteria, TDG concentration results were marginally outside the acceptable value. The licensee is continuing to assess the method for retrieving and analyzing a TDG sample for better accuracy. Revised/approved PASS procedures were found to be detailed, technicians were retrained, equipment deficiencies were corrected and the system was repeatedly tested. The licensee adequately demonstrated an Emergency PASS drill and met the time requirement for obtaining post-accident sample results within 3 hours. An unresolved item is being opened to allow further NRC evaluation of the licensee's method for assessing core damage without the use of a TDG analysis and to review the 10CFR50.54(q) evaluation for determining whether or not the procedure change decreased the effectiveness of the E-Plan.
03/26/1999 Record ID: 78681	1999003	Pri: PLTSUP Sec: OPS	NRC	POS	Pri: 1C Sec: Ter:	**Unit 2 Fire Protection -Training, Shift Manning and Augemented Coverage** Unit 2 post-fire safe shutdown operator training and qualification tasks were comprehensive, and reflected the current approved revision of the safe shutdown procedures. The tasks covered major steps in the procedures in sufficient detail to ensure the adequacy of the operators' level of understanding. Augmented shift manning in place was adequate for the performance of post-fire shutdown activities. The CONVEX procedure and manning appeared to provide adequate controls for deenergizing the offsite feeds to the electrical distribution system.

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Legend

Type Codes:

BU	Bulletin
CDR	Construction
DEV	Deviation
EEI	Escalated Enforcement Item
IFI	Inspector follow-up Item
LER	Licensee Event Report
LIC	Licensing Issue
MISC	Miscellaneous
MV	Minor Violation
NCV	NonCited Violation
NEG	Negative
NOED	Notice of Enforcement Discretion
NON	Notice of Non-Conformance
OTHR	Other
P21	Part 21
POS	Positive
SGI	Safeguard Event Report
STR	Strength
URI	Unresolved Item
VIO	Violation
WK	Weakness

Template Codes:

1A	Normal Operations
1B	Operations During Transients
1C	Programs and Processes
2A	Equipment Condition
2B	Programs and Processes
3A	Work Performance
3B	KSA
3C	Work Environment
4A	Design
4B	Engineering Support
4C	Programs and Processes
5A	Identification
5B	Analysis
5C	Resolution

ID Codes:

NRC	NRC
Self	Self-Revealed
Licensee	Licensee

Functional Areas:

OPS	Operations
MAINT	Maintenance
ENG	Engineering
PLTSUP	Plant Support
OTHER	Other

EEIs are apparent violations of NRC Requirements that are being considered for escalated enforcement action in accordance with the "General Statement of Policy and Procedure for NRC Enforcement Action" (Enforcement Policy), NUREG-1600. However, the NRC has not reached its final enforcement decision on the issues identified by the EEIs and the PIM entries may be modified when the final decisions are made.

URIs are unresolved items about which more information is required to determine whether the issue in question is an acceptable item, a deviation, a nonconformance, or a violation. A URI may also be a potential violation that is not likely to be considered for escalated enforcement action. However, the NRC has not reached its final conclusions on the issues, and the PIM entries may be modified when the final conclusions are made.

Dockets (MILL2), Item Type (Compliance,Followup,Other), From 01/16/1999 To 01/31/2000

Attachment 2

Mr. Stephen E. Scace, Director
Nuclear Oversight and Regulatory Affairs
c/o Mr. D. A. Smith, Manager - Regulatory Affairs
Northeast Nuclear Energy Company
P.O. Box 128
Waterford, Connecticut 06385

SUBJECT: PLANT PERFORMANCE REVIEW - MILLSTONE STATION

The purpose of this letter is to communicate our assessment of your performance and to inform you of our planned inspections at your facility. On February 24, 2000, we completed a Plant Performance Review (PPR) of Millstone Station. We conduct these reviews to develop an integrated overview of the safety performance of each operating nuclear power plant. We use the results of the PPR in planning and allocating inspection resources and as inputs to our senior management meeting (SMM) process. This PPR evaluated inspection results and safety performance information for the period from January 16, 1999, through January 31, 2000, but emphasized the last six months to ensure that our assessment reflected your current performance. Our last full and mid-cycle PPR reviews of Millstone Station were provided to you in letters dated April 9, 1999, and September 30, 1999. In our May 3, 1999, letter following the April 1999 Senior Management Meeting, we indicated that the Millstone Units 2 and 3 require enhanced monitoring as agency and regional focus plants, respectively. A Millstone Assessment Panel was established to guide the enhanced NRC oversight of the Millstone units as described in our August 20, 1999, letter.

The NRC has been developing a revised reactor oversight process that will replace our existing inspection and assessment processes, including the PPR, the SMM, and the Systematic Assessment of Licensee Performance (SALP). We recently completed a pilot program for the revised reactor oversight process at nine participating sites and are making necessary adjustments based on feedback and lessons learned. We plan to begin initial implementation of the revised reactor oversight process industry-wide, including your facility, on April 2, 2000.

