July 5, 2005

Mr. David A. Christian, Sr. Vice President
and Chief Nuclear Officer
Dominion Resources
5000 Dominion Boulevard
Glen Allen, VA 23060-6711

SUBJECT: MILLSTONE POWER STATION UNIT 3 - NRC SPECIAL INSPECTION REPORT 05000423/2005012

Dear Mr. Christian:

On April 29, 2005, the U.S. Nuclear Regulatory Commission (NRC) completed a Special Inspection of the April 17, 2005, inadvertent safety injection actuation and reactor trip at Millstone Power Station, Unit 3. This reactor trip and safety injection actuation was complicated by the subsequent trip of the Unit 3 turbine-driven auxiliary feedwater pump, overfill of the pressurizer, prolonged operation of two main steam safety valves, and significant leakage from the high head injection system. The enclosed report documents the inspection findings which were discussed with Mr. J. Alan Price and other members of your staff on May 18, 2005.

The inspection examined activities conducted under your license as they relate to safety and compliance with Commission rules and regulations and with conditions of your license. The team reviewed selected procedures and records, observed activities, and interviewed personnel. In particular, the inspection team reviewed event evaluations (including technical analyses), root cause investigations, relevant performance history, and extent of condition to assess the significance and potential consequences of issues related to the April 17, 2005 reactor trip. The enclosed Special Inspection Team Charter (Attachment 1) provides additional details on the scope of the inspection.

The team concluded that the overall response of Dominion Nuclear Connecticut (DNC) to the inadvertent safety injection actuation and reactor trip was adequate, in that the plant was taken to a safe shutdown condition. Nonetheless, several issues related to equipment reliability and human performance were identified. The team also noted that existing DNC processes for post-trip event review did not provide clear guidance on the scope and breadth of review necessary to assess complex plant events. The enclosed chronology (Attachment 2) provides additional details on the sequence of events and event complications.

This report documents six findings of very low safety significance (Green). Five of these issues were determined to involve violations of NRC requirements. However, because of their very low safety significance and because they were entered into your corrective action program, the NRC is treating these findings as non-cited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. If you contest any finding or violation in this report, you should provide a response, stating the basis for your denial, within 30 days of the date of this inspection report. Responses should be sent 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 Millstone.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosures, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

A. Randolph Blough, Director
Division of Reactor Safety

Docket No: 50-423
License No: NPF-49

Enclosure: NRC Inspection Report 05000423/2005012

cc w/encl:
J. A. Price, Site Vice President, Millstone Station
C. L. Funderburk, Director, Nuclear Licensing and Operations Support
D. W. Dodson, Supervisor, Station Licensing
L. M. Cuoco, Senior Counsel
C. Brinkman, Manager, Washington Nuclear Operations
J. Roy, Director of Operations, Massachusetts Municipal Wholesale Electric Company
First Selectmen, Town of Waterford
R. Rubinstein, Waterford Library
J. Markowicz, Co-Chair, NEAC
E. Woollacott, Co-Chair, NEAC
E. Wilds, Director, State of Connecticut SLO Designee
J. Buckingham, Department of Public Utility Control
G. Proios, Suffolk County Planning Dept.
R. Shadis, New England Coalition Staff
G. Winslow, Citizens Regulatory Commission (CRC)
S. Comley, We The People
D. Katz, Citizens Awareness Network (CAN)
R. Bassilakis, CAN
J. M. Block, Attorney, CAN

<u>Distribution w/encl</u> (VIA E-MAIL):
S. Collins, RA
S. Lee, RI OEDO
D. Roberts, NRR
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G. Wunder, NRR
S. Schneider, Senior Resident Inspector
E. Bartels, Resident OA
P. Krohn, RI
S. Barber, RI
T. Madden, OCA
Region I Docket Room (with concurrences)
ROPreports@nrc.gov
A. Blough, DRS
R. Crlenjak, DRS
M. Sykes, DRS
R. Conte, DRS

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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No:	50-423
License No:	NPF-49
Report No:	05000423/2005012
Licensee:	Dominion Nuclear Connecticut, Inc.
Facility:	Millstone Power Station, Unit 3
Location:	P. O. Box 128 Waterford, CT 06385
Dates:	April 20, 2005 - May 18, 2005
Inspectors:	G. S. Barber, Senior Project Engineer, Team Leader S. M. Schneider, Senior Resident Inspector J. G. Schoppy, Senior Reactor Inspector, Division of Reactor Safety (DRS) D. E. Jackson, Senior Project Engineer, Division of Reactor Projects (DRP) T. P. Sicola, Reactor Inspector, DRS R. L. Nimitz, Senior Health Physicist, DRS W. L. Schmidt, Senior Reactor Analyst, DRS P. A. Presby, Reactor Inspector, DRS N. S. Sieller, Reactor Engineer, DRP
Observer:	D. A. Galloway, Supervising Radiation Control Physicist, State of Connecticut, Department of Environmental Protection, Division of Radiation
Approved by:	Marvin D. Sykes, Chief Engineering Branch 1

SUMMARY OF FINDINGS

IR 05000423/2005012; 04/20/2005 - 05/18/2005; Millstone Power Station; Unit 3; Special Inspection for April 17, 2005 event; Event Follow up.

The NRC special inspection was conducted by a nine-person team comprised of resident inspectors, regional inspectors, and a regional senior reactor analyst. The team was accompanied by a radiation control physicist from the State of Connecticut, Department of Environmental Protection. The inspection team identified five Green non-cited violations (NCVs) and one Green finding (FIN). One additional issue, requiring further review, is being treated as an unresolved item (URI). The significance of most findings is indicated by the color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be "Green" or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. The inspectors identified a Green non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action” in that DNC’s did not promptly identify and correct a condition adverse to quality involving boric acid leaks in containment. The finding was more than minor because it affected the Initiating Events cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations; if left uncorrected it could become a more significant concern, such as excessive leakage or the loss of RCS integrity. In addition, this performance deficiency is related to the cross-cutting area of problem identification and resolution in two respects. First, after approximately six days and several containment entries, DNC had not identified the presence of 12 additional boric acid leaks. Second, although aware of the leak on a loop drain isolation valve, DNC did not re-evaluate or resolve the leakage impact on adjacent safety-related SSCs until questioned by the inspectors. This finding was determined to be Green (very low safety significance) based on IMC 0609, Appendix A, Phase 1 SDP worksheet for at-power situations. The leakage is characterized as a LOCA initiator, but assuming worst case degradation, the leakage would not have resulted in exceeding a TS limit for identified RCS leakage or have adversely impacted other mitigating systems.(Section 4.2)

Cornerstone: Mitigating Systems

- Green. The inspectors identified a Green non-cited violation in that DNC did not comply with 10 CFR 50, Appendix B, Criterion III, “Design Control,” regarding the suitability of a control room indicator in providing information needed by operators to ensure appropriate decision making while implementing emergency operating procedures. This violation is related to the misleading control room indication for Charging/Safety Injection (CHG/SI) flow indication which led operators to take improper actions in EOP E-0, “Reactor Trip or Safety Injection” because the flow indicator (3SIH-FI917), despite the existence of adequate injection flow to the core, indicated zero gallons per minute (GPM) flow. This self-revealing finding was of more than minor safety significance because it was associated with the design control attribute of the mitigating systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The finding was determined to be Green (very low safety significance) based upon IMC 0609, Appendix A, Phase 1 SDP worksheet for at-power situations. The inspectors determined that the finding represented a design deficiency that did not result in a loss function per Generic Letter (GL) 91-18, Revision 1. (Section 3.4)

- Green. The inspectors identified a Green finding because procedure MP-14-MMM, Revision 006-01, "Operations" was not adequately implemented. The team identified problems with crew diagnosis and communications during the event which led to an emergency plan declaration when actual conditions for that declaration did not exist. This NRC-identified finding is considered to be of more than minor safety significance because if left uncorrected, ineffective monitoring and diagnosis of plant conditions during significant plant events could lead to a more significant safety concern. In addition, this performance deficiency is related to the cross cutting area of human performance in that, during the actual event, the operating crew did not diagnose that the MSSVs were functioning as designed and crew briefings did not provide a complete perspective of known plant conditions. This finding was not suitable for the an NRC SDP evaluation, but was reviewed by NRC management in accordance with IMC 0612, Section 05.04c and determined to be of very low safety significance (Green). (Section 3.1)

- Green. The inspectors identified a Green non-cited violation of Technical Specification (TS) 6.8.1 because the operating crew did not take control of reactor coolant system (RCS) temperature in accordance with Step 21 of Emergency Operating Procedure (EOP), E-0, “Reactor Trip or Safety Injection”. Consequently, the main steam safety valves (MSSVs) automatically operated to control RCS temperature for approximately 30 minutes longer than was necessary. This NRC-identified finding is considered to be of more than minor significance because it adversely impacts the Mitigating Systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the unnecessary cycling of the MSSVs increased the chance that a previously cycled MSSV would not open or would fail to reseat following an additional opening. The finding was determined to be Green (very low safety significance) in accordance with IMC 0609, Appendix A, Phase 1 SDP worksheet for at-power situations. (Section 3.2)

- Green. The inspectors identified a Green non-cited violation of TS 6.8.1 regarding the deletion an 18-month control valve PM for TDAFW pump in August 2000 without performing a thorough change evaluation per CBM 105, Revision

004-03, Preventive Maintenance Program. This performance deficiency was a primary contributor to the TDAFW pump overspeed trip. This NRC-identified finding was of more than minor safety significance because it affected the Mitigating Systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, because the PM was not completed, the reliability of the TDAFW pump was adversely affected. In evaluating this finding, the Significance Determination Process (SDP) (Phase 1) screening identified that a SDP workbook (Phase 2) evaluation was needed because the TDAFW pump was potentially inoperable in excess of its TS Allowed Outage Time of three days. Since the Phase 2 evaluation exceeded a risk threshold, an NRC Region I Senior Reactor Analyst (SRA) conducted a Phase 3 evaluation to more accurately account for the exposure time and to appropriately credit operator actions to recover the TDAFW pump after it automatically tripped on April 17. The Phase 3 evaluation determined that this finding represented a change in core damage probability of low to mid E-7, which is of very low risk significance (Green). (Section 2.2)

- Green. The inspectors identified a Green non-cited violation for failure of the Millstone Unit 3 simulator to correctly model main steam safety valve operation as required by 10 CFR 55.46(c)(1), "Plant-Referenced Simulators." This NRC-identified finding is more than minor because it affected the human performance attribute of the mitigating systems cornerstone. This finding was evaluated using the Operator Requalification Human Performance SDP (IMC 0609 Appendix I) because it is a requalification training issue related to simulator fidelity. The SDP, Appendix I, Block 12, requires the inspector to determine if deviations between the plant and simulator could result in negative training or could have a negative impact on operator actions. "Negative Training" is defined, in a later version of the standard (ANSI 3.5-1993), as "training on a simulator whose configuration or performance leads the operator to incorrect response or understanding of the reference unit." During the event of April 17, 2005, operators were influenced by negative training on the simulator to erroneously believe that a safety valve in the plant was stuck open when it was actually still functioning as designed. (Section 3.3)

B. Licensee-Identified Violations

None.

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Report Details

1. Description of Events

1.2 Event Summary

On April 17, 2005, at 8:29 a.m., Millstone Unit 3 experienced a reactor trip from 100 percent power following an unexpected “A” train safety injection (SI) actuation signal and main steam line isolation (MSI). Control room operators entered emergency operating procedure (EOP) E-0, “Reactor Trip or Safety Injection,” Revision 22, and manually actuated the “B” train of safety injection within 30 seconds. The first-out annunciator panel indicated that the reactor trip was caused by a “Steam Line Pressure Low Isolation SI” signal sensed by the solid state protection system (SSPS). The Shift Manager (SM) arrived in the control room approximately five minutes after the reactor trip and assumed Director of Site Operations (DSO) duties.

As a result of the MSI signal, the main steam isolation valves (MSIVs) and two of the four main steam line atmospheric dump valves (ADVs) automatically closed. With the closure of the MSIVs, the main steam line safety valves (MSSVs) opened to relieve secondary plant pressure. Control room operators manually actuated the “B” MSI train in accordance with station procedures. Both motor driven auxiliary feed water (MDAFW) pumps started to maintain steam generator levels. The turbine-driven auxiliary feedwater (TDAFW) pump attempted to start but immediately tripped on overspeed. Operators were dispatched to investigate the cause of the trip. The TDAFW pump trip was subsequently reset and the TDAFW was restarted at 10:19 a.m.

At approximately 8:42 a.m., the SM noted that a “B” MSSV had remained opened for an extended period of time. In consultation with the Unit Supervisor (US) and Shift Technical Advisor (STA), the SM declared an ALERT based on a stuck open MSSV. The crew determined that the stuck open MSSV represented an unisolable steam line break outside containment.

