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OFFICE OF NUCLEAR REACTOR REGULATION

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Inspectors:	Richard P. McIntyre, ICAVP, Team Leader ICAVP, ADT, NRR Brian Hughes, Operations Inspector, ICAVP, ADT,NRR Paul Narbut, Operations Inspector, ICAVP, ADT, NRR James Houghton, Mechanical Engineer, ICAVP, ADT, NRR Robert Quirk, I&C Engineer, Contractor*
Approved by:	John A. Nakoski, ICAVP Program Coordinator Millstone Independent Corrective Action Verification Program Inspections Associate Director for Technical Review Office of Nuclear Reactor Regulation

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EXECUTIVE SUMMARY

From August 10 through September 3, 1998, a team from the U.S. Nuclear Regulatory Commission's (NRC's), Independent Corrective Action Verification Program (ICAVP) Inspection Oversight staff of the Office of Nuclear Reactor Regulation, in accordance with the guidelines outlined in SECY-97-003, "Millstone Restart Review Process," conducted a Tier 2 Accident Mitigation Systems inspection at Millstone Unit 2 and at the offices of Parsons Power Group Inc. (Parsons), the Unit 2 ICAVP contractor.

The objectives of the Tier 2 inspection were to (1) independently assess the licensee's ability to identify and resolve licensing-basis deficiencies, focusing mainly on the period of the licensee's Configuration Management Plan (CMP) implementation; (2) verify that critical design characteristics (CDCs) of systems relied upon to mitigate the consequences of accidents analyzed in Chapter 14 of the Final Safety Analysis Report (FSAR) were consistent with those used in the design of the mitigation systems; and (3) assess the effectiveness of the Tier 2 aspects of Parsons' ICAVP. The Parsons Tier 2 reviews were designed to be narrower in scope than those performed on the Tier 1 systems selected by the NRC. The Tier 2 reviews began after the selected CDCs were approved by the NRC. Parsons then determined if the selected CDCs could be met by these systems through a review of documents and information such as design requirements, supporting accident analyses and calculations, test procedures and results, surveillance procedures and results, emergency, abnormal, and routine operating procedures, and various corrective action documents. This review provided a measure of confidence that the licensee's accident mitigation systems were adequately designed and tested and would perform as assumed in the accident analyses.

The team thoroughly reviewed certain important aspects of accident mitigation systems. The NRC's Tier 2 team inspection performed a focused functional review of the systems involved in the mitigation of two accident scenarios: the main steam line break (MSLB) analyses for the containment (FSAR Section 14.8.2.1) and the reactor coolant system (RCS) (FSAR Section 14.1.5); and the small-break loss-of-coolant accident (SBLOCA) (FSAR Section 14.2.7). The team selected a sample of CDCs related to the mitigation systems for these two accidents and performed a systematic verification that the design basis, construction, operation, training, and testing were consistent with the assumptions made in the accident analyses.

The team reviewed approximately 92 CDCs for the two accidents selected. Based on results of this sample review, the team determined that the input data for the accidents analyzed in Chapter 14 of the FSAR appeared consistent with the performance of the mitigation systems and that the accident analyses should be adequate to maintain the Unit 2 design and licensing bases.

The team found that the Parsons Tier 2 ICAVP review was conducted in accordance with the NRC-approved ICAVP Audit Plan and project procedures and that the reviews were conducted in a thorough, detailed and critical manner. Generally, the findings identified by the team were consistent with the findings identified by the Parsons ICAVP. For example, Parsons identified similar problems with the use of procedures in the "DO NOT USE" status, and the calibration of measuring and test equipment.

The team identified one violation during the site inspection. The violation involved multiple examples of the failure to translate design basis requirements into plant procedures. This violation is considered equivalent to an ICAVP Significance Level 3 finding. The number of issues identified in this violation appears to be indicative of a configuration control weakness in the translation or reconciliation of the accident analyses inputs and results with station procedures and other supporting engineering analyses that form the bases for the system design.

The team also concluded that the licensee had identified and resolved many important CMP deficiencies and was implementing several improvements to the program by issuing condition reports (CRs) and action requests (ARs) in response to the team's findings. In accordance with NRC policy, when the team identified a problem that the CMP had already identified and that had been or was being corrected, the team did not issue a violation. Also, the team observed a number of strengths and good practices. For example, licensee personnel responded well to the team's questions and concerns, the Unit 2 design engineering group exhibited sound technical knowledge, and the licensee demonstrated relatively good information retrieval capabilities.