This PPR reflects continued process improvements as we make the transition into the revised reactor oversight process. We have considered the historical performance indicator data that you submitted in January 2000 in conjunction with the inspection results in assessing your performance. The results of this PPR were used to establish the inspection plan in accordance with the new risk-informed inspection program (consisting of baseline and supplemental inspections). Although this letter incorporates some terms and concepts associated with the new oversight process, it does not reflect the much broader changes in inspection and assessment that will be evident after we have fully implemented our revised reactor oversight process.

During the last six months, the Millstone Unit 2 remained at power with the exception of two manual reactor trips caused by equipment problems associated with the feedwater heater drain

system and one forced shutdown caused by a misaligned control rod. Millstone Unit 3 remained at power during the entire assessment period, except for the sixty day period during which a refueling outage was conducted.

Our PPR review of Millstone determined that the improvement in operational performance, which we noted in the mid-cycle PPR review, was sustained. In particular, emergent equipment and operational issues had minimal impact on the performance at Unit 3. Although equipment problems had a greater impact on Unit 2, sustained operation for two four-month periods was achieved since plant startup in May 1999. Operators responded well to emergent equipment problems and displayed a conservative approach to plant operations.

While the overall corrective action processes demonstrated improvement, the engineering resolution of some equipment problems was not fully effective. Some examples include a recurrent problem with water intrusion into the bearing lube oil of an auxiliary feed water pump at Unit 2 and recurrent design control problems with the cubicle sump pumps for the recirculation spray system at Unit 3. Although the NRC identified a number of instances in which problems were not identified through condition reports at Unit 2, we noted that these problems were generally not significant nor pervasive, and that the threshold for problem identification remained low.

A generally healthy safety conscious work environment existed at Millstone. Appropriate programs and processes have been established to address employee concerns and to monitor and evaluate the safety conscious work environment. Although some deficiencies were found, they did not detract from the overall effectiveness of the programs and processes. Site employees were familiar with programs and processes for handling concerns, and indicated a willingness to raise nuclear safety concerns. However, the NRC will continue to monitor the safety conscious work environment at Millstone, including the review of the findings from the next Little Harbor Consultant report, to determine what further NRC inspection in this area is warranted.

We plan to conduct only baseline inspections at your facility beginning in April 2000 and as noted in the attached inspection plan. An initiative inspection to review some modifications, relating to the impact of decommissioning activities at Unit 1 upon the Unit 2 and Unit 3 alternate ac power supplies, is planned for March 2000.

Enclosure 1 contains a historical listing of plant issues, referred to as the Plant Issues Matrix (PIM), that were used during this PPR process to arrive at our integrated view of your performance trends. The PIM for this assessment is grouped by the prior SALP functional areas of operations, maintenance, engineering and plant support, although the future PIM will be organized along the cornerstones of safety as described in the revised reactor oversight process. The attached PIM includes items summarized from inspection reports or other docketed correspondence between the NRC and Northeast Nuclear Energy Company regarding Millstone Station. We did not document all aspects of licensee programs and performance that may be functioning appropriately. Rather, we only documented issues that we believe warrant management attention or represent noteworthy aspects of performance. In addition, the PPR may also have considered some predecisional and draft material that does not appear in the attached PIM, including observations from events and inspections that had occurred since our

last inspection report was issued, but had not yet received full review and consideration. We will make this material publicly available as part of the normal issuance of our inspection reports and other correspondence.

Enclosure 2 lists our planned inspections for the period April 2000 through March 2001 at Millstone Station to allow you to resolve scheduling conflicts and personnel availability in advance of our inspector arrival onsite. The inspection schedule for the latter half of the period is more tentative and may be adjusted in the future due to emerging performance issues at Millstone Station or other Region I facilities. Routine resident inspections are not listed due to their ongoing and continuous nature.

We will inform you of any changes to the inspection plan. If you have any questions, please contact me at (610) 337-5129.

Sincerely,

James C. Linville, Director
Millstone Inspection Directorate

Docket Nos. 50-336; 50-423
License No. DPR-65; NPR-49

Enclosures:
1. Plant Issues Matrix
2. Inspection Plan

DOCUMENT NAME: S:\February 2000 PPR\Millstone\MS 2000 Full PPR Letter-draft.wpd
To receive a copy of this document, indicate in the box: "C" = Copy without attachment/enclosure "E" = Copy with attachment/enclosure "N" = No copy

OFFICE	ORA/MID		ORA/MID		ORA/MID							
NAME	RUrban		DLew		JLinville							
DATE	9/ /99		9/ /99		9/ /99							