At 8:45 a.m., due to the addition of the inventory from the SI, the pressurizer reached water solid conditions and the pressurizer PORVs cycled numerous times to relieve reactor coolant system (RCS) pressure and divert the additional RCS inventory to the pressurizer relief tank (PRT). No pressurizer safety valve actuations occurred and the PRT rupture diaphragm remained intact. The control room received reports of substantial leakage in the auxiliary building near the high head safety injection (HHSI) pumps. The leakage was coming from the packing of two valves in the HHSI system alternate minimum flow (AMF) line and was estimated to be approximately 60 gpm. Several hundred gallons spilled onto the auxiliary building floor.

At approximately 8:59 a.m., the operating crew transitioned from EOP E-0 to ES-1.1, “SI Termination”. The SI was reset and the crew terminated safety injection at 9:12 a.m and normal RCS letdown was re-established at 9:20 a.m. Millstone Unit 3 entered Mode 4 [Hot Shutdown] at approximately 7:03 p.m. and the ALERT was terminated shortly thereafter. NRC Region I had been in a “Monitoring Mode” during the event and returned to the Normal Mode at 11:45 p.m.

1.2 Radiological Assessment

a. Inspection Scope

The inspectors reviewed DNC's radiological assessment of the April 17, 2005 event. The review included an evaluation of public and occupational dose consequences and DNC's quantification of the total amount of radioactive materials released during and subsequent to the event. The purpose of the NRC review was to ensure that the releases were properly characterized, and that public doses were properly assessed as required by the Offsite Dose Calculation Manual (ODCM).

The following matters were reviewed against TS, the ODCM, and applicable DNC procedures:

- estimated quantity of radioactive material released to and from the Unit 3 turbine and auxiliary building and methods of calculation;
- radionuclide profile of fluids within the reactor coolant system;
- collection of effluent samples, as appropriate;
- calculations of maximum projected offsite doses and conformance with applicable ODCM requirements;
- calculations of estimated instantaneous release rates relative to applicable ODCM limits;
- implementation of supplemental sampling specified by the ODCM, as applicable;
- surveillance testing and operability of applicable effluent radiation monitoring equipment and radiological effluent filtration systems;
- conformance with radiological emergency action levels (EALs); and
- occupational doses to plant personnel during and following the event.

b. Findings and Observations

No findings of significance were identified.

DNC performed public dose projections by using actual in-plant measurements and worst case assumptions to calculate the estimates of the effluent releases. The dose projections used real-time meteorology; assumed ground level releases; and current ODCM methodology. The projections used two separate sources of effluent releases from Millstone Unit 3. The first was associated with off-gassing from a quantity of liquid released to the Unit 3 Auxiliary Building as a result of packing failure from two valves within the high head safety injection system (See Section 2.3). From this source, small quantities of radioactivity were released via operable Unit 3 charcoal and high efficiency particulate air (HEPA) filtered flow paths. The second source of effluent releases was associated with the release of steam from the various main steam safety relief valves which cycled during plant cooldown.

DNC calculated that a total of approximately 1.12 Curies of radioactivity was released from Unit 3 as a result of the event. As discussed, the calculated releases were from two sources. The main steam line safety valves released 0.014 Curies of tritium (H-3) from the secondary side of the steam generators during the cool down and pressure relief phase. This estimate of tritium activity was conservative and assumed that all available radioactivity was released from the secondary side of the steam generators and was based on samples collected prior to, during, and following the release. No other radionuclides were detected. From the second release point (Auxiliary Building), DNC calculated that approximately 0.006 Curies of noble gas (i.e., Xe-135 at about 87% and Kr-85m at about 13%) and 1.1 Curies of tritium was released to the Unit 3 Auxiliary building via off-gassing and evaporation from the liquid. All contained noble gasses were assumed to have been released from the water and tritium was released via evaporation of a calculated portion of the water. Although other radionulides were present in the water, none of these were released due to high efficiency particulate filtration and charcoal adsorbers located in the release path. This was confirmed by sampling down stream of the filter/charcoal adsorbers. In addition, in-plant airborne radioactivity sampling during the event, did not detect any significant airborne radioactivity at the location of the liquid spill. The spill was collected in sumps for processing.

Neither release resulted in an effluent monitor alarm or indication of release of radioactive materials above normally expected background levels. Both, the installed effluent radiation monitoring systems and the normal sampling systems, including grab sampling, showed no indications of a significant release of radioactive materials. The licensee teams that were dispatched for onsite and offsite radiological sampling and monitoring did not identify any detectable airborne radioactivity attributable to the event. Due to the low level of radioactivity within the effluents, no additional sampling or analyses were prompted or required by the station's ODCM. Calculated release rates were well within applicable ODCM limits. Notwithstanding, supplemental sampling was conducted which did not identify any significant releases. Further, the monitoring and sampling did not identify any indications of primary to secondary steam generator tube leakage. The inspectors confirmed that neither the effluent releases nor the release of liquid within Unit 3 Auxiliary Building resulted in any radiological emergency action levels (EALs) being reached.

DNC calculated a maximum projected whole body/organ dose of 0.0004 millirem at the site boundary. This dose value was compared against the most restrictive ODCM dose limit and found to be approximately 0.003% of the most restrictive applicable annual federal limit (an ODCM organ dose limit of 15 millirem) and approximately 0.002% of the applicable site whole body dose limit (an ODCM whole body dose limit of 25 millirem). The release did not result in any significant air dose due to gamma or beta radiation. Maximum calculated air dose values were less than 0.0001% of applicable limits specified in the ODCM. Dominion was continuing to review these calculated curie and dose values for further refinement for inclusion in its 2005 Annual Effluent Release Report to the NRC. The inspectors independently reviewed and confirmed the release results and determined that there were no consequences to public health and safety.

The event did not result in any significant occupational radiation exposures. Three minor personnel contaminations, associated with personnel entry into the Unit 3 Auxiliary Building, occurred which did not result in any dose of record. DNC initiated prompt action to decontaminate affected floor locations associated with the fluid leakage. No significant individual or aggregate dose was received from this activity.

2. Equipment Performance Issues and Root Causes

2.1 Solid State Protection System Circuit Card Malfunction

a. Inspection Scope

The inspectors reviewed DNC's root cause determination for the inadvertent solid state protection system (SSPS) actuation to determine the adequacy of the evaluation and the appropriateness of the extent of condition review. Inspectors also independently assessed other potential causal factors for the event. Field walkdowns were performed and independent observations of the "tin whisker" using a 40X microscope were conducted. This "tin whisker" apparently grew from a diode on the SSPS logic card creating a bridge from the diode to a trace to cause the inadvertent SI.

Additionally, DNC instrumentation and controls (I&C) technicians were interviewed to evaluate how the whisker was determined to be the cause of the fault. Following the interviews, inspectors evaluated SSPS functional logic and electrical diagrams to determine whether system response was consistent with the signal that would have been triggered by the apparent short circuit from the "tin whisker." After evaluating the system drawings, inspectors interviewed senior I&C technicians with regard to the individual logic chips on the circuit boards to determine the likelihood that a tin whisker could provide the voltage and current conditions that would be necessary to cause an actual signal in the control logic. The inspectors also reviewed functional diagrams of the "A" safety train, as well as, Millstone 3 Updated Final Safety Analysis Report (UFSAR) to confirm that the appropriate automatic functions occurred in response to the signal provided by the SSPS. On May 18, the inspectors reviewed DNC's root cause determination to assess its adequacy. After this assessment, additional extent of condition reviews were assessed.

b. Findings and Observations

No findings of significance were identified.

The inspectors noted that the apparent cause evaluation performed by the Millstone 3 I&C technicians demonstrated a thorough and excellent questioning attitude. Their detailed investigation of the circuit card (SSPS digital logic cards) malfunction led to the discovery of the "tin whiskering" phenomena which was difficult to discern.

The inspectors noted that DNC's extent of condition (EOC) review of the SSPS digital logic cards appeared reasonable. An initial sample of 10 percent of the 102 cards was selected. When additional whiskering was evident, DNC expanded their sample size in various increments until eventually an inspection sample of 100 percent of the cards was conducted. Each card was examined under a 40X microscope from three different angles and any whiskering discovered was tracked by a circuit card's card serial number. A maximum projected growth rate was established as a basis for whether the card could be returned to service or had to be replaced prior to restart.

While the EOC review for the SSPS cards appeared reasonable, there were initially no plans to conduct EOC reviews for other systems that used digital logic cards since preliminary DNC evaluations indicated that similar circuit cards used in the rod control system and emergency diesel generator sequencer were not susceptible to tin whiskers. Dominion also noted that other digital system cards did not need inspections because they had been supplied with a conformal coating (a dip or spray on a circuit board designed to limit corrosion) originally thought to prevent the whiskering. After further review by the inspectors and discussions with station personnel, DNC concluded that additional inspections were necessary to verify that tin whiskering was not evident in other systems that used digital logic cards. No additional EOC concerns were identified.

2.2 Turbine-Driven Auxiliary Feedwater Pump Overspeed Trip

a. Inspection Scope

Following the reactor trip, the TDAFW pump tripped on overspeed after receiving an automatic start signal. The inspectors reviewed DNC's root cause evaluations associated with the TDAFW pump overspeed trip. The inspectors independently assessed the causal factors for the failure and the appropriateness of DNC's initial corrective actions. The inspectors also reviewed procedures, records (including surveillance and maintenance history), industry operating experience (OE), event data, and condition reports (CRs); conducted system walkdowns (including a post-maintenance independent TDAFW pump operational readiness verification using procedure SP 3622.3-001); observed portions of the control valve's post-trip corrective maintenance; and interviewed plant personnel, including station management.

b. Findings and Observations

Introduction. The inspectors identified a Green non-cited violation of TS 6.8.1 in that DNC deleted an 18-month control valve PM for the TDAFW pump in August 2000 without performing a thorough change evaluation per CBM 105, Revision 004-03, Preventive Maintenance Program. This performance deficiency was a primary contributor to the TDAFW pump overspeed trip.

Description. Following the unexpected safety injection actuation and reactor trip, a feedwater isolation occurred which caused lowering steam generator (SG) water levels. Based on the sequence of events recorder data and on personnel interviews, DNC determined that within one minute of the SG lo-lo level alarm, the TDAFW pump attempted to start but experienced an electrical overspeed trip and coasted to a stop. The MDAFW pumps had successfully started and continued to run. Following an initial field investigation, operators successfully restarted the TDAFW pump at 10:19 a.m. The pump operated satisfactorily until operators removed the pump from service in accordance with plant procedures at 1:41 p.m. on April 17.

Dominion's initial assessment of the event concluded that the TDAFW pump overspeed was due to sticking/binding of the TDAFW control (throttle) valve. Prior to pump start, the control valve had been full open, in accordance with the system design. On a normal automatic start signal, the TDAFW pump control valve should quickly throttle closed to control turbine speed by controlling the amount of steam supplied to the turbine. During the April 17, 2005 event, the control valve stem bound against the carbon packing, thereby slowing down the valve response. Excess steam was admitted to the turbine, which resulted in a turbine overspeed and trip. To prevent recurrence of the control valve binding, DNC replaced the control valve stem and carbon packing prior to plant restart.

On April 28, DNC initiated a more in-depth review of the TDAFW pump overspeed and trip, which consisted of a significance level 1 root cause evaluation. Through this evaluation, DNC determined that the primary contributor to the mechanical binding of the control valve stem was degraded valve packing. Specifically, the carbon spacers in the packing had experienced uneven wear and had become deformed or “out of round.” As a corrective action to prevent recurrence, DNC established a new PM (CBM 105 No. 2005-0218) to replace the control valve carbon spacers and steel washers every 18 months.

The inspectors determined that DNC had deleted a similar PM in 2000 as part of a PM optimization process (CBM 105 N0. 2000-1199). The PM had instructed maintenance technicians to disassemble the control valve and inspect the valve stem for pitting and corrosion every 18 months. During valve re-assembly, the PM specified replacement of the carbon spacers and stainless steel washers. When DNC replaced their control valve stem with a corrosion-resistant Inconel material in 1999, in response to industry OE on stem binding, DNC determined that the stem binding problem had been addressed and 18-month PM was deleted.

The inspectors noted that the new PM established in response to the April 17, 2005 TDAFW pump overspeed trip appeared to reinstate PM activities that were similar to activities in the PM that DNC deleted in 2000. Specifically, both PMs called for the replacement of the control valve carbon spacers and steel washers on an 18 month periodicity. The inspectors noted that continued routine performance of the deleted 18-month PM would likely have prevented the mechanical binding of the control valve that was experienced on April 17, 2005, and would have provided additional opportunities for DNC to identify the propensity of the control valve carbon spacers to degrade.