1.0 Background

On August 14, 1996, the U.S. Nuclear Regulatory Commission (NRC) issued a Confirmatory Order (Order) to the Northeast Nuclear Energy Company (NNECO or the licensee) requiring completion of an Independent Corrective Action Verification Program (ICAVP) before the restart of any Millstone unit. The Order directed the licensee to obtain the services of an organization independent of the licensee and each facility's design contractor to conduct a multidisciplinary review of Millstone Units 1, 2, and 3. On July 15, 1997, the staff approved NNECO's selection of the Parsons Power Group Inc. (Parsons) to perform the ICAVP for Millstone Unit 2. This inspection focused on the Tier 2 aspects of the ICAVP.

In a Commission paper, SECY-97-003, "Millstone Restart Review Process," dated January 3, 1997, the staff described the Millstone restart review process. To provide the necessary assurance to support a unit restart decision, the staff's expectation, described in SECY-97-003, was that the ICAVP would encompass the aspects of configuration control through a three-tiered approach.

The objective of the Tier 2 review was to provide assurance that the performance of accident mitigation systems agreed with that input into the accident analyses. To evaluate the capability of accident mitigation systems subject to the Tier 2 review, the contractor selected design characteristics of these systems that were specified in Chapter 14 of the FSAR and submitted them to the staff for approval. The ICAVP contractor evaluated the NRC-approved CDCs by performing a review of documented surveillance tests, plant startup tests, or a critical review of design calculations, specifications, vendor documents, and drawings to assess conformance with the system performance input to the accident analyses.

1.1 Scope of NRC Review

The NRC's Tier 2 inspection consisted of a thorough review of two postulated accidents analyzed in the FSAR. The team selected a sample of critical functions performed by the mitigation systems and systematically verified that the design basis, construction, operation, training, and testing were consistent with the assumptions made in the accident analysis. The NRC's Tier 2 inspection focused on the main steam line break (MSLB) analyses for the containment (FSAR Section 14.8.2.1), and the reactor coolant system (RCS) (FSAR Section 14.1.5); and the small-break loss-of-coolant accident (SBLOCA) (FSAR Section 14.2.7).

The team selected a sample of CDCs for the accidents scenarios chosen and reviewed mechanical systems, instrumentation and control, and plant operations aspects of the CDCs. By independently evaluating approximately 92 of the Tier 2 CDCs reviewed by the contractor, the team gained insights in two areas: (1) whether the contractor implemented the ICAVP in a critical and thorough manner; and (2) whether the licensee's CMP adequately corrected the Tier 2 aspects of its configuration management problems. The team also observed operators in the plant simulator to observe their actions in response to the MSLB and SBLOCA accident scenarios with an emphasis on the times required to perform operator actions assumed in the analyses.

Finally, the team went to Parsons' offices in Reading, PA, and compared its Tier 2 findings from the site inspection and the results of the Parsons review. While at Parsons' offices the team also assured that Parsons had followed its planned evaluation of the CDCs for the selected accident scenarios in an acceptable manner.

Appendix C to this report lists the initial or bounding conditions, or the CDCs and associated design parameters reviewed by the NRC inspection team.

2.0 Mechanical

2.1 Millstone Site Observations and Findings

The team found that for the majority of CDCs sampled for the mechanical systems and components discipline had been successfully translated into plant procedures or were in the process of being translated. However, one example of inadequate translation of the design basis into plant procedures was identified during the mechanical review.

The CDCs used in the revised MSLB containment accident analyses and SBLOCA analysis are considered design basis characteristics. The team's review of the validity of the MSLB and SBLOCA CDCs determined that there was a failure to translate these design basis characteristics into plant procedures.

As an example, the MSLB containment accident analysis CDC for containment free net volume was assumed to be 1,899,000 cubic feet. However, Engineering Procedure EN-21065, Rev. 3, "Containment Mass Tracking," dated April 3, 1998, does not include an acceptance limit to assure that this CDC continues to be valid.

10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires that, "measures shall be established to assure that the applicable regulatory requirements and the design basis...are correctly translated into specifications, drawings, procedures, and instructions." The failure to correctly translate the design basis, as identified in the FSAR Chapter 14 accident analyses, into plant procedures that include an acceptance limit in EN-21065 assuring that the containment free net volume continues to be valid, is a violation of the design control requirements of 10 CFR 50, Appendix B, Criterion III. This issue is considered equivalent to an ICAVP Significance Level 3 finding. **(VIO 50-336/98-213-01, Example 1)**

Millstone personnel agreed that there was an apparent weakness in the flow of information from new or revised analyses into plant procedures. CR M2-98-2355 was written to evaluate and address this weakness as it applies to this and other examples, and to the generic process for handling this type of technical information, as described in the Design Control Manual (DCM).