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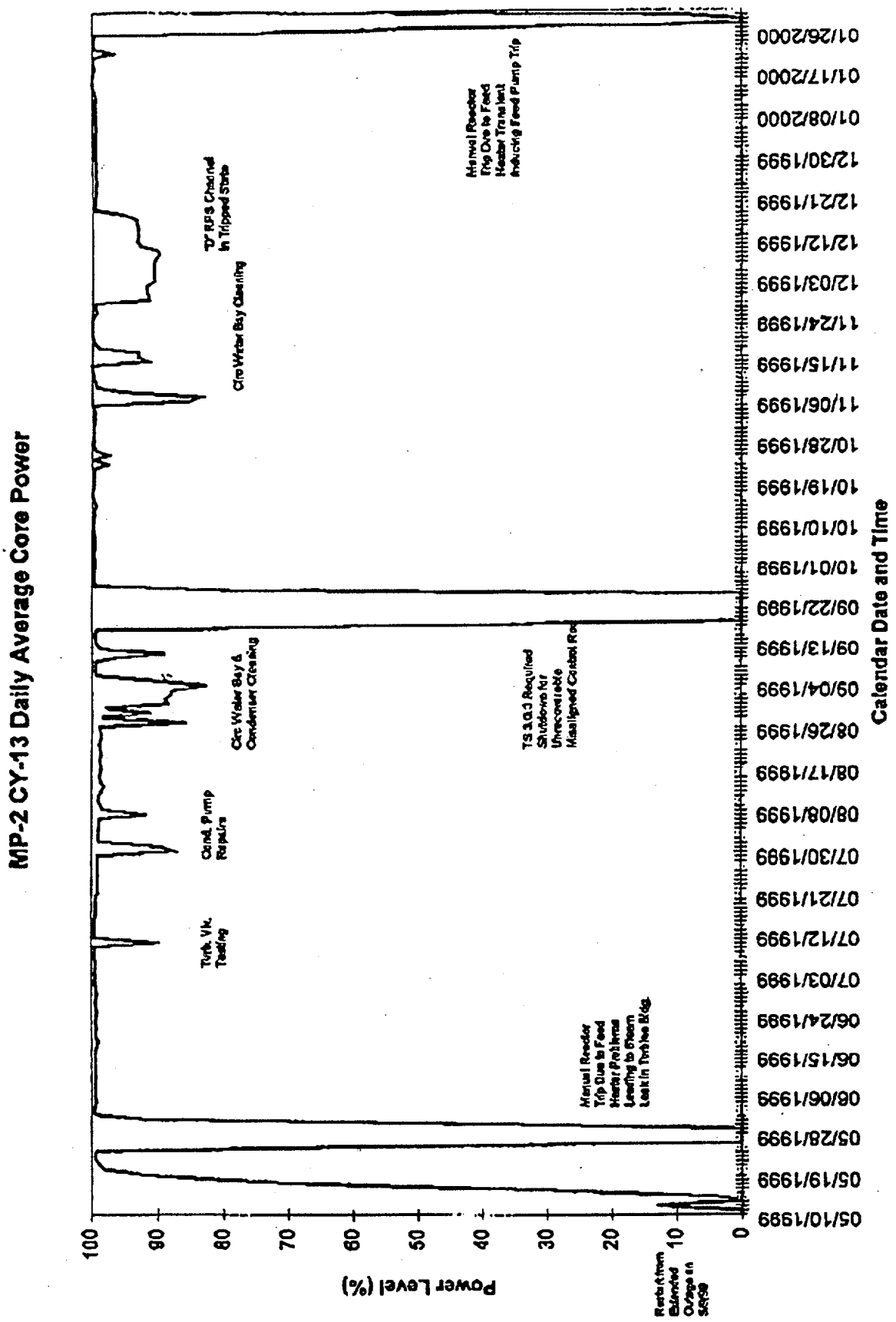
Millstone 2
Inspection / Activity Plan
04/01/2000 - 03/31/2001

Units	Inspection Activity	Title	No. of Staff on Site	No. assigned to Procedure	Planned Dates Start	Planned Dates End	Inspection Type
	71121.01	- OCCUPATIONAL RAD SAFETY & PI VERIFICATIO	1				
2	IP 71121.01	Access Control to Radiologically Significant Areas		1	04/10/2000	04/14/2000	Other Routine
2	IP 71151	Performance Indicator Verification		1	04/10/2000	04/14/2000	Other Routine
	71121.02	- OCCUPATIONAL RAD SAFETY - OUTAGE	1				
2	IP 71121.02	ALARA Planning and Controls		1	05/22/2000	05/26/2000	Other Routine
	71111.08	- ISI - UNIT 2	1				
2	IP 71111.08	Inservice Inspection Activities (I,B)		1	05/22/2000	05/25/2000	Other Routine
	71130	- SECURITY	1				
2	IP 71130.01	Access Authorization		1	06/05/2000	06/09/2000	Other Routine
2	IP 71130.02	Access Control		1	06/05/2000	06/09/2000	Other Routine
	71111.17	- U2/U3 MODS & 50.59	5				
2	IP 71111.02	Changes to License Conditions and Safety Analysis Report (M,B)		4	06/12/2000	06/16/2000	Other Routine
2	IP 71111.17	Permanent Plant Modifications (M,B)		4	06/12/2000	06/16/2000	Other Routine
	8/7 EXAM	- INIT LIC EXAM	3				
2	U01250	MILLSTONE 2 INITIAL EXAM		3	07/10/2000	07/14/2000	Not Applicable
2	U01250	MILLSTONE 2 INITIAL EXAM		3	08/07/2000	08/11/2000	Not Applicable
	71121.03	- OCCUPATIONAL RAD SAFETY - INSTRUMENTATIO	1				
2	IP 71121.03	Radiation Monitoring Instrumentation		1	08/21/2000	08/25/2000	Other Routine
	71111.21	- U2 SSFI	5				
2	IP 71111.21	Safety System Design and Performance Capability (M)		1	09/18/2000	09/22/2000	Other Routine
2	IP 71111.21	Safety System Design and Performance Capability (M)		1	10/02/2000	10/06/2000	Other Routine
	71122.03	- PUBLIC RAD SAFETY - REMP	1				
2	IP 71122.03	Radiological Environmental Monitoring Program		1	10/02/2000	10/06/2000	Other Routine
	71111.12	- MAINT RULE	3				
2	IP 71111.12	Maintenance Rule Implementation (I,M,B)		3	10/23/2000	10/27/2000	Other Routine
	71122.02	- PUBLIC RAD SAFETY - RADWASTE	1				
2	IP 71122.02	Radioactive Material Processing and Shipping		1	11/13/2000	11/17/2000	Other Routine
	71111.11	- LIC OPER RQ INSP	3				
2	IP 71111.11	Licensed Operator Requalification (M,B)		3	12/04/2000	12/08/2000	Other Routine
	71152	- PI&R	5				
2	IP 71152	Identification and Resolution of Problems		1	01/29/2001	02/02/2001	Other Routine
2	IP 71152	Identification and Resolution of Problems		1	02/12/2001	02/16/2001	Other Routine
	71130.03	- SECURITY - RESPONSE	3				
2	IP 71130.03	Response to Contingency Events		3	02/12/2001	02/16/2001	Other Routine