The inspectors noted that although the Inconel stem was designed to resist corrosion, the Millstone 3 Terry turbine vendor manual continued to caution that "these stems must be closely monitored and inspected for evidence of binding conditions." However, DNC deleted their 18-month stem inspection PM without establishing an alternate means of inspecting or monitoring the control valve internal condition. Furthermore, DNC justified the deletion of their 18-month PM solely on the fact that the Inconel stem material was less susceptible to pitting corrosion than the previous stem material. The inspectors also reviewed various industry OE from the late 1990's which suggested that Inconel stems were still susceptible to binding. In particular, Information Notice 98-24, “Stem Binding in Turbine Governor Valves in Reactor Core Isolation Cooling (RCIC) and Auxiliary Feedwater (AFW) Systems,” discussed control valve binding issues associated with Inconel stems and misaligned carbon spacers. The stem binding issue had not been totally resolved by the industry (or Millstone Unit 3) in August 2000 when DNC elected to delete their 18-month PM.

Analysis. The performance deficiency was that DNC did not thoroughly evaluate the potential consequences associated with discontinuing a PM on the safety-related TDAFW pump control valve in August 2000 and did not conduct an adequate assessment per CBM 105, Revision 004-03, Preventive Maintenance Program. Discontinuing the PM was a primary contributor to the valve binding that caused the TDAFW pump overspeed trip on April 17, 2005. This issue was reasonably within DNC's ability to identify and correct prior to April 2005.

This NRC-identified finding was of more than minor safety significance because it affected the Mitigating Systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, because the PM was not completed, the reliability of the TDAFW pump was adversely affected. The finding is associated with the cornerstone attributes of equipment performance and human performance. The inspectors evaluated the finding in accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations." Based on the last successful TDAFW pump test on February 8, 2005 and the failure on April 17, (a time period of approximately 68 days), the calculated fault exposure time (t/2) was 34 days. In evaluating this finding, the Significance Determination Process (SDP) (Phase 1) screening identified that a SDP workbook (Phase 2) evaluation was needed because the TDAFW pump was potentially inoperable in excess of its TS Allowed Outage Time (AOT) of three days. Since the Phase 2 evaluation exceeded a risk threshold, an NRC Region I Senior Reactor Analyst (SRA) conducted a Phase 3 evaluation to more accurately account for the exposure time and to appropriately credit operator actions to recover the TDAFW pump after it automatically tripped on April 17.

Using the site specific Millstone Standardized Plant Analysis Risk (SPAR) Model, Revision 3.11, the SRA made the following assumptions to evaluate this finding:

- The exposure time used for this assessment was 34 days (816 hours).
- The basic event for operator failure to recover the TDAFW pump (AFW-XHE-XL-TDPFR) was revised from 1.0 to 0.1
- The basic event for the TDAFW pump was revised from it's nominal value of 4.1E-3 to 1.0 (TRUE).
- No additional failures were assumed and routine test and maintenance values were used.

The SRA determined that this finding represented a change in core damage probability of low to mid E-7, or very low risk significance (Green). The most dominant Phase 3 core damage sequences involved a loss of either the "A" or "B" 125 VDC Bus with a coincident loss or unavailability of the "A" or "B" motor-driven auxiliary feed water pump, respectively, and the failure of the operators to recover the TDAFW pump. Consistent with IMC 0609, Appendix A and Appendix H, "Containment Integrity SDP," and based upon the finding contributing to a change in CDF of greater than or equal to 1.0E-7, the finding was evaluated to determine if there were any risk contributions due to external events or large early release frequency (LERF). Based upon a review of the Millstone Unit 3, Individual Plant Examination for Severe Accident Vulnerabilities, submitted

August 31, 1990, the SRA determined that the finding did not significantly impact any postulated internal fire scenarios. In addition, this finding and the postulated core damage sequences screened out as potential LERF contributors.

Enforcement. Technical Specification 6.8.1 requires that written procedures shall be established, implemented, and maintained in accordance with Reg Guide 1.33, Revision 2, dated February 1978. RG 1.33 specifies that procedures are required for the work on safety related equipment. CBM 105, Revision 004-03, Preventive Maintenance Program specifies the control of preventive maintenance and appropriate reviews necessary to revise and/or change PM procedures. Contrary to the above, DNC deleted an 18-month control valve PM for TDAFW pump in August 2000 without performing a thorough change evaluation per CBM 105, Revision 004-03, Preventive Maintenance Program. Because this failure to adequately implement the PM change procedure was of very low safety significance, and the condition was entered into the DNC's corrective action program (CR-05-03734), this issue is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000423/2005012-01, Failure to Implement Appropriate PMs on the TDAFW Pump Control Valve)**

2.3 High Head Safety Injection System Leakage

a. Inspection Scope

During this event, the "A" charging pump automatically started, as designed in its high head safety injection (HHSI) mode. On pump start, the system pressure spiked to approximately 2512 psig (normal RCS pressure is approximately 2235 psig). Control room operators manually actuated the "B" train of HHSI. After approximately 30 minutes, the control room received notification of excessive leakage from two valves (3CHS*V661 and 3CHS*MV8511B) in the alternate minimum flow (AMF) piping flow path. The leakage continued while operators progressed through the EOPs to establish stable plant conditions. Once conditions were established, the operators terminated the SI and returned the system to a normal charging configuration.

The inspectors reviewed the system design, the impact of the pressure transient on system piping and components, and reviewed DNC's event investigation activities. The inspectors also independently assessed the causal factors for the leakage and the appropriateness of DNC's initial corrective actions. The inspectors reviewed procedures, records, data, and CRs; conducted system walkdowns; observed several Station Operations Review Committee (SORC) meetings; and interviewed personnel, including station management.

b. Findings

The inspection team noted that DNC had initiated an investigation to determine the apparent cause of the excessive leakage from 3CHS*V661 and 3CHS*MV8511B during the SI on April 17, 2005 (CR-05-03735). The DNC investigation concluded that the apparent cause of the excessive leakage was a particular failure mode of the Argo composite packing that caused it to extrude from the valves. The DNC staff contacted the packing vendor and were informed that it was not unusual for this particular type of packing to “blow out” (extrude) in this manner if the packing load is not sufficient and the vendor also indicated that valves that are known to be weeping should be repaired expeditiously. The vendor also commented that the charging system pressure spike could have initiated the failure. The DNC staff also determined that workmanship “skill of the trade” during packing installation may have also been a contributor, based on a previous plant occurrence in 1998. Prior to plant restart, engineering conducted charging system walkdowns to verify adequate packing load for all valves with Argo composite packing.

In response to the packing leaks, Dominion conducted a review of operating experience (OE) and maintenance history for the charging system valves. As a result, other possible causes for the packing failures were considered including water hammer transients, a valve timing induced hydraulic transient (due to the system realignment following the SI), and AMF relief valve (RV) operation.

The inspectors questioned the scope, breadth, and depth of the initial DNC evaluation of this issue. The team questioned the priority that DNC placed on understanding overall HHSI system response. The initial indications were that DNC intended to replace the damaged packing from the two valves (V661 & 8511B) and to perform an evaluation of the condition under a Priority 2 Condition Report with a 30 day evaluation due date. Although DNC management was aware of this issue, as of April 22 the team was not aware of specific plans to address performance aspects that had the potential to impact system operability. In particular, the team raised questions about the procedure for fill and vent because NRC walkdowns of system piping revealed that neither the suction nor discharge high point vent valves used to satisfy Technical Specification (TS) 4.5.2.b.1 were located at the high points in these respective lines. In at least one instance, the discharge piping vent valve appeared to be approximately 20 feet below significant portions of the AMF piping. These issues were discussed with DNC management on April 22 and a Mode 4 hold was implemented until this issue could be satisfactorily resolved. The licensee initiated two corrective action program reviews (CR-05-03926 and CR-05-04472) to evaluate the adequacy of the fill and vent process.

While the questions regarding the fill and vent procedure were addressed, other questions remained regarding the scope and breadth of the DNC evaluation of system performance. Specifically, the inspectors questioned the likelihood of a future water hammer with the revised fill and vent procedures; the reasons for the higher than expected contamination levels (mrad smearable) and the potential to result in post-accident accessibility issues, the potential existence of a containment bypass path during the event and other performance issues. Dominion initiated a significance level 1 root cause evaluation to evaluate the loss of Unit 3 charging system integrity (CR-05-03735). Pending completion of these investigations and NRC review of the root cause evaluation, this issue will be tracked as an unresolved item (URI). **(URI 05000423/2005012-02 DNC Integrated Assessment of Charging System Performance following the April 17, 2005 Inadvertent SI)**

2.4 Pressurizer Power-Operated Relief Valve Response

a. Inspection Scope

During the event, once the RCS reached solid water conditions, both pressurizer power-operated relief valves (PORVs) cycled approximately 41 to 43 times to limit the RCS pressure increases. Following the event, DNC noted that both PORVS exhibited minor seat leakage. Dominion replaced the “B” PORV with a ready spare and rebuilt the “A” PORV (new valve plug and seat). A post-event DNC engineering evaluation determined that none of the three pressurizer code safety valves had opened during the event.

The inspectors evaluated DNC’s post-event assessment and the adequacy of their initial corrective actions. The inspectors reviewed the design of the pressurizer system and the impact of the pressure transient on the pressurizer systems, structures and components (SSCs). The inspectors noted that the Millstone 3 FSAR states that both the PORVs and the PORV block valves are qualified for operation during subcooled water conditions (pressurizer water solid with no steam bubble). The inspectors reviewed the vendor manual, event data, and condition reports; conducted system walkdowns; observed portions of the “A” PORVs post-trip leakage testing and reinstallation activities; and interviewed personnel, including station management.

b. Findings

No findings of significance were identified.

2.5 Main Steam Safety Valve Response

a. Inspection Scope

Following the inadvertent SI and MSI signal, several MSSVs, atmospheric dump valves (ADVs), and ADV bypass valves actuated/operated during the event to control secondary side pressure. Post-event DNC engineering evaluations determined that “B” and “C” MSSVs opened at or near their design open pressure (1185 psig) and subsequently reseated following their design blowdown (approximately 6 -7 percent). Based on post-event main steam valve room walkdowns and the extended operation of the “B” MSSV, DNC decided to replace the MSSV with a ready spare.

The inspectors evaluated DNC’s post-event assessment and the adequacy of their initial corrective actions. The inspectors reviewed the design of the main steam pressure relief system and the impact of the pressure transient on the main steam SSCs. The inspectors reviewed the vendor manual, records (including recent RV open test results), event data, and CRs; conducted a system walkdown (including a post-maintenance inspection of the new “B” MSSV); observed several SORC meetings; and interviewed personnel, including station management.

b. Findings

No findings of significance were identified.

3. Human Performance and Procedural Issues

3.1 Event Diagnosis and Crew Dynamics

a. Inspection Scope

The team reviewed the event time lines, logs and instrument parameters recorded during the event to evaluate overall operator performance. Additionally, the inspectors conducted interviews with the on-duty control room operating crew and other station personnel to assess the overall performance of the operating crew based on the guidance in DNC Procedure MP-14-MMM, Rev. 006-01, "Operations," Section 2.0 "Responsibilities."

b. Findings

Introduction. The inspectors identified a Green finding because procedure MP-14-MMM, Revision 006-01, "Operations" was not adequately implemented. The team identified problems with crew diagnosis and communications during the event which led to an emergency plan declaration when actual conditions for that declaration did not exist.

Description. Following the SI and reactor trip, the operating crew diagnosed a stuck open MSSV on the “B” steam generator. In accordance with this diagnosis of plant conditions, the Shift Manager declared an ALERT based on an "Unisolable Steam Line Break Outside of Containment.” During a subsequent review, DNC determined that the MSSVs were in fact functioning as designed to relieve post reactor trip decay heat with a main steam line isolation signal present. The MSSVs closed once the operators took positive control of decay heat removal by remotely opening the atmospheric dump bypass valves.

At the time of the trip, the control room was staffed by a Unit Supervisor (US), a Reactor Operator (RO), a Balance of Plant Operator and a Shift Technical Advisor (STA). The Shift Manager (SM) was in a separate building attending a meeting. In response to the trip conditions, the crew entered the appropriate emergency operating procedure (EOP) and initiated a full SI actuation as required. In addition, at a later point in time, a full MSI was initiated. RCS pressure and temperature initially increased, due the closing of the main steam isolation valves (MSIVs) and the decay heat being generated. The “B” MSSV opened to remove decay heat and remained open for an extended period of time, maintaining “B” SG pressure between 1185 psig and 1105 psig.

The SM was made aware of the trip and proceeded to the control room (CR). He arrived at the control room after approximately five minutes. For the next two minutes, he toured the CR and recognized that both trains of safety injection were in service, and that annunciators were in alarm for "Safety Injection" and "Main Steam Line Pressure Low SI.” For the next four minutes, the US briefed the SM on plant status, noting that initially only a single train of SI had initiated and the redundant train had been manually actuated to complete a full SI. The US also noted that the TDAFW pump had tripped after an automatic start, and the “B” MSSV indicated open. The Shift Manager dispatched a plant equipment operator to obtain visual confirmation that the MSSV was open.