The team also made two observations about the in-process translation of the design basis into plant procedures:

(1) Inadequate Translation of Design Basis into Plant Procedures for In-Process Tracking Commitments

The licensee issued AR-98008632-01 to track the need for providing design basis information for pump Inservice Testing (IST) procedures. Although this tracking commitment partly validated CDCs applicable to pump IST degradation limits, it did not assure that the system operability surveillance procedure (or its equivalent) would validate the CDC flow requirements for the containment spray, charging, and auxiliary feedwater systems (usually a non-IST function).

(2) Untimely Update of The Safety Functional Requirements (SFR) Design Basis Document.

When the System Design Basis Document Packages (DBDPs) were retired and replaced by System Design Summary documents, the SFR document was retained as a controlled and maintained DBDP. In reviewing the validity of CDCs for the MSLB and the SBLOCA accident analyses, the team found that the SFR did not reflect system-specific analyses and modifications performed in support of the updated accident analyses. Although the present design control process (per the DCM) provides for the revision of the SFR, the lack of timeliness is considered a potential vulnerability in the design control process, especially in the translation of the design basis into plant procedures.

CR M2-98-2355 as described above, was written to evaluate and address the weakness as it applies to the inspection examples and the DCM process. The CR also includes an effectiveness review to ensure that key Safety Functional Requirements Manual assumptions are reflected by existing plant configuration and operating practice.

2.2 Observations and Findings at Parsons

The team identified a minor inconsistency in Parsons' implementation of the ICAVP Audit Plan and Project Procedure, PP-02, "Accident Mitigation Systems Review," as currently documented and as approved by the NRC staff. The inconsistency was in the validation of CDCs associated with the systems being reviewed by the Parsons Tier 1 Group. During discussions with Tier 1 and 2 staff, the team determined that the validation of CDCs for Tier 1 systems were being performed using a more informal process than described in the NRC-approved ICAVP Audit Plan and PP-02. However, even though the interface with the Tier 1 group was not as formal as specified in PP-02, the team concluded, after further discussions with both Tier 1 and 2 staff, that the process was still effective in conducting the Tier 2 CDC validation.

Parsons was requested to assure that the process being used did not reduce the effectiveness of the Audit Plan and the Tier 2 process documented in PP-02. Further, Parsons was requested to revise the Audit Plan and PP-02 to accurately describe the process utilized for interaction between the Tier 1 and Tier 2 groups to validate the CDCs for the affected Tier 1 systems.

2.3 Conclusions

The team concluded that for plant modifications there were no safety significant concerns with the licensee's design control process. However, the specific finding on the lack of translation of accident analyses inputs to plant procedures was a programmatic weakness that had not been adequately addressed in the DCM. The DCM was mainly used by the licensee for the design control of plant modifications. This programmatic weakness effected Unit 2 substantially more than Unit 3 because the licensee had reanalyzed most of the accidents described in Chapter 14 of the Unit 2 FSAR. Millstone engineering personnel agreed that there was an apparent weakness in the flow of information from new or revised analyses into plant procedures. CR M2-98-2355 was written to evaluate and address this programmatic weakness.

The team concluded that Parsons' methodology for reviewing and validating the CDCs in plant procedures was acceptable for mechanical systems and components and that Parsons conducted the review in a comprehensive and detailed manner.

3.0 Instrumentation and Controls (I&C)

3.1 Millstone Site Observations and Findings

For the CDCs sampled, the team determined that because of the recently revised analyses, most of the CDCs had not been successfully translated into active plant procedures and acceptance criteria. Only 10 of 39 I&C related CDCs were completed and validated by the team. The team identified five CDCs not fully implemented in plant procedures but validated by Parsons. These are associated with control element assembly (CEA) drop time and feedwater isolation valve closure time, as discussed further in Sections 3.1.1 and 3.1.2 below.

3.1.1 Control Element Assembly Drop Time

The MSLB and SBLOCA analyses assumed that CEA-holding coils would release the rods 0.5 seconds after power to the coils is interrupted and that the rods would be 90 percent inserted (from 180 steps to 18 steps) in the next 2.25 seconds for a total time from power removal until rods were 90 percent inserted of 2.75 seconds. TS Limiting Condition for Operation (LCO) 3.1.3.4, "CEA Drop Time," requires a fully withdrawn CEA drop time of less than or equal to 2.75 seconds from when electrical power is interrupted to the CEA drive mechanism until the CEA reaches its 90-percent insertion position. The TS does not address the two constituents of this time interval described in the accident analysis.