This report does not include INPO and OUTAGE activities.
This report shows only on-site and announced inspection procedures.

FEB-23-2000 11:32 DRP 610 337 5349 P.02/02

Attachment 3



Attachment 4

MILLSTONE UNIT 2 STRATEGY

CONCERN: The NRC identified several instances where the licensee staff failed to initiate condition reports, which resulted in untimely or inadequate corrective actions. Examples were water intrusion into the bearing oil of a Unit 2 auxiliary feedwater pump and air entrapment in the piping from the Unit 2 recirculation sump. In both cases, safety systems were significantly degraded. Other failures resulted in the untimely initiation of operability determinations. In addition, a condition report was not written when the operators recorded data at a higher power level than specified in a procedure during a Unit 2 reactor startup.

(Response by licensee) Although condition reports were initiated for specific issues, the only broader action the licensee has implemented was the issuance of a memorandum reaffirming their expectations for condition report initiation. In several examples, the deficiency was entered into their work control process but not their corrective action process and therefore, the impact on system operability was not assessed. The licensee is in the process of revising their corrective action process to use a single form to enter deficiencies.

(NRC Strategy) A 40500 initiative inspection was performed the week of January 31, 2000. Preliminary results reveal several additional examples of failing to initiate condition reports, although the new issues were of lesser safety significance. Resident inspectors will continue to monitor this area.

CONCERN: Engineering resolutions of some long-standing and recurrent equipment problems were ineffective. These equipment problems included the water intrusion in the bearing oil of a Unit 2 auxiliary feedwater pump, the degradation of a reactor protection system selector switch that resulted in a drifting setpoint, and feedwater heater level control problems that on two occasions resulted in a plant transient and a subsequent manual reactor trip. Other engineering issues involve the impact upon the Units 2 and 3 plant configuration, as a result of Unit 1 decommissioning activities.

(Response by licensee) The licensee has completed corrective actions or has corrective measures planned to address the design concerns that are listed. The licensee has reinforced the need for the station design control and management approval processes (e.g., PORC/SORC) to continue to monitor the effects of decommissioning activities at Unit 1 upon the configuration and operation of Units 2 and 3. Also, senior licensee management is aware of the need to provide more emphasis on the system engineer's role in work priorities involving their systems.

(NRC Strategy) The week of January 31, 2000, a 40500 inspection assessed engineering backlogs for additional examples of long-standing recurrent equipment problems to assess the adequacy of licensee plans to address the concerns. Preliminary results show one additional example involving the fact that the turbine bypass system did not appear to operate in accordance with the FSAR during plant trips causing the steam generator safety valves to lift. Resident inspectors will continue to monitor this area. Also, a Region I specialist inspection of some modifications, relating to the impact of decommissioning activities at Unit 1 upon the Unit 2 and Unit 3 alternate ac power supplies, has been recommended by the Millstone Assessment Panel for the first quarter of CY 2000.

CONCERN: Large engineering and corrective action backlogs for Unit 2 and the competition for resources between emerging work and existing item closeout activities present a continuing

challenge to the licensee. As site-wide resources focus on the April 2000 refueling outage at Unit 2, this further challenges their backlog reduction efforts.

(Response by licensee) The licensee has docketed their Backlog Management Plan that provides commitments regarding the completion of backlogged engineering and maintenance items. The licensee is in the process of finalizing the list of maintenance and engineering items for the upcoming Unit 2 refueling outage.