The Shift Manager reviewed the emergency action level (EAL) tables and the associated basis documents. Thirteen minutes into the event, based on his diagnosis of plant conditions and his solicitation of crew input, the Shift Manager concluded the “B” MSSV was stuck open, and that the conditions for an ALERT was met under classification "BA2-ALERT - Unisolable Steam Line Break Outside Containment". Subsequent reviews by DNC and the NRC confirmed that the actual plant conditions did not warrant such a classification.

Several days after the trip, the inspectors interviewed the SM, the US, the STA, and the two ROs. These interviews were conducted to gather information concerning the actions and the understanding of plant parameters during the response to the trip.

The Shift Manager stated that he believed that the cause of the reactor trip and SI was a failed open MSSV on the “B” SG. The SM recalled that the “B” MSSV was open, and that SG pressure in the “B” SG was at approximately 1110 psig and stable. He also stated that this pressure was about 15-20 psig lower than the other SG pressures. The SM stated that based on previous simulator training, he thought that the indicated conditions were consistent with a stuck open MSSV. Other crew members acknowledged that they were aware that plant parameters indicated that the low steam line pressure SI was not caused by valid plant parameters and they also noted that SG pressure indications did not drop below the setpoint that would cause a safety injection for low main steam line pressure.

The team’s review of control room logs and crew interviews revealed that RCS temperature and pressure and steam generator pressure trends indicated that the “B” MSSV was functioning as designed to remove decay heat and that the conditions noted for the ALERT declaration did not actually exist. The team noted that overall crew interactions and assessment of plant conditions including crew briefings did not provide a complete perspective of known plant conditions. Specifically, crew members did not adequately communicate unexpected plant system responses during the crew briefings.

Analysis. The team determined that operating crew diagnosis and communication during the event was a performance deficiency because operators are expected to properly evaluate and assess plant conditions and maintain awareness of plant status during all modes of operations, including emergency conditions. Traditional enforcement does not apply because, in this case, the finding did not result in an actual safety consequence, it did not impact the NRC's regulatory function, and was not the result of willful actions. The performance deficiency is considered to be of more than minor safety significance because if the condition is not corrected, ineffective monitoring and diagnosis of plant conditions during significant plant events could lead to a more significant safety concern. In addition, this performance deficiency is related to the cross cutting area of human performance in that, during the actual event, the operating crew did not diagnose that the MSSVs were functioning as designed and crew briefings did not provide a complete perspective of known plant conditions. This finding was not suitable for the an NRC SDP evaluation, but was reviewed by NRC management in accordance with IMC 0612, Section 05.04c and determined to be of very low safety significance (Green). This condition was entered into the DNC's corrective action program (CR-05-05566).

Enforcement. The inspectors identified no violation of NRC requirements associated with this finding. **(FIN 05000423/2005012-03, Improper Event Diagnosis led to E-plan Declaration)**

3.2 Emergency Operating Procedure Implementation

a. Inspection Scope

The inspectors reviewed the event time lines, logs and instrument parameters recorded during the event to evaluate overall operator performance. Additionally, the inspectors conducted interviews with the on-duty control room operating crew and other station personnel.

b. Findings

One NRC-identified finding and several team observations are included in this section. The observations constitute performance deficiencies of minor significance that are not subject to enforcement action in accordance with the NRC's Enforcement Policy.

Introduction. The inspectors identified a Green non-cited violation of Technical Specification (TS) 6.8.1 because the operating crew did not take direct control of reactor coolant system (RCS) temperature at the time directed by Step 21 of Emergency Operating Procedure (EOP), E-0, "Reactor Trip or Safety Injection." Consequently, main steam safety valves (MSSVs) continued to automatically open to limit RCS temperature rise for approximately 30 minutes longer than was necessary.

Description. On April 17, 2005, at 8:29 a.m., a reactor trip and safety injection occurred due to a failure within the solid state protection system (SSPS). Because the main steam isolation valves closed and the atmospheric dump valves also isolated due to the SSPS failure, the MSSVs opened automatically, as designed, to limit the pressure increase in the associated steam generator which, in turn, limited RCS temperature rise. The operating crew appropriately entered emergency operating procedure (EOP) E-0, "Reactor Trip or Safety Injection." At 8:45 a.m., the crew performed step 21 of E-0, which required the operating crew to check RCS temperature and take positive controlling actions if RCS temperature was not between 550 and 560E F. The crew recognized that RCS temperature at the time was 562E F. Although the Unit Supervisor ordered the appropriate positive controlling actions to relieve steam manually by using the Atmospheric Dump Bypass Valves to lower RCS temperature, the action was not taken by the crew. Because this action was not taken by the crew, the MSSVs continued to automatically open to limit RCS temperature at approximately 563E F. The inspectors later determined that the missed action was an oversight due to the level of activity in the control room soon after the reactor trip and SI. This human error prolonged operation of the MSSVs.

In addition, Step 21 of E-0 is considered a "Continuous Action Step." This requires the operating crew to take positive controlling actions at any future time in the EOP if RCS temperature is not between 550 and 560E F. At approximately 8:59 a.m., the crew implemented procedure ES-1.1, “Safety Injection Termination.” Step 15 of this procedure requires action to “Establish Main Steam Pressure Control Mode.” In this procedure, this step required the operators to place the atmospheric dump bypass valves in service to maintain SG pressure at 1100 psig. The operating crew correctly implemented this step and began controlling steam generator pressures which in turn controlled RCS temperature. This step was performed at 9:13 a.m. and the MSSVs closed soon after the crew took these positive controlling actions.

Because the operators did not take appropriate positive controlling actions per Step 21 of E-0 at 8:45 a.m., the MSSVs remained open for an additional 28 minutes, ultimately closing shortly after the operators implemented Step 15 of ES-1.1.

Analysis. The performance deficiency is that DNC did not correctly implement Emergency Operating Procedure E-0, “Reactor Trip or Safety Injection,” Step 21 as required by the plant’s technical specifications. The completion of Step 21 of E-0 actions was reasonably within DNC’s ability to foresee and correct and was preventable. Traditional enforcement does not apply because the event that occurred did not result in an actual safety consequence; it did not impact the NRC’s regulatory function; and was not the result of willful actions. This NRC-identified finding is considered to be of more than minor significance because it adversely impacts the Mitigating Systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage) and affected the human performance attribute of the same cornerstone. Specifically, the unnecessary cycling of the MSSVs increased the chance that a previously cycled MSSV would not open or would fail to reseat following an additional opening. The finding was determined to be Green (very low safety significance) in accordance with IMC 0609, Appendix A, Phase 1 SDP worksheet for at-power situations.

Enforcement. Technical Specification 6.8.1 requires that written procedures shall be established, implemented, and maintained. Specifically, a procedure providing mitigating actions for a Reactor Trip shall meet the above requirements since this procedure is listed in Reg Guide 1.33 Revision 2, dated February 1978. Contrary to this requirement, Step 21 of E-0 “Reactor Trip or Safety Injection” Revision 22 was not adequately implemented. Because this failure to implement this EOP step was of very low safety significance, and the condition was entered into the DNC’s corrective action program (CR-05-05568), this issue is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000423/2005012-04, EOP E-0 Step 21 not performed as required)**

c. Observations

EOP Documentation and Usage Issues

The team noted multiple examples of EOP documentation and usage issues for E-0, “Reactor Trip or Safety Injection,” and ES-1.1, “Safety Injection Termination” that were not in conformance with OP 3272, “EOP Users Guide,” Rev. 008-03, and DNAP-0509, “Dominion Nuclear Procedure Adherence and Usage,” Rev. 0. Each issue was evaluated for significance and determined to be minor based on the criteria specified in IMC 0612, Appendix B, Section 3. The specific issues include:

- The EOPs were marked up during the actual event with grease pencil, over a plastic sleeve. The actual procedure was not marked in a permanent fashion.

- Operators made several errors in marking the procedure steps as they were completed, including the following:

  - There were steps in the EOP that were completed as evidenced by actual actions in the plant, that were not marked in any way on the procedure as being complete.

  - E-0, Step 16 Response Not Obtained (RNO) actions were taken in an appropriate fashion, however, the procedure was marked as if the RNO was not implemented.

  - E-0, Step 24 is marked as if the RNO actions were taken, however, there is evidence that they were not taken.

  - ES-1.1, Step 20a is marked as if the RNO actions were taken, however, there is evidence that they were not taken.

  - ES-1.1, Step 28e is marked that the crew transitioned to OP 3208, however, this is not a transition point in the EOP, and the final six steps of the EOP show no annotation. These steps involved resetting SSPS signals that were not able to be reset at the time, and the procedure transition was desired. However, the EOP must be marked to show procedure progression.

3.3 Simulator Fidelity

a. Inspection Scope

The inspectors reviewed operator actions during the event and observed post-event simulator training in which operators were instructed on the noted differences between simulator and plant response. A demonstration of simulator response to a main steam line isolation signal was evaluated. Test records, deficiency reports, and condition reports related to the simulator were also reviewed.

b. Findings

Introduction. The inspectors identified a Green non-cited violation for failure of the Millstone Unit 3 simulator to correctly model main steam safety valve operation as required by 10 CFR 55.46(c)(1), “Plant-Referenced Simulators.”

Description. Inspector review of simulator response to a main steam line isolation signal from rated pressure and temperature conditions revealed that the Millstone Unit 3 simulator did not correctly reproduce the operating characteristics of the MSSVs. Specifically, NRC review determined that the MSSVs are simulated to open and close at or closely about their setpoint. In contrast, the MSSVs in the plant are designed to remain open after lifting until main steam pressure is lowered to a value significantly below their open setpoint. This design reseat feature is referred to as "blowdown."

During the event the "B" MSSV (3MSS*RV22B) in the plant was observed to close at approximately 6.75% (or 81 psi) below its open setpoint. Condition Report (CR) 05-03876, describes the design blowdown range of an MSSV in the plant to be between 3% and 9% of its open setpoint. Millstone Unit 3 operator training material (MSS039C, "Main Steam System", Revision 4, dated 05/12/2003), identified the design value for main steam safety valve blowdown (that pressure at which an opened main steam safety valve will reseat) as 60 psi below the open setpoint. A DNC evaluation conducted to address CR 05-03876 determined that the simulator was modeled to provide a blowdown value of 1.2% (15 psi). A test run on the simulator after the event demonstrated that the safety valve with the lowest setting opened and then reseated at its open setpoint. The simulated blowdown was observed at 0.083% (1 psi) below the design open setpoint of 1200 psia (1185 psig).

Table of Plant vs Simulator Values for Blowdown on 'B' SG Safety Valve 3MSS*RV22B

	Blowdown (%)	Blowdown (psi)
Plant Design Setting	3% to 9%	36 psi to 108 psi
Simulator Model Design Setting	1.2%	15 psi
Observed Plant Response	**6.75%**	**81 psi**
Observed Simulator Response	**0.083%**	**1 psi**

Millstone Unit 3 is committed to ANSI/ANS 3.5-1998, "Nuclear Power Plant Simulators for Use in Operator Training and Examination" and, accordingly, uses licensed operator training program scenarios as simulator scenario-based tests. Simulator Exercise Guide FS043S, "Rapid Downpower, Turbine Building Steam Leak," dated 01/22/2000, initiates a steam leak downstream of MSIVs. Using this scenario, simulator test conditions are established after operators initiate a manual main steam isolation that results in steam generator pressure on the simulator being maintained by safety valve operation at the valve opening setpoints. The scenario validation checklist identifies that the simulator guide has been evaluated for operating limits and/or anomalous response. DNC did not identify the problem with simulated safety valve response through performance of this test. However, observation of valve response, when compared either to the actual reference unit or to best-estimate data would have revealed this discrepancy between the simulator and the expected design response of the plant.

Analysis. The inspectors determined that the failure to ensure that the Millstone Unit 3 simulator correctly replicated expected plant response to transient conditions is a performance deficiency because DNC did not meet the requirements of 10 CFR 55.46(c)(1), "Plant-Referenced Simulators." This condition should have been foreseen because the operator training material identified MSSV blowdown as 60 psi while the actual blowdown observed during a simulator exercise was 1 psi. Understanding the behavior of the MSSV was also an enabling objective of the training material (MSS039C). Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements or DNC procedures. This finding is more than minor because it affected the human performance attribute of the mitigating systems cornerstone. This finding was evaluated using the Operator Requalification Human Performance SDP (IMC 0609 Appendix I) because it is a requalification training issue related to simulator fidelity. The SDP, Appendix I, Block 12, requires the inspector to determine if deviations between the plant and simulator could result in negative training or could have a negative impact on operator actions. "Negative Training" is defined, in a later version of the standard (ANSI 3.5-1993), as "training on a simulator whose configuration or performance leads the operator to incorrect response or understanding of the reference unit." During the event of April 17, 2005, operators were influenced by negative training on the simulator to erroneously believe that a safety valve in the plant was stuck open because it had not reclosed with pressure that was about 50 to 80 psi below its initial opening setpoint. Therefore, differences between the simulator and plant did have a negative impact on operator actions. The finding is of very low safety significance (Green) because the discrepancy did not have an adverse impact on operator actions such that safety related equipment was made inoperable during normal operations or in response to a plant transient.