(NRC Strategy) Preliminary results of the 40500 inspection the week of January 31, 2000, indicate that appropriate focus was being placed on working off the backlog and that items were being appropriately prioritized and scheduled. Resident inspectors and the Millstone Assessment Panel will continue to monitor licensee progress in reducing the large engineering and corrective action backlogs.

CONCERN: The licensee's evaluation of their off-year emergency preparedness exercise on September 15, 1999, identified a failure of five exercise objectives. These objectives were accident projection, emergency classification, notification of onsite/offsite responders, communications between facilities, and magnitude of release components. However, the licensee concluded that the health and safety of the public would have been protected.

(Response by licensee) A Level 1 condition report, requiring root cause analysis, was initiated to document the findings and effect corrective actions. This area was reported as a white area in the licensee's Millstone Station Performance Indicator Report (October 1999); but, after the implementation of corrective measures, this was upgraded to green in January 2000. An emergency planning drill was conducted on February 9, 2000.

(NRC Strategy) An inspection of the licensee's EP Program area, with emphasis on their corrective actions, is scheduled prior to the full-participation EP drill. The licensee's full-participation EP drill is scheduled for March 15, 2000.

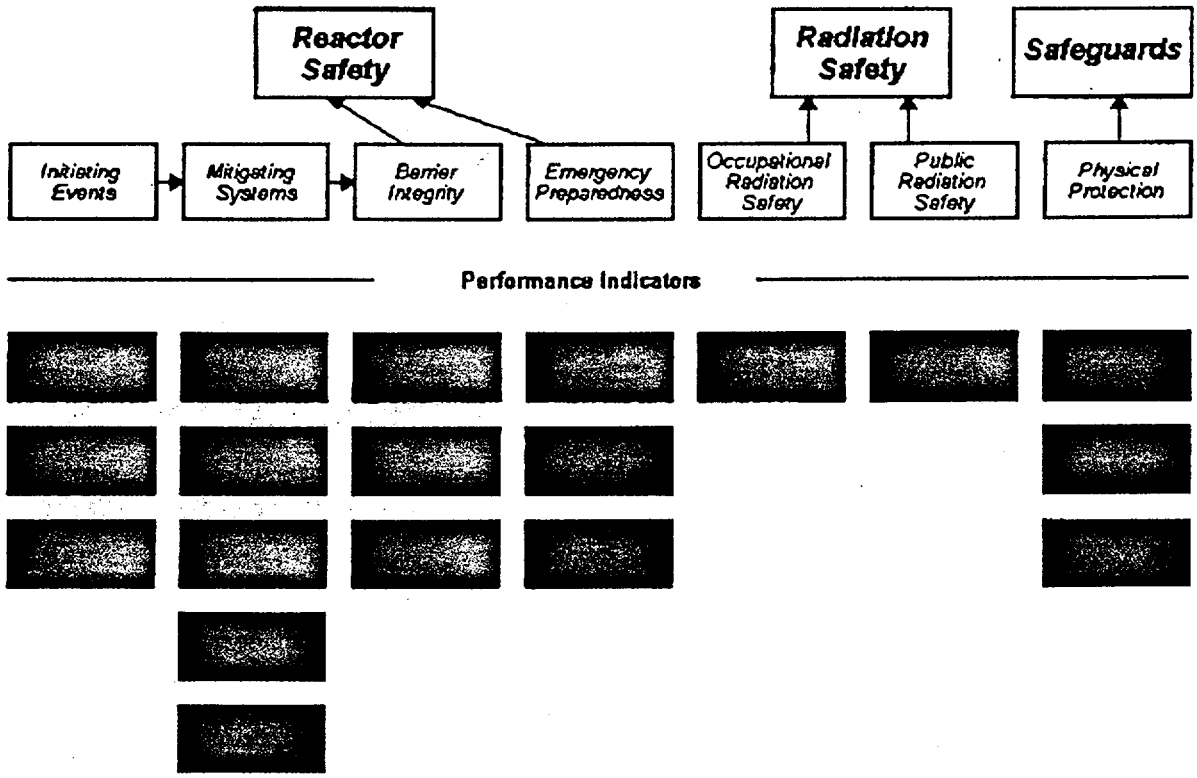
CONCERN: Challenges to a healthy safety conscious work environment may exist as a result of a continuing changes at Millstone. This includes Entergy management of the decommissioning of Unit 1, planned reductions in contractor and licensee positions through year 2000, consideration of a revised pay structure, and the planned sale of Millstone. Although there is no evidence to support that the work environment is being challenged, the licensee needs to remain diligent in monitoring and maintaining the safety conscious work environment during these changes.

(Response by Licensee) The licensee's Human Services organization, in coordination with other organizations, recognizes these challenges and initiated actions to mitigate the potential impact on the safety conscious work environment. Enhanced retirement packages have been tendered and the planned reduction of personnel has considered individual department impact, by staggering the planned acceptance of retirements through the year 2000. Another independent assessment of the safety conscious work environment by Little Harbor Consultants is planned for the second quarter of 2000. Senior licensee management is working with the state DPU to minimize adverse impact on the station that could result from the station bidding and sale process.

(NRC Strategy) The NRC will monitor the safety conscious work environment through reviews of future Little Harbor Reports, resident observations and other NRC processes. Based upon these observations, the need for NRC inspections using procedure 40001 will be assessed.

Attachment 5

MILLSTONE 2
4Q/1999 Performance Summary



Legend:
(G) = Green
(W) = White
(Y) = Yellow
(R) = Red
(T) = Thresholds under development/review
(I) = Insufficient data to calculate PI
(N) = Not applicable

Note: Inspection findings & additional assessment information will be posted when available.

Attachment 6

September 30, 1999

Mr. R. P. Necci, Vice President
Nuclear Oversight and Regulatory Affairs
c/o Mr. D. A. Smith, Manager - Regulatory Affairs
Northeast Nuclear Energy Company
PO Box 128
Waterford, CT 06385

SUBJECT: MID-CYCLE PLANT PERFORMANCE REVIEW (PPR) - MILLSTONE STATION

Dear Mr. Necci:

On September 16, 1999, the NRC staff completed the mid-cycle Plant Performance Review (PPR) of Millstone. The staff conducted these reviews for all operating nuclear power plants to integrate performance information and to plan inspection activities at your facility through March 2000. The focus of this performance review was to identify changes in performance over the past six months, and to allocate inspection resources accordingly. The results of the Millstone full PPR were provided to you in a letter dated April 9, 1999. In our May 3, 1999 letter following the April 1999 Senior Management Meeting, we indicated that the Millstone Units 2 and 3 require enhanced monitoring as agency and regional focus plants respectively. A Millstone Assessment Panel was established to guide the enhanced NRC oversight of the Millstone units as described in our August 20, 1999 letter.

Our mid-cycle PPR review of Millstone determined that your performance was generally consistent with that described in our April 9 and May 3, 1999 letters, but operational performance of both units has improved. In July 1999, we completed a team inspection which concluded that the safety conscious work environment at Millstone was generally healthy and that your staff was effective in identifying, resolving and preventing equipment problems and personnel performance issues. However, the NRC identified several recent instances in which condition reports were not initiated, resulting in untimely or inadequate corrective actions. Examples included water intrusion into the bearing oil of a Unit 2 auxiliary feedwater pump, air entrapment in the Unit 2 emergency core cooling system sump recirculation piping, and inoperable Unit 3 recirculation spray system room sump pumps. Based on these observations, we are planning to examine problem identification and corrective action program implementation as part of previously planned inspections of the safety conscious work environment, work control process improvements and backlog reduction efforts. Further, ongoing issues concerning the ability to adequately use the post accident sampling system will be the subject of an NRC initiative inspection. In addition, as is the case with all pressurized water reactors, we plan to follow up on your response to Generic Letter 98-02, "Loss of Coolant Inventory and Associated Potential for Loss of Emergency Mitigation Functions While in a Shutdown Condition."

Enclosure 1 contains a historical listing of plant issues, referred to as the Plant Issues Matrix (PIM), that were considered during this PPR process to arrive at an integrated review of licensee performance trends. The PIM includes items summarized from inspection reports or other

docketed correspondence between the NRC and Northeast Nuclear Energy Company from October 1998 through September 1999. As noted above, greater emphasis was placed on those issues identified in the past six months during this performance review. The NRC does not attempt to document all aspects of licensee programs and performance that may be functioning appropriately. Rather, the NRC only documents issues that the NRC believes warrant management attention or represent noteworthy aspects of performance. In addition, the PPR may also have considered some predecisional and draft material that does not appear in the attached PIM, including observations from events and inspections that had occurred since the last NRC inspection report was issued, but had not yet received full review and consideration. This material will be placed in the PDR as part of the normal issuance of NRC inspection reports and other correspondence.

This letter advises you of our plans for future inspection activities at your facility so that you will have an opportunity to prepare for these inspections and to provide us with feedback on any planned inspections that may conflict with your plant activities. Enclosure 2 details our inspection plan from September 1999 through March 2000 to coincide with the scheduled implementation of the revised reactor oversight process in April 2000. The rationale or basis for each regional initiative inspection added since the last PPR is discussed above so that you are aware of the reason for emphasis in these program areas. Resident inspections are not listed due to their ongoing and continuous nature.

If circumstances arise that cause us to change this inspection plan, we will contact you to discuss the change as soon as possible. Please contact me at 610-337-5129 with any questions you may have.

Sincerely,

Original Signed By:

James C. Linville, Director
Millstone Inspection Directorate

Docket Nos. 50-336; 50-423
License No. DPR-65; NPR-49

Enclosures:
1. Plant Issues Matrix
2. Inspection Plan

Attachment 7

Open Item Assessment
Millstone Unit 2

The following is a list of the open items that will remain after NRC Inspection Report 50-336/2000-01 is issued (inspection period 01/04/2000 to 02/14/2000).