Enforcement. Code of Federal Regulations, 10 CFR 55.46 (c)(1) requires, in part, that "the simulator must demonstrate expected plant response to transient conditions." Contrary to this requirement, the Unit 3 simulator safety valves did not demonstrate expected plant response to the April 17, 2005 spurious safety injection and main steam line isolation event. The failure to ensure that the simulator correctly replicates expected plant response to transient conditions is of very low safety significance and has been entered into the DNC corrective action program (CR-2005-03876). This violation is being treated as a non-cited violation, consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000423/2005012-05, Simulator response did not adequately model MSSV response)**

3.4 Misleading Control Room Indications

a. Inspection Scope

Inspectors reviewed the event time lines, logs and instrument parameters recorded during the event. Inspectors then reviewed EOPs to compare plant indications with expected plant responses for each step in the procedures. Finally, interviews were conducted with control room personnel on duty during the event to assess their responses to various indications and evaluate adequacy of actions taken and determine the cause of the erroneous indications.

b. Findings

Introduction. The inspectors identified a Green non-cited violation in that DNC did not meet 10 CFR 50, Appendix B, Criterion III, “Design Control,” regarding the suitability of a control room indicator in providing information needed by operators to ensure appropriate decision making while implementing emergency operating procedures. This violation is related to the misleading control room indication for Charging/Safety Injection (CHG/SI) flow indication which led operators to take improper actions in EOP E-0, “Reactor Trip or Safety Injection” because the flow indicator (3SIH-FI917), despite the existence of adequate injection flow to the core, indicated zero gallons per minute (GPM) flow.

Description. At 8:29 a.m., April 17, 2005, an inadvertent initiation of the “A” train of the solid state protection system (SSPS) occurred which generated a reactor trip, safety injection (SI) signal, and a single train main steam isolation (MSI) signal. In response to the MSI, all four main steam isolation valves (MSIVs) and two of four atmospheric dump valves (ADVs) automatically closed. Subsequently, operators manually initiated a full MSI signal which closed the remaining ADVs.

When stabilizing the plant, control room operators noted misleading indications on four different indication systems. The first, discussed below, was related to the CHG/SI flow indicator (3SIH-FI917) which indicated zero GPM flow when actual SI flow was being provided. The other three misleading indications relate to the ADV bypass valves (3MSS*74A, B, C, and D), the pressurizer PORVs (2335 psig setpoint), and the pressurizer code safety valves (2485 psig setpoint), which are discussed in the Observations section below.

The CHG/SI flow indicator, 3SIH-FI917, displays flow from zero to 1000 gallons per minute. Normally, a differential pressure flow transmitter output signal is conditioned through electronic square root extraction circuitry to provide a signal that is directly proportional to flow. However, in the case of 3SIH-FI917, the measured differential pressure signal is sent directly to the indicator. The indicator face is scaled to relate the differential pressure signal strength to flow, resulting in less precision at the bottom of the scale. The first scale marking above zero is at 200 gpm.

Operators reported that during the event, indicator 3SIH-FI917 never displayed above zero GPM. Post-event calculations confirmed that average charging SI flow rate was actually approximately 240 GPM. On the simulator, operators were able to identify flow of approximately 200 gpm on the flow indicator. Condition report CR-05-04493 was written to address this issue of inadequate flow indication as a design deficiency. A simulator deficiency report, DR-2005-3-0027, was generated to address the performance of 3SIH-FI917 during the inadvertent SI.

The erroneous no-flow indication provided by 3SIH-FI917 caused operators to take improper actions to assess a faulty system line-up and enter RNO actions in E-0, “Reactor Trip or Safety Injection”. DNC attributed the erroneous indication to the readability of the indicator under low flow conditions. The difficulty in reading this instrument had been previously highlighted in simulator training.

Analysis. The inspectors concluded that a performance deficiency existed because the CHG/SI flow meter design is such that a no-flow condition might be indicated when flow is present, influencing operators to take EOP actions which are not warranted. This condition should reasonably have been foreseen because operators are trained in the simulator on the difficulty of reading 3SIH-FI917 under low flow conditions. This self-revealing finding was of more than minor safety significance because it was associated with the design control attribute of the mitigating systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, with the reactor coolant system still at or above normal operating pressure, the poorly designed gauge led the operators to believe that the charging system was not performing its safety function. This complicated the event response by causing the operators to take unnecessary actions to verify that the charging system was functioning properly. The finding was determined to be Green (very low safety significance) based upon IMC 0609, Appendix A, Phase 1 SDP worksheet for at-power situations. The inspectors determined that the finding represented a design deficiency that did not result in a loss function per GL 91-18, Revision 1.

Enforcement. 10 CFR 50, Appendix B, Criterion III, “Design Control” states, in part, that “measures shall be established to assure that applicable regulatory requirements and the design basis...as specified in the license application, for those structures, systems, and components to which this appendix applies are correctly translated into specifications drawings, procedures, and instructions” and ”measures shall also be established for the selection and review for suitability of application of materials, parts, equipment, and processes that are essential to the safety-related functions of the structures, systems and components.” Millstone 3 Final Safety Analysis Report (FSAR) Section 1.8 indicates compliance with Regulatory Guide (RG) 1.97, Revision 2, and references FSAR Section 7.5, which includes, in part, a table listing variables identified to meet the intent of RG 1.97. This table includes flow in the high pressure injection system. RG 1.97 also specifies, in part, that “indications of plant variables that provide information on operation of plant safety systems and other systems important to plant safety are required by the control room operating personnel during an accident to (1) furnish data regarding the operation of plant systems in order that the operator can make appropriate decisions as to their use and ... allow for the early indication of the need to initiate action necessary to protect the public...” Additionally, it states that “It is essential that instrument ranges be selected so that the instrument will always be on scale.”

Contrary to the above, on April 17, 2005, the CHG/SI flow indicator (3SIH-FI917) provided misleading information to plant operators because it indicated zero GPM flow rate when actual injection flow was being provided to the core. This erroneous indication caused the operators to enter RNO actions in EOP E-0. Entering this procedure unnecessarily delayed operators in accomplishing additional EOP actions. However, because the violation was of very low safety significance and DNC entered the deficiency into their corrective action program under CR-05-4493, this finding is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000423/2005012-06, Misleading Control Room Indications)**

c. Observations

Other Discrepancies Between Simulator and Plant Response

In addition to the finding above, the inspectors noted several other discrepancies when comparing plant-referenced simulator response to actual plant response. For each of the items listed below, inspectors concluded that it was not reasonably within DNC's control to be able to foresee and correct these conditions. Therefore, the NRC does not consider these items as performance deficiencies. However, it is apparent that these discrepancies between the simulator and plant response should be addressed in order to ensure the fidelity of simulated plant component response. DNC created simulator deficiency reports to track resolution of each the following issues:

- During the event, as HHSI filled the pressurizer, rising RCS pressure caused the pressurizer PORVs to cycle between 41 and 43 times. Early cycling of the PORVs was shown by open and closed indicating light operation on the main control board. As the pressurizer approached solid conditions, the PORVs began to cycle more rapidly. During these later cycles, no open indications were received. CR-05-03889 attributes the lack of open indication to the rapid operation of the valve. On the simulator, position indication accurately reflects simulated valve position. In this way, the simulator does not reproduce the effect of rapid valve cycling on position indication. DNC generated simulator deficiency report DR-2005-3-0027 to address this issue.

- The pressurizer code safety valves utilize flow switches to provide position indication for the valves. These devices consist of a pair of resistance temperature detectors (RTDs), used to determine when a safety valve opens. One of the RTDs is heated and the other is not. Therefore, under normal conditions, a temperature difference exists between the heated and unheated RTDs. The RTD differential temperature is used to indicate that the safety valve is closed. When a code safety valve opens, the steam flow causes the RTD temperatures to equalize. Open indication is provided by the reduced differential temperature.

  During the plant event, as the pressurizer PORVs repeatedly opened and closed, the position lights for the code safety valves provided false indication that the safeties were also operating. CR-05-03869 was generated to address this problem. The licensee postulated that some steam/water mixture in the common piping downstream of the PORVs migrated back up the safety discharge lines, affecting their position indication RTDs. Corrective actions have been generated to evaluate alternate methods of position indication as a design fix.

  Unlike plant position indication behavior, the simulator safety valve position indication always accurately indicates simulated valve position. This appears to be deficient in two ways. First, the simulator does not model the time delay for closed indication inherent to the plant design. The plant RTDs must reestablish the differential temperature following valve closure before the valve will indicate closed. Secondly, the simulator does not model spurious safety valve open indication during extended PORV operation. Simulator deficiency report DR-2005-3-0027 was generated to address this issue.

- The MSSVs also utilize flow switches to provide position indication for the valves. As described for the pressurizer code safeties, these devices consist of a pair of RTDs used to determine when a safety valve opens. One of the RTDs is heated and the other is not. Under normal conditions, a temperature difference exists between the heated and unheated RTDs. The RTD differential temperature is used to indicate the safety valve is closed. Steam flow that occurs when a valve opens causes RTD temperatures to equalize. Open indication is provided by the reduced differential temperature.

  During the plant event, multiple MSSVs erratically indicated open upon the second manual operation of ADV bypass valves. A common drain system connects the discharge of the MSSVs with the ADV valves. DNC concluded that hot condensate from the atmospheric dump bypass valves affected the safety valve RTDs through degraded drain line excess flow check valves. CR-05-04277 was generated to address this problem. A corrective action has been assigned to address the condition which allows condensate drains to affect the safety valve position indication. Another corrective action has been assigned to adjust the RTD temperature settings to reduce the time delay for proper indication after a safety valve closes.
  The simulator design for the MSSVs provides indication directly related to actual valve position. This appears to be deficient in that it does not model the time delay for closed indication inherent to the plant design. The plant RTDs must reestablish the differential temperature following valve closure before the valve will indicate closed. Several minutes are expected to elapse after valve closure in the plant before closed indication is received. Changes to the plant settings may reduce this time. Furthermore, the simulator does not model spurious safety valve open indication during operation of the MOV74 valves. Simulator deficiency report DR-2005-3-0027, which addresses the simulator deficiencies identified through this event, should address this issue.

4. Licensee Response Activities

4.1 Event Review Activities

a. Inspection Scope

The inspectors reviewed the DNC's event review activities to evaluate the overall effectiveness of the event review team (ERT) activities in assessing event related issues. This review included observation of safety committee meetings, discussions and interviews with station personnel and management, review of station procedures and other key documents.

b. Findings

No findings of significance were identified. The number and nature of NRC observations outlined below would indicate an opportunity for DNC to improve the structure, scope, and level of detail in their event reviews.

c. Observations

On April 20, the inspectors observed the presentation of the ERT report (Memo OR-05-006 dated April 20, 2005) to the Station Operations Review Committee (SORC) and noted that the SORC members appeared to ask probing questions about the actual information contained in the report. At the conclusion of the meeting, SORC accepted the report with some minor comments. The inspectors had observed the discussion during the SORC meeting and reviewed the April 20 ERT report and had noted that neither the report nor the discussion addressed a number of relevant event related issues including the anomalous indications of the pressurizer PORVs and code safety valves when the pressurizer approached water solid conditions, and the erroneous open indications of the MSSVs when the ADV bypass valves were opened (Section 3.4). The inspectors also noted that the ERT report also stated, in part, that “Training and simulator modeling issues identified by the team are not restart issues.” The actual amount of MSSV blowdown modeled in the simulator as compared to plant response was considered a negative training issue (Section 3.3) and was a contributor to the inappropriate diagnosis of the event which led to an errant emergency plan classification (Section 3.1). DNC’s processes specified that the scope and timing of the training for the event would be determined by the Shift Manager. The inspectors determined that as of April 22, with plant restart projected for April 24, no specific training on the event was planned. Because of the anomalous indications that were evident, the need for additional training was discussed with DNC management on April 22, and subsequently, three sessions of simulator and classroom training were completed with all licensed operators on April 25, which was prior to plant restart.

The procedures used by the ERT to assess this event primarily focused on post trip data collection and did not provide clear guidance on the scope and breadth of the review necessary to adequately assess complex plant events. There was no specific procedure on the conduct of ERT activities. In reviewing the ERT’s activities, the inspectors noted that the:

- ERT reviewers did not conduct independent interviews of operations personnel involved with the event. A group interview was conducted. Conversely, the NRC conducted individual interviews and identified one of the three contributors to the Diagnosis and Crew Dynamics finding (Section 3.1);
- April 20 ERT Report called the Alert Declaration as conservative (Section 3.1);
- DNC containment walkdowns of potentially affected piping systems and equipment were not conducted until six days after event. (Section 4.2); and
- DNC did not have plans to perform an integrated review of the charging system performance (Section 4.2)

The team discussed these and other event-related issues with DNC and DNC initiated a total of five root and apparent cause investigations.