LER 50-336/97-001-01	Inadequate Fire Seal Material Installed Between some Appendix R Fire Areas
LER 50-336/99-002-00	Violation of Technical Specification 4.3.3.9, Verification of Steam Generator Blowdown Throttle Valve Position
LER 50-336/99-003-00	Inadequate Net Positive Suction Head for Containment Spray Pumps
LER 50-336/99-004-00	Violation of Technical Specification 3.7.6.1., Positive Reactivity Addition to Reactor Coolant System from the Refueling Water Storage Tank
LER 50-336/99-005-00	Insufficient Verification of Technical Specification Surveillance 4.8.2.3.2., 125 Volt Class 1E Battery Bank Load Test
LER 50-336/99-006-00	Failure to Satisfy Reactor Coolant Pump Underspeed Sensing Circuit Response Time Technical Specifications Surveillance Requirement 4.3.1.1.3
LER 50-336/99-007-00	Failure to Monitor Steam Generator Primary and Secondary Coolant Temperatures in Accordance with Technical Specifications Surveillance Requirements
LER 50-336/99-008-00	Auxiliary Feedwater Regulating Valve Failed Surveillance Test, Entry into Technical Specification 3.0.3
LER 50-336/99-010-00	Failure to Perform ASME Section XI Inservice Testing on Pressurizer Relief Line Flow Control Sample Valve Follow-up
LER 50-336/99-012-00	Unrecoverable CEA Misalignment, Entry into Technical Specification 3.0.3
LER 50-336/99-013-00	Auxiliary Feedwater Pump Room High Energy Line Break Door Left Unsecured
URI 50-336/99-005-13	Unit 2 Post Accident Sampling System

The LERs which are not closed in the current resident inspection period (NRC Inspection Report 50-336/2000-06; 02/15/2000 to 04/01/2000) will remain open in the new inspection program.

URI 50-336/99-005-13 was inspected the week of February 14, 2000, and will be closed.

From NRC web site

Reports from U.S. Nuclear Power Plants During the Y2K Transition

This report from the Y2K Early Warning System (YEWS) contains descriptions of minor problems experienced by U.S. nuclear plants during the Y2K rollover from December 31 to January 1. The YEWS was intended to provide early notification to licensees, especially those in time zones further west, of potential Y2K problems at other plants. Event descriptions were prepared by NRC staff who were onsite at the time of the event. The descriptions reflect the information provided by licensees shortly after the event which was entered into YEWS at that time. None of these events affected the continued safe operation of the plants. A description of follow-up actions has been added for completeness.

It should be noted that the reported events represent all the events involving U. S. nuclear plants that were entered into YEWS. Minor problems may have occurred at other nuclear power plants which were not reported by licensees or entered into YEWS due to their low significance or similarity to previously reported problems.

Plant Name-Time	**Arkansas Nuclear 1 and 2** 01/01/2000@00:30
Description of Event:	After the transition to the year 2000 (Y2K), an operator and computer support technician attempted to program an electronic dosimeter in preparation to enter the radiologically controlled area (RCA) which is common to both units. The electronic dosimeter was unable to be programmed using the normal method at two computer programming stations. At that time, computer personnel determined that the software patch had not been uploaded to the computers. The patch was then uploaded to all stations successfully. Personnel would have been capable of programming the electronic dosimeter manually and entering the RCA.
Follow-up	This was considered to be a Y2K-related event. Because the software was repaired and the systems restored during the Year 2000 transition period, no follow-up action was considered necessary.

Plant Name-Time	**Indian Point 3** 01/01/2000@00:00
Description of Event:	At the Y2K transition there were two computer-related anomalies. Meteorological data, displayed digitally at a Control Room back panel, appears to have failed at the rollover. Wind speed, direction and stability were included in the display. Stability froze for about 30 minutes and then went blank. Wind speed and direction were displaying the same value and were considered frozen. The time stamp indicated as 2445 instead of 0045 and temporarily froze. Troubleshooting was still in progress at 0200 EST hours. Backup meteorological tower data was available and agreed with information at Indian Point Unit 2. Meteorological tower data is provided to Indian Point Unit 3 from the 10-meter elevation. Also, a control room digital display of the main generator stator temperature and an associated data logger correctly operated at 0000 EST, but failed to display the temperature data at 0100 EST. A strip recorder for the same data was operating correctly and was available to the operating staff for information purposes. The temperature data was not required by their license. The licensee rebooted the computer and the 0200 data printed automatically. Accordingly, the licensee considers the display returned to normal service as of 0200 EST. These occurrences had no operational impact or safety significance.
Follow-up	This was considered to be a Y2K-related event. Because the software was repaired and the systems restored during the Year 2000 transition period, no follow-up action was considered necessary.

A/D

Plant Name-Time	**Millstone 2** 12/31/1999@19:00
Description of Event:	An averaging program subroutine in the process computer which interfaces with programs using GMT gave erroneous results after 7:00pm EST (0000 GMT). Apparently only 2 averaged values were affected -- time average wind speed at the 142-foot elevation and time averaged readings from the in-containment gaseous and particulate radiation monitors. The operation of the plant was not affected, and there was no impact on safety. The instantaneous readings were not affected, and the averaging programs were reset successfully. The anomaly appears to be related to the Leap Year Calculation Model used in the subroutine. The licensee is still evaluating this anomaly
Follow-up	Millstone reports that this was not a Y2K problem but a leap year problem. This problem occurs every new year's eve (before a leap year) between 7:00 p.m. and midnight. A condition report was generated and the subroutine instructions were modified by information technology specialists so that the software will perform correctly in the future. Because this problem was entered into the licensee's corrective action program, no direct follow-up will be conducted on this item, other than in routine inspections of the licensee's corrective action program.