4.2 Post-Trip System Walkdowns

a. Inspection Scope

Based on the extensive system actuations and interactions that had occurred during the event, the inspectors conducted system walkdowns to identify potential transient-induced effects and to assess the associated structures, systems, and components

(SSCs) for restart readiness. On April 21, following DNC's Restart Readiness Review and initial restart SORC, the inspectors walked down the charging pumps, SI pumps, RHR pumps, auxiliary feedwater (AFW) pumps, and the main steam valve room (including the main steam isolation valves). On April 22, the inspectors walked down the EDGs, which ran unloaded during the early stages of the event for over an hour. Late on April 22 through the early morning of April 23, the inspectors walked down the Unit 3 containment including the pressurizer PORVs, safety valves, and pipe supports; reactor coolant pumps; SGs; PRT (including the rupture disks); and the containment sump.

b. Findings and Observations

One NRC-identified finding and two observations are documented in this section. The observations involve minor issues but were considered important because of the problem identification and resolution cross-cutting aspects. Although the observations should be addressed, they constitute performance deficiencies of minor significance that are not subject to enforcement action in accordance with Section VI.A of the NRC's Enforcement Policy.

Reactor Coolant System Leakage and Boric Acid Corrosion Control (BACC)

Introduction. The inspectors identified a Green non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," in that DNC did not promptly identify and correct a condition adverse to quality involving boric acid leaks in containment.

Description. During an NRC walkdown of containment on April 23rd, the inspectors identified 17 examples of boric acid residue accumulation on safety-related components. In one case, the leakage from an RCS Loop 2 drain isolation valve (V205) had deposited boric acid residues on nearby pipe supports, insulation, and the containment floor. These examples were provided to the licensee for evaluation. Subsequently DNC determined that only 5 of these boric acid leaks had been previously identified and evaluated within their BACC program. Several CRs were created to track corrective actions for each of the leaks.

The RCS Loop 2 drain valve leakage had been previously identified in September 2002 and Dominion had planned to correct the leakage during the Fall 2005 refueling outage (3R10). The inspectors noted that the leak from this valve had not been re-evaluated nor had the impact of significant boric acid residue accumulation on adjacent safety-related SSCs. A subsequent evaluation by DNC confirmed that a small body-to-bonnet leak (approximately 4 drops per minute) existed but there was minimal damage to the nut. Further review by DNC concluded that the valve would not be damaged by an additional six-months of exposure to leakage. However, the amount of leakage onto the pipe supports was determined to be of concern and DNC engineering isolated an upstream valve which successfully stopped the leakage. Dominion plans to repair the leaky RCS Loop 2 drain valve during the next refueling outage.

On April 23 and 24, DNC personnel made numerous containment entries to address the remaining 16 identified boric acid leaks in accordance with DNC's BACC program. These actions included BACC inspections, degradation evaluations, boric acid residue cleanup, and valve packing adjustments as necessary. DNC engineers did not identify any significant leakage or any boric acid corrosion on any of the associated SSCs.

Analysis. The performance deficiency was that DNC did not promptly identify, evaluate, and/or correct boric acid leaks in containment. DNC missed several opportunities to identify the issues between April 17 and April 23, during numerous containment entries made by DNC personnel in preparation for plant restart. These issues were reasonably within DNC's ability to foresee, identify and correct. The finding was more than minor because it affected the Initiating Events cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations; if left uncorrected it could become a more significant concern, such as excessive leakage or the loss of RCS integrity. In addition, this performance deficiency is related to the cross-cutting area of problem identification and resolution in two respects. First, for six days after the event and following several containment entries, DNC had not identified the presence of 12 additional boric acid leaks. Second, although aware of the leak on the loop drain valve, DNC did not re-evaluate or resolve the leakage impact on adjacent safety-related SSCs until questioned by the inspectors. This NRC-identified finding was determined to be Green (very low safety significance) based on IMC 0609, Appendix A, Phase 1 SDP worksheet for at-power situations. The leakage is characterized as a LOCA initiator, but assuming worst case degradation, the leakage would not have resulted in exceeding a TS limit for identified RCS leakage or have adversely impacted other mitigating systems.

Enforcement. 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," requires that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. Contrary to the above, prior to April 23, 2005, DNC did not promptly identify and correct a condition adverse to quality involving boric acid leaks in containment. Specifically, the inspectors identified 12 examples of boric acid residue accumulation on safety-related components that were not previously identified by DNC and evaluated within their BACC program. In addition, the inspectors identified an RCS loop drain isolation valve with significant boric acid residue accumulation that had been originally identified by DNC in September 2002 but had not been corrected nor recently re-evaluated for its potential to adversely impact the RCS pressure boundary. However, because the finding was of very low safety significance and has been entered into the DNC CAP (CRs 05-04113, 05-04124, 05-04127, 05-04129, 05-04130, 05-04132, 05-04133, 05-04135, 05-04136, 05-04138, 05-04139, 05-04141, and 05-04154), this violation is being treated as an NCV, consistent with section VI.A of the NRC Enforcement Policy. **(NCV 05000423/2005012-07, Less than adequate corrective actions for potential RCS pressure boundary degradation due to boric acid corrosion)**

Observations

Pressurizer Spray Line Snubber Issue

On April 23, the inspectors identified a degraded pressurizer spray line mechanical snubber (3-RCS-1-PSSP-0064) during a post-event containment walkdown. In particular, the clip was missing and the snubber alignment pin had backed more than half way out of the snubber hangar clamp assembly resulting in displacement of the snubber support and potentially impacted its ability to perform its safety function. Dominion documented the condition in CR-05-04113. On April 23, maintenance technicians fully inserted the pin into the hangar assembly, installed snap rings per their minor maintenance procedure, and declared the snubber operable.

Dominion noted that the snubber was last visually inspected on September 11, 2002 as part of a 100 percent snubber visual inspection. Dominion also determined that the snubber had been inoperable prior to the 4/13/05 repair based on the as-found evidence of pin disengagement. DNC engineering determined that the degraded pin condition, if not discovered and corrected, would have eventually led to full disengagement during thermal cycling, high frequency low amplitude vibration, or a dynamic event. On May 14, DNC initiated CR 05-05401 to further evaluate the apparent cause, extent of condition, and past operability of the associated spray line. Based on a piping analysis, DNC determined that the associated pressurizer spray line piping remained operable and capable of performing its safety function.

The inspectors noted that DNC did not conduct a timely, thorough walkdown of potentially impacted piping systems following a significant operational transient. Even absent this walkdown, DNC missed several opportunities to identify the issue prior to April 23, due to the numerous PORV-related maintenance activities in the immediate vicinity of the degraded snubber. This issue was reasonably within DNC’s ability to identify and correct prior to April 23, 2005. Although this issue was considered minor because subsequent evaluation concluded that the pressurizer spray line piping remained operable even with an inoperable snubber, DNC missed an opportunity to perform a timely walkdown of containment to assess post-event impacts.

<u>PORV Discharge Line Bent Strut</u>

During the containment walkdown on April 23, the inspectors identified a bent strut (PSR-817) on the PORV discharge piping and notified DNC of the discovery. Followup walkdowns by DNC personnel on April 24 identified several other degraded supports on the ASME Class 4 piping on the PORV discharge path to the PRT. In particular, hanger PSSH-814 showed some deformation, hanger PSSH-818 had a bent rod, and mechanical snubber 3RCS1PSSO0827 had the spherical bearing separated from the extension piece padeye. Dominion documented these issues in CR-05-04113, CR-05-04153, and CR-05-04186. Dominion determined that all of these supports are located on Class 4 piping, far enough from the Class 1/Class 4 ASME Code break that they would not adversely affect the Class 1 portion of the system. Dominion replaced the buckled strut and repaired the mechanical snubber prior to plant restart. Dominion planned to repair the degraded hangers in their next refueling outage. Subsequently, DNC decided to verify that the PORV supports operated as designed, especially considering the April 17 event was the first of its type since the design change to qualify the PORVs to pass water in the mid-1990's.

The inspectors noted that Millstone Unit 3 TS 4.7.10.D states “An inspection shall be performed of all snubbers attached to sections of systems that have experienced unexpected, damaging transients as determined from a review of operational data and a visual inspection of the systems within 6 months following such an event. In addition to satisfying the visual inspection acceptance criteria, freedom-of-motion of mechanical snubbers shall be verified using at least one of the following: (1) manually induced snubber movement; or (2) evaluation of in-place snubber piston setting; or (3) stroking the mechanical snubber through its full range of travel.” Following the April 17 event, DNC initiated CR-05-03728 for engineering to evaluate the applicability of this TS requirement to the April 17 plant transient. DNC’s investigation determined that a snubber inspection was not required based on their review of plant process computer data that showed “no abnormal RCS pressures associated with this plant trip.” The inspectors noted that DNC closed this investigation on April 21, prior to any DNC engineering containment walkdowns. Based on the NRC-identified containment walkdown issues, DNC re-evaluated their previous determination that “no snubber inspection was required” and initiated CR-05-04651 on May 2 to address this issue. Although this issue was considered minor because subsequent evaluation concluded that there was no impact on PORV discharge line operability, DNC missed an opportunity to perform a timely walkdown of containment to assess post event impacts.

5.0 Emergency Communications and Event Response Data System (ERDS) Activation

a. Inspection Scope

On April 17, 2005 following an unexpected SI and reactor trip, DNC declared an ALERT at 8:42 a.m. DNC was unable to activate the ERDS system within 1 hour of the declaration of an ALERT or higher emergency classification in accordance with 10 CFR 50.72 (a)(4) and station procedures because of an apparent software malfunction. The ERDS system was not activated until approximately 12:03 p.m., three hours and 21 minutes after the Alert declaration.

The inspectors conducted a review of the DNC’s response to the system malfunction and the resulting effects on NRC incidence response activities, including the establishment of emergency communication links and the subsequent activation of the ERDS. The review involved in-office evaluation of captured screen-shots from the NRC ERDS monitor and interviews of cognizant DNC Operations, Emergency Preparedness and Information Technology (IT) personnel.

b. Findings and Observations

No findings of significance were identified.

Following the ALERT declaration by DNC, the NRC established a continuous communication link with DNC to monitor plant conditions and onsite emergency response activities. The communication link is a primary means of assessing plant status. The NRC also requested that the Emergency Response Data System be activated to provide supplemental information on key plant parameters that may also be used to monitor plant conditions.

A review of NRC records and interviews of NRC personnel involved in the incident response center indicated that the ERDS system had not been activated within one hour of the ALERT declaration. Followup investigation revealed that plant operators had attempted to activate the system in accordance with Section 2.4 of MP-26-EPI-FAP07 “Notifications and Communications” but an unexpected software malfunction prevented system operation. Once the operator noticed that ERDS had failed to activate, the operator contacted Dominion’s Information Technology (IT) department for assistance. Upon arrival, the IT technician was able to correct the problem and activate the system at approximately 12:03 p.m., three hours and 21 minutes after the Alert declaration. Based on the circumstances associated with this event, this issue was not identified as a performance deficiency because the failure to meet the requirement for activation of ERDS was not reasonably within the licensee's ability to foresee and correct.

Throughout this period, the NRC maintained continuous communication with the licensee to monitor plant conditions via the communicator links. Onsite NRC inspectors were also available to observe plant activities and provide independent assessment of plant conditions. While ERDS is an effective tool in emergency, in this case, the team determined that the unforseen delay in activating the system did not prevent or inhibit the NRC's emergency response activities.

6.0 Preliminary Risk Significance of the Event

The Senior Reactor Analyst (SRA) performed an initiating event risk assessment of the April 17 automatic reactor trip and SI to determine that a special inspection team was the appropriate NRC inspection response to the event. The initiating event assessment was conducted using the Millstone 3 Standardized Plant Analysis Risk (SPAR) model, revision 3.11 and Systems Analysis Programs for Hands-on Integrated Reliability Evaluations (SAPHIRE) Version 7.0, revision 24. The risk assessment was based upon the following assumptions and known conditions at the time of and shortly following the automatic trip:

- The TDAFW pump started but failed to run. Plant operators were able to reset and successfully run the TDAFWP. The analyst did credit restart of the TDAFW pump in the risk assessment.
- The "A" and "C" charging pumps were removed from service due to related system valve packing leaks.
- The main steam isolation valves (MSIVs) went closed following the automatic trip, removing the capability of the power conversion system to remove decay heat.
- As a consequence of the MSIVs closing, the pressurizer went solid and lifted a power operated relief valve (PORV). The valve did properly reseat following the lift.

The conditional core damage probability (CCDP) for this event was approximately 3.4 E-6. The dominant accident sequences for this transient involved: failure of the PORV to reseat and subsequent failures of the residual heat removal and high pressure recirculation systems; and failure of the auxiliary feedwater system and subsequent failure of the operators to initiate feed and bleed of the primary. The low E-6 CCDP for this event represents low to moderate risk significance. Based upon equipment issues and operator response to this event, a special inspection team was initiated to review the event and related human performance.

7.0 LER Review

(Closed) LER 050000423/2005002, Inadvertent Reactor Trip and Safety Injection

On April 17, 2005, the Millstone Unit 3 reactor experienced an inadvertent reactor trip and safety injection (SI) actuation. The faulty SI signal was generated by the solid state protection system (SSPS) when a tin whisker, growing on an SSPS logic card, shorted the card output. The reactor trip and SI actuation was complicated by the subsequent trip of the turbine driven auxiliary feedwater pump, overfill of the pressurizer and relief of reactor coolant system inventory to the pressurizer relief tank, apparent prolonged opening of two main steam safety valves, and sizeable leaks in the charging system. The operations shift manager declared an Alert (Event No. 41607) in response to the “B” SG safety valve remaining open for an extended period of time.

This event was reviewed in detail by the special inspection team, and their findings and observations are discussed in the preceding sections of this report. This LER is closed.

8.0 Meetings

On April 29, 2005, the NRC Special Inspection Team met with Mr. David Christian, Mr. William Matthews, Mr. Alan Price, and other members of Millstone management to debrief them on the preliminary results of the Special Inspection to date.

On May 18, 2005, the NRC Special Inspection team presented the inspection results to Mr. Alan Price and other members of licensee management. The inspectors asked DNC whether any material examined during the inspection should be considered proprietary. No proprietary information was identified.

During the evening of May 18, 2005, the NRC Special Inspection Team also presented the inspection results to the Connecticut Nuclear Energy Advisory Council (NEAC). The public was given an opportunity to provide comments and to ask questions following the presentation.

April 20, 2005

MEMORANDUM TO:	Marvin D. Sykes, Manager Special Team Inspection	
	G. Scott Barber, Leader Special Team Inspection	
FROM:	Wayne D. Lanning, Director Division of Reactor Safety	**/RA/**
	A. Randolph Blough, Director Division of Reactor Projects	**/RA/**
SUBJECT:	SPECIAL TEAM INSPECTION CHARTER - MILLSTONE UNIT 3 NUCLEAR GENERATING STATION	

A special inspection has been established to inspect and assess an event that occurred on April 17, 2005, at the Millstone Unit 3 Nuclear Generating Station. At 8:29 a.m., Unit 3 experienced an automatic trip from full power. In addition to the Reactor trip, one of two safety injection (SI) and main steam isolation (MSI) subsystems actuated. Multiple main steam safety valves (MSSV) opened and at least one MSSV appeared to remain open. Failure of the MSSV to reclose resulted in the declaration of an Alert at 8:42 a.m.

Unexpected equipment responses during the event included the trip of a turbine-driven auxiliary feedwater pump on startup; overfill of the pressurizer as a result of the SI actuation; relief of reactor coolant system inventory to the pressurizer relief tank (PRT) through either a primary system safety valve (PSSV) or a pilot operated relief valve (PORV); indication of continued leakage past a pressurizer PORV; and charging system packing leakage resulting in local contamination in the auxiliary building. The special inspection will commence on or about April 20, 2005, and will include:

Manager:	Marvin D. Sykes, Chief, Performance Evaluation Branch
Leader:	G. Scott Barber, Senior Project Engineer
Full Time Members:	Thomas Sicola, Reactor Inspector Donald Jackson, Senior Project Engineer Joseph Schoppy, Senior Reactor Inspector
Part Time Members:	Wayne Schmidt, Senior Risk Analyst Ronald Nimitz, Senior Reactor Inspector Nicole Sieller, Reactor Inspector

This special team inspection was initiated in accordance with NRC Management Directive 8.3, “NRC Incident Investigation Program.”

The decision to perform this special team inspection was based on deterministic criteria in Management Directive 8.3 and the initial risk assessment. Specifically, the condition involved possible adverse generic implications, may have included unexpected system interactions, and involved questions or concerns pertaining to licensee operational performance. The initial risk assessment characterized the conditional core damage probability to be approximately 3 E-6, which is in the range for a special inspection.

The inspection will be performed in accordance with the guidance of NRC Inspection Procedure 93812, “Special Inspection,” and the inspection report will be issued within 45 days following the exit meeting for the inspection. If you have any questions regarding the objectives of the attached charter, please contact Wayne Lanning at 610-337-5126.

Attachment: Special Inspection Charter

Special Inspection Charter

Millstone Nuclear Generating Station

Unit 3 Reactor Trip and Safety Injection With Failure of Main Steam Safety Valve to Reseat

Preliminary information regarding the event: On April 17, 2005, at 8:29 a.m. Millstone Unit 3 experienced a reactor trip from full power. In addition to the reactor trip, one of two trains of the SI and MSI subsystems actuated. Control room operators manually initiated a full SI and MSI. There were also indications that multiple MSSVs opened with at least one MSSV that appeared to remain open. As a result, at 8:42 a.m., Dominion Nuclear Connecticut (DNC) declared an Alert due to the failure of at least one MSSV to reclose. The response of the MSSVs is under further review.

The SI and MSI signals were initially attributed to a sensed low steam line pressure on one of four steam generators. Auxiliary Feedwater (AFW) automatically actuated during the event. However, the turbine-driven AFW pump initially tripped and was successfully reset locally and restarted. Both motor-driven AFW pumps operated as expected to maintain steam generator levels. Due to the additional inventory added during the SI, the pressurizer filled and an overpressure condition caused pressurizer valves to open. Operators responded to these conditions, stabilized the plant in Hot Standby and began a cooldown. Subsequently, the plant entered hot shutdown at 7:03 p.m. and DNC terminated the Alert at 7:05 p.m

Objectives of the Special Inspection: The objectives of the special inspection are to evaluate the circumstances associated with the event described above. Specifically, the inspection should:

6. Develop or verify the accuracy of a licensee-developed detailed event chronology and sequence, including key transition and operator decision points.

7. Independently determine the apparent cause(s) that initiated the event including any relation to previous maintenance, equipment issues, or precursor events.

8. Understand the safety injection system response and determine, given the initiating event(s), whether actuation of only the Train - ‘A’ SI/MSI was appropriate.

9. Independently evaluate the equipment performance deficiencies and operator response that occurred during this event, including:

   A. operator control of the plant during the event including abnormal and emergency operating procedure usage, the bases for decisions made, and actions taken.

   B. operator ability to terminate the safety injection prior to the pressurizer going solid and evaluation of continued additions to the PRT.

   C. efforts to confirm that no primary-to-secondary leakage was occurring and the basis for the decision to utilize the ‘D’ steam generator as one of the means for reactor decay heat removal prior to obtaining confirmatory chemistry samples.

D. a review of the radioactive effluent stream data for the time period associated with the event.

E. trip of the turbine-driven auxiliary feedwater pump.

F. packing leakage from charging system valves that resulted in significant local contamination levels in the auxiliary building.

G. response of the steam generator MSSV's, pressurizer PORVs, and pressurizer PSSVs.

H. MSSV, PORV, and PSSV condition evaluation including an assessment of potential damage which could have occurred as a result of water relief.

7) Evaluate the licensee post-event assessments and root cause evaluation (when available), including causal analyses, extent-of-condition reviews, prompt corrective actions before restart, potential generic implications, and longer term corrective and preventive measures for any equipment or human performance issues.

8) Review compliance with technical specifications and emergency action level entry conditions. Update risk estimates of conditional core damage probability, as appropriate. Review the response of the Emergency Response Data System (ERDS) during the event.

i. Review the adequacy of preventative maintenance and surveillance activities associated with equipment involved in this event.

j. Document the inspection findings and conclusions in a special inspection report in accordance with Inspection Procedure 93812 within 45 days of the exit meeting for the inspection.

SEQUENCE OF EVENTS

Time	Event / Condition
04/17/05 @ 08:29 AM	‘A’ Train SSPS Steam Line Pressure Low SI/MSI signal followed by a reactor trip: First Out alarm: “Steam Line Pressure Low Isolation SI”. C MSIVs closed as expected. **(Not recognized by crew until 0844.)** C 3 MSS-PV20A&C, Atmospheric Dump Valves (ASDVs) open. C 3 MSS-PV20B&D received closed signals via MSI. **(½ of ASDVs shut on ½ MSI.)** C B S/G Safety opens. C The control room crew entered E-0 Reactor Trip/SI emergency response procedure. C At step 4 the crew initiated train B SI. C Terry Turbine steam supplies open and Terry Turbine trips 3 seconds later.
0830	PV20A ASDV closes.
0835	PV20C ASDV closes.
0836	E-0 Step 16 brief, the crew reinforced to the entire control staff that there was no Terry Turbine Aux Feed flow, B S/G Safety was still open and manual initiation of both trains SI was required. Dispatched a PEO to the Terry Turbine who verified that it was not running. Found V5 unlatched and shut. Mech Trip tappet was NOT in overspeed condition. **(Crew continues to evaluate plant conditions, thought stuck S/G Safety caused SI.)**
0839	SR energized.
0839	Field reports verified that B S/G Safety was open.
0840	Pressurizer PORVs commence cycling at RCS pressure of 2350#.
0842	Alert C1 (BA2) declared based on stuck open S/G Safety Relief Valve.
0844	Manual MSI per OP 3272 when the crew diagnoses a partial MSI.
0845	Observed PZR Code Safeties indication. Also noted tailpipe temperatures high.
0845	Red Indication was observed for PZR Safety valves. RCS pressure was not observed to go above 2350#. Observed PORVs open indicating lights and pressure decreasing. **(Control Room Indication issue; PORV cycling caused Safety open indications.)**
0845	Saw PZR pressure cycling at PORV set pressure but no indicating lights on PORVs.
0845	Saw PZR Safety Relief open indication, PZR pressure cycling, but did not see PORV indicating lights cycling.

0850	B S/G Safety reseated. **(Appears that Decay Heat now fully removed by AFW flow; Atmospheric Relief Bypass Valves should be cracked open to lower RCS Temp.)**
0850	The crew decided not to make an E-2 transition based upon SI termination priority and no uncontrolled S/G pressure decrease. **(Discussion occurred between US and SM. Did not meet E-2 entry conditions.)**
0851	EP Message sent.
0854	Determined no S/G tube rupture based on no adverse S/G level trend.
0856	B S/G Safety Relief noticed open again. **(AFW throttled per procedure; RCS temperature increases.)**
0858	Water noticed on Aux Bldg floor. PEO report significant packing leaks on 3CHS*V661 and an MOV that the PEO could not get close enough to identify.
0859	PEO reports that suspect MOV is 3CHS*MV8511B.
0859	Transition from E-0 to ES 1.1.
0900	Reset SI.
0902	PEOs were dispatched to 32-3T to re-energize. The subsequent report from the PEOs noted that 32-3T Alt Source supply light was not lit. Had to replace bulb. Also, the pre-charge light was not lit and the pushbutton appeared to stick.
0905	PEO report - dispatched to observe S/G Safeties. First saw steam flow from B S/G Safety, then C S/G. Very cloudy. Observed flow from 74D and A S/G Safety had a small plume of steam. B and C S/G Safeties were definately open.
0905	Observed Thermal Barrier valves closed on two RCPs. Could not reopen at first based on no Inst Air to Containment. Were reopened later.
0907	Sequence of events recorder indicates last cycle of the PORVs due to the safety injection.
0909	S/G B & C Safeties indicate open. **(AFW reduced as S/G levels recovered.)**
0913	Terminated SI per ES 1.1.
0913	3 MSS MOV-74 A-D partially opened to control temperature and lower secondary pressure in attempts to close Safety valves.
0920	Normal Letdown re-established.
0936	RESET CBI and established outside filtered air to Control building.
0949	Shutdown both EDGs.