Plant Name-Time	**Monticello** 01/01/2000@00:30
Description of Event:	At the GMT Y2K transition there was a computer-related anomaly. The Met Tower computer (MIDAS) interface with the plant process computer (PPC) failed. The PPC would not accept data from the MIDAS computer. The MIDAS computer and associated control room chart recorders and instrumentation remained operational. Emergency preparedness meteorological data was unaffected. The PPC was also unaffected by the interface failure.
Follow-up	The MIDAS (met tower) computer was rebooted early on 1/1/00 which corrected the problem. Subsequent investigations revealed that the application problem was not caused by a Y2K related problem, but rather a known software inconsistency. The problem occurs when the met tower is writing a file for the process computer to read and the process computer attempts to read the file at the same time. The attempt to read simultaneously while writing happens infrequently. The result is a "file in use" error message sent to the process computer. After 6 attempts (at computer speed) the process computer writes a log message that an interface failure occurred. The computer log indicated that time and date were correct and the problem occurred due to a record lock (file in use) condition. This was a known problem, and because the met tower to process computer interface is not required and used as "information only," an immediate fix had not been planned. The licensee is investigating several strategies to correct the deficiency. The error on the Y2K roll-over was determined Monday afternoon to be a purely coincidental failure of this type.

Plant Name-Time	**Nine Mile Point 1** 01/01/2000@00:00
Description of Event:	A problem with the transmission of data from the meteorological (MET) monitoring system to the MET database occurred at the Y2K transition. This failure affected two systems due to their dependence on the MET data. The failure affected the emergency response data system (ERDS), an NRC system maintained by the licensee that provides plant parameter data, and the

	emergency dose assessment monitoring system (EDAMS). These systems will be capable of performing their functions by entering data manually in the case of EDAMS, or through verbal update to the NRC in the case of ERDS. The meteorological monitoring system is still providing accurate and complete weather data to the control rooms. The operation of the plant was not affected and there was no impact on safety. Computer technicians are looking into the problem. This problem also affected transmission of MET data to the adjacent FitzPatrick facility. However, the necessary data is still available and being manually entered into FitzPatrick computer systems.
Follow-up	The licensee stated that the meteorological problem was not Y2K related. It related to the long-term storage of data (>14 days). The licensee states that a software module failed and that this type of failure is not unusual. The system was rebooted successfully. There was no need for a contingency action since only long term data was affected and short term data was still available.
Plant Name-Time	**Palo Verde 1, 2, and 3** 12/31/1999@17:00
Description of Event	The satellite signal to the Kinemetrics 468DC Receiver which feeds the True Time IRIG-B clocks in each unit's emergency response facility data acquisition display system (ERFDADS) (non-safety related SPDS) system became invalid. All three units' ERFDADS determined that the day (Julian) is invalid, and all three computer systems have defaulted to their own internal system times. This situation is true for the new Digital Feedwater (DFW) System in Unit 1 as well. This has had no impact on proper functioning of these systems. At the rollover to 00:00 1 January 2000, the IRIG-B clocks re-synchronized to the satellite receiver signal. All computer systems utilizing this signal for time synchronization are now synched to the satellite clock.
Follow-up	A satellite signal for time synchronization is sent to a receiver on Unit 1 which then transmits the time signal to ERFDADS for all three units and to digital feedwater on Unit 1. This signal is transmitted once per hour. At midnight GMT the satellite time shows the year 2000 while the three ERFDADS clocks and the DFW clock show 1999. With the year difference the clocks will not synchronize with the satellite time. However, synchronization will occur at Midnight (Palo Verde time) as the clocks then will be in the same year as the satellite time. Apparently this is not unique to Y2K but happens every new year's eve. The problem lies with the receiver on Unit 1. The licensee has not noticed this in previous years and does not consider this to be a concern that needs correcting as the clocks will synchronize within the seven hours and no significant time difference (2 seconds) is seen during this short period.
Plant Name-Time	**Pilgrim 1** 01/01/2000@00:00
Description of Event:	When performing the 3D Monicore computer program trend plots, the licensee successfully completed the hourly and daily trend plots. However, when running the monthly trend plot, the 3D Monicore color graphics interface stopped displaying data but was restored within a few minutes. The licensee was able to ascertain core power and thermal limits were met at all times. The licensee has determined that system functionality is not affected. It is believed this is a generic issue (other BWR plants had related issues). Plants will work with the General Electric Boiling Water Reactor Owners Group (BWROG) to resolve.
Follow-up	This was considered to be a Y2K-related event. There has not been a final determination made whether or not this is a generic concern. However, it appears to have only affected the plant specific graphic interface. General Electric has notified the other BWRs with similar 3D Monicore programs and the issue and its final resolution is still under review. NRC staff will continue

	its interaction with General Electric and the BWR Owner's Group regarding this issue.