0950	Field report that the S/G Safeties were closed. Only steam being released is via 3MSS*MOV74D.
0953	Report from Chemistry that S/G A, B, and C had no activity. Could not get sample from D S/G. **(A and D S/G sample valves were tagged out to meet Tech Spec leakage requirements. A S/G sample valve leaked enough to get a sample; D did not.)**
1000	RX trip signal on D S/G low level came in. AFW to D S/G was increased and level was restored.
1000	Aux Building filter fire alarm came in. Reported running with no discharge path. Filter was shutdown. It was concluded at the time that this did not impact Operability of SLCRS or Aux Building filters.
1000	FR I-1 guidance was used for PZR level control and to re-establish a bubble.
1003	Re-established the bubble at 1800# RCS pressure.
1005	Swapped to B charging. Commenced activities to isolate 3CHS*V661.
1008	RCS pressure was 2050 psia and rising.
1015	Due to concern over action statement on Containment pressure, evaluated starting Containment Vacuum pumps to lower pressure, but decided not to due to concerns that the PRT rupture disk may have ruptured (rupture disk intact throughout event).
1016	PZR level back on scale.
Crew Comment	S/G Safeties appeared to be opening at low pressures.
1019	Maintenance and PEO on scene in the Terry Turbine room, recommend restart. MSV5 opened and Terry Turbine now running.
1025	Turbine Turning gear energized.
1032	3CHS*V659 shut to isolate leak on 3CHS*V661.
1036	B CDS Chiller did not auto restart. Tripped on low condenser pressure when CCP flow restored. C CDS Chiller restarted automatically.
1039	Loading charger 9 on Bat 6.
1044	DWST Level low TS 3.7.1.3.
1050	A Aux Building filter shut down.
1101	Focus brief - pump PRT, RCS samples, Ionics, stabilize PZR level 50 to 85%, Action to stabilize the plant and where we are going.
1116	Started pumping and cooling the PRT.

Management Discussions	Discussion on allowed time to shutdown per TS 3.7.1.1. Action a. Might have only 3 ½ hours to cooldown or the full 12 hours. Decided this was not AOT time and can credit the full time allowed. Discussion included Sarver, Semancik and Smith.
1132	Started looking at shutdown margins for cooldown.
1132	Energized SR audio count rate.
1137	Max CHS flow.
1137	Due to MSI, we did not have the PV20s for post trip cooling. S/G pressure was down close to 1000 psig. Had MSS*74s open to relieve steam to get S/G Safety valves to reseat.
1137	Crew noted unexpected small RCS temperature changes had a large effect on PZR level.
1137	Backed off on the MSS*74s and puffed the S/G Safeties again. **(MSS*74s are MOVs with no % open or % closed indication. Must control pressure by trial and error.)**
1143	Stopped RCS cooldown. Maintain at 550 to 560EF. Relying on MSS*74D, had no preference, this was working so I stayed with it. There was a concern over limitation on cycling the 74s and the limit of 7 cycles for the thermal overloads.
1205	PRT filled to 65 to 85% for cooling.
PEO report	SJAEs had a small leak, pencil stream.
1228	Commenced borating the RCS for Mode 5 Shutdown Required Boron.
1230	B CDS Chiller started.
1301	Transition to OP 3208. Did not complete all steps of ES 1.1, several steps were held open. **(EOP not signed off as complete as late as Friday 4/22.)**
1341	TDAFW Pump stopped.
1450	Decided to use CHS-HCV182 to throttle seal flow vs sending PEO out to locally do this. Got valve 3/4 closed then sent PEO out and reopened 182.
1903	Millstone Unit 3 entered Mode 4 [Hot Shutdown]
1905	ALERT terminated
2345	The NRC exited Monitoring Mode and entered Normal Mode.

SUPPLEMENTAL INFORMATION
KEY POINTS OF CONTACT

Licensee Personnel:

A. Price	Site Vice President
S. Sarver	Director, Nuclear Station Operations and Maintenance
S. Scace	Director, Nuclear Station Safety and Licensing
A. Jordan	Director, Nuclear Engineering
D. Dodson	Manager, Licensing
W. Hoffner	Manager, Nuclear Operations
R. Hoffman	Nuclear Maintenance
C. Maxson	Manager, Nuclear Engineering
T. Kulterman	Acting Manager, Nuclear Training
W. Barton	Supervisor, Licensing
T. Horner	Supervisor, Unit 2 and Unit 3 Initial Operator Training
S. Jackson	Unit 3 Simulator Test Specialist
W. Cote	Unit 3 Simulator Instructor
B. Pinkowitz	Unit 3 Simulator Instructor
C. Tan	Simulator Software Engineer
S.K. Chang	Simulator Software Engineer
M. Galipeau	Instrumentation and Controls Supervisor
P. Chlorite	Generation Test Services Supervisor
D. Asay	Senior Instrumentation and Controls Technician
B. Lasella	Instrumentation and Controls Technician
M. Logan	Instrumentation and Controls Technician
D. Gonsalves	Instrumentation and Controls Technician
P. Luckey	Emergency Preparedness Supervisor
R. Sadler	SRO / ERDS Operator

NRC personnel:

M. D. Sykes	Branch Chief, Team Manager
G. S. Barber	Senior Project Engineer, Team Leader
S. M. Schneider	Senior Resident Inspector
J. G. Schoppy	Senior Reactor Inspector, Division of Reactor Safety (DRS)
D. E. Jackson	Senior Project Engineer, Division of Reactor Projects (DRP)
T. P. Sicola	Reactor Inspector, DRS
R. L. Nimitz	Senior Health Physicist, DRS
W. L. Schmidt	Senior Reactor Analyst, DRS
P. A. Presby	Reactor Inspector, DRS
N. S. Sieller	Reactor Engineer, DRP
D. A. Galloway	Supervising Radiation Control Physicist, State of Connecticut, Department of Environmental Protection, Division of Radiation

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened During this Inspection

05000423/2005012-01	NCV	Failure to Implement Appropriate PMs on the TDAFW Pump Control Valve
05000423/2005012-02	URI	DNC Assessment of Charging System Performance Following the April 17, 2005 Inadvertent SI
05000423/2005012-03	FIN	Improper Event Diagnosis led to E-plan Declaration
05000423/2005012-04	NCV	EOP E-0 Step not performed as required
05000423/2005012-05	NCV	Simulator response did not adequately model MSSV response
05000423/2005012-06	NCV	False or Misleading Control Room Indications
05000423/2005012-07	NCV	Less than adequate corrective actions for potential RCS pressure boundary degradation due to boric acid corrosion)

Closed

050000423/2005002	LER	Inadvertent Reactor Trip and Safety Injection

LIST OF DOCUMENTS REVIEWED

Procedures
MP-26-EPI-FAP01-004 Rev 000-02 - Control Room Emergency Communicator Checklist - 10/14/03
MP-26-EPI-FAP04-015 Rev 000-01 - EOF Emergency Communicator Checklist - 04/01/03
MP-26-EPI-FAP04-013 Rev 002-01 - Manager of Communications (MOC) Checklist - 04/01/03
MP-26-EPI-FAP15-012 Rev 01 - SERO log Sheet
MP-26-EPI-FAP07 Rev 003-06 - Notifications and Communications - 04/08/05

Work Orders
M3 05 06419
M3 05 06418
M3 04 09977

Forms

Manuals
Millstone Unit 3 Technical Specifications (TS)
Millstone Unit 3 Technical Requirements Manual (TRM)
Millstone Unit 3 Final Safety Analysis Report (FSAR)
MSS039C, "Main Steam System", Revision 4, dated 05/12/2003
Nuclear Simulator Engineering Manual NSEM-6.06, "Simulator Scenario Based Testing", Revision 3, 10/21/2003

Condition Reports
CR-05-03734 Lead: MSV5 AFW Pump Turbine Stop Valve
CR-05-03735 Lead: CHS*V661 CHS*MV8511B Packing Leaks
CR-05-03723 Lead: Millstone Unit 3 Reactor Trip & Safety Inje
Open ACEs - Associated with Unit 3 Trip
CR-05-03793 PORVs Leak by
CR-05-03815 Aux Bldg. Filter Hi Temp
CR-05-03889 Operator Training Issues
Open Level N CRs - Associated with Unit 3 Trip
CR-05-03733 S/G Safety Valves Lifting
CR-05-03828 Head Vent Position Issues (Possible RG 1.97)
CR-05-03869 Pzr Safeties Position Issue (RG 1.97)
CR-05-04277 SG Safeties Position Issue (RG 1.97)
CR-05-03876 MP3 MSSV Simulator Blowdown is Lower Than Actual
CR-04-06616
CR-05-03789
CR-05-03936
CR-05-04493

Reports
Simulator Deficiency Report DR-2005-3-0027

Lesson Plans

Simulator Exercise Guides (SEGs)
FS043S, “Rapid Downpower, Turbine Building Steam Leak”, dated 01/22/2000
JIT-05-002D, “MP3 JIT-05-002, MP3 April 17, 2005 Event Review”, Revision 0 (April 2005)

Drawings
UFSAR Figure 7.1-1 Solid State Protectin System Block Diagram. - 7/1997
Technical Schematics for MHTL MC660 series Expandable Dual 4-input Gate type MC661P
Technical Schematics for MHTL MC660 series Expandable Quad 2-input Gate type MC668P
Electrical Characteristics for MHTL MC660 series Expandable Dual 4-input Gate type MC661P
Electrical Characteristics for MHTL MC660 series Expandable Quad 2-input Gate type MC668P
Figure 07.02-01 Sh-08 - Millstone Nuclear Power Station Unit 3 Functional Diagram Safeguards Actuation Signals - 02/1995
Figure 07.02-01 Sh-07 - Millstone Nuclear Power Station Unit 3 Steam Generator Trip Signals - 04/1997

Figure 07.02-01 Sh-13 - Millstone Nuclear Power Station Unit 3 Feedwater Control and Isolation - 03/1998
Figure 07.02-01 Sh-15 - Millstone Nuclear Power Station Unit 3 Functional Diagrams Auxiliary Feedwater Pumps Startup - 03/2003
Figure 07.02-01 Sh-02 - Millstone Nuclear Power Station Unit 3 Functional Diagrams Reactor Trip Signals - 07/1997
Figure 07.02-01 Sh-13 - Millstone Nuclear Power Station Unit 3 Feedwater Control and Isolation - 03/1998
1046F57 - Universal Board Schematic Diagram (1046F57) - 02/24/1970
25212-39001 Sh 7147 - Solid State Protection System Functional Diagram - 3/21/98
25212-39001 Sh 7148 - Solid State Protection System Functional Diagram - 3/21/98
25212-39001 Sh 7149 - Solid State Protection System Functional Diagram - 10/19/98
25212-39001 Sh 7168 - Low Steamline Pressure Digital Logic to the Solid State Protection System Functional Diagram - 5/22/99

Radiological Control Documents

Other Documents
DNC Memorandum - Additional Tin Whisker Inspections - 4/26/2005

OR-05-006 - Event Review Team Report for ‘A’ Train Solid State Protection System Safety Injection Actuation signal resulting in a reactor trip - 4/20/2005

OR-05-008 Rev 1 - Event Review Team Report for ‘A’ Train Solid State Protection System Safety Injection Actuation signal resulting in a reactor trip - 4/27/2005

LIST OF ACRONYMS

ADAMS	Agencywide Documents Access and Management System
ADV	atmospheric dump valve
AFW	auxiliary feedwater
AMF	alternate minimum flow
ASME	American Society of Mechanical Engineers
BACC	boric acid corrosion control\
CAN	Citizens Awareness Network
CFR	Code of Federal Regulations
CHG	charging
CR	condition report
CR	control room
CRC	Citizens Regulatory Commission
DNC	Dominion Nuclear Connecticut, Inc.
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
DSO	Director of Site Operations
EAL	emergency action level
ECCS	emergency core cooling system
EDG	emergency diesel generator
EOC	extent of condition
EOP	emergency operating procedure
ERT	event review team
ERDS	emergency response data system
FIN	finding
FSAR	Final Safety Analysis Report
GL	Generic Letter
GPM	gallons per minute
HEPA	high efficiency particulate air
HHSI	high head safety injection
I&C	instrumentation and controls
IT	information technology
IMC	Inspection Manual Chapter
IRC	Incident Response Center
LER	Licensee Event Report
LERF	large early release frequency
MDAFW	motor driven auxiliary feedwater
MSI	main steam isolation
MSIV	main steam isolation valve
MSSV	main steam safety valve
NCV	non-cited violation
NEAC	Nuclear Energy Advisory Council
NRC	Nuclear Regulatory Commission
ODCM	Offsite Dose Calculation Manual
OE	operating experience
PARs	publicly available records
PM	preventative maintenance
PORV	power operated relief valve
PRT	pressurizer relief tank
RCE	root cause evaluation
RCIC	Reactor Core Isolation Cooling

RCS	reactor coolant system
RG	Regulatory Guide
RHR	residual heat removal
RNO	response not obtained
RO	reactor operator
RTD	resistance temperature detector
RWST	refueling water storage tank
RV	relief valve
SAPHIRE	Systems Analysis Programs for Hands-on Integrated Reliability Evaluations
SM	Shift Manager
SORC	Station Operations Review Committee
SSCs	structures, systems and components
SDP	significance determination process
SG	steam generator
SI	safety injection
SPAR	Standardized Plant Analysis Risk
SRA	Senior Reactor Analyst
SSPS	solid state protection system
STA	Shift Technical Advisor
TDAFW	turbine driven auxiliary feedwater
TS	technical specification
URI	unresolved item
US	Unit Supervisor