The licensee used Surveillance Procedure (SP) 21010, Rev. 5, "CEA Drop Times (IPTE)," to satisfy TS 4.1.3.4 testing requirements. The procedure permitted testing one group of rods at a time with the results monitored by the plant process computer (PPC); the acceptance criterion was that the rods must be fully inserted within 2.65 seconds; otherwise individual rods must be re-tested with a measuring and test equipment (M&TE) strip chart recorder. During group rod testing a single rod in the group was also monitored by an M&TE recorder and the acceptance criterion for this rod was relaxed to the TS limit, i.e., ≤2.75 seconds from power removal until 90-percent insertion. Neither the group drop test nor the individual rod test measured the time between removing power to the CEA and when rod motion began, nor did they measure the time between the start of rod motion and adequate rod insertion. The team noted this information was available on the strip chart recorder records but was not measured.

The failure to translate design requirements (CEA coil release times of ≤0.5 seconds and rod motion ≤2.25 seconds) into plant test procedures is another example of failure to translate design requirements into plant procedures, contrary to the requirements of 10 CFR 50, Appendix B, Criterion III, "Design Control." This issue is considered equivalent to an ICAVP Significance Level 3 finding. **(VIO 50-336/98-213-01, Example 2)**

The licensee evaluated actual data from the 12 individual rods recorded when rod drop testing was last performed in 1995, and reported the coil release times varied from 0.12 to 0.22 seconds, well within the accident analysis assumption. The licensee initiated CR M2-98-2412 to evaluate whether coil release times needed to be measured for each CEA after refueling.

The team also reviewed the recommended CEA gripper coil testing in the CEA Vendor Technical Manual (VTM) VTM2-150-006A, Rev. 006D, "Unit 2 Magnetic Jack Type Control Element Drive." The team noted the licensee was not performing the maintenance recommended in Sections 6.1.1.4, 6.1.2.1.3, and 6.1.2.2.2 of the manual. The licensee initiated

CR M2-98-2399 to investigate why the vendor-recommended testing had not been incorporated into the control element drive mechanism (CEDM) maintenance procedures. Further NRC review of this issue will be tracked as an inspector followup item (IFI). **(IFI 50-336/98-213-02)**

3.1.2 Feedwater Isolation Valve Closure

The SBLOCA analysis assumed the feedwater (FW)-regulating valve would not close until 30 seconds after the reactor tripped. This ensures that adequate heat is removed from the primary plant. In Instrument and Control Procedure (IC) 2426A, Revision 7, "Feedwater Control System Calibration," Attachment 5, "Feedwater Control Calibration Data Sheet," Step 4.16.134.a the acceptance criterion was 30 ±2 seconds. The main FW-regulating valve could close in less than the 30 seconds assumed in the accident analysis.

The team concluded that the failure to translate this design requirement into plant procedures was of low significance from an accident analysis standpoint. As stated in Section 3.2, Parsons plans to evaluate this further during its review of the new SBLOCA analysis.

3.1.3 Setpoint Program

Engineering Work Request (EWR) M2-97-061, "Setpoint Program," was a large project to address the effects of harsh environments on RPS, ESF, emergency operating procedures (EOPs), and other TS-related instrument setpoints. The licensee stated it was not committed to Regulatory Guide (RG) 1.105, Rev. 1, "Instrument Setpoints for Safety Related Systems," that would have required the use of accepted statistical methods to account for measurement and instrument uncertainties for RPS- and ESF-actuated features. The team reviewed approximately 10 RPS and ESF setpoint calculations revised under this program.

The team noted that the calculations were a significant improvement over the setpoint calculations used to license the plant and were consistent with licensee specification SP-ST-EE-286, Rev. 6, "Guidelines for Calculating Instrument Uncertainties." SP-ST-EE-286 is a site-wide procedure used to ensure RPS and ESF setpoint methodologies were consistent with RG 1.105. The team concluded that even if Unit 2 was not committed to RG 1.105, the licensee was required to follow SP-ST-EE-286 at Unit 2.

The licensee was also participating in a recent initiative of the Combustion Engineering Owners Group (CEOG) to identify the engineering and analytical limits and bases for non-RPS and ESF actuation system (ESFAS) setpoints. These setpoints were not addressed by RG 1.105 but the licensee acknowledged it was important to understand which TS parameters were sensitive to instrument uncertainties.

The licensee stated it was reviewing several DRs associated with instrument uncertainties, including DR-130, "Incorrect Value Used for M&TE Term in Calculations," and DR-364, "Discrepancies in Setpoint and Loop Uncertainty Analyses for HPSI," to determine if the concerns were valid and the impact on the calculation results. The team found that this review was being completed in a thorough and systematic manner.

The team identified an error in SP 2402B, Rev. 6, "Pressurizer Pressure Calibration," Step 2.3.1 that provided the option of using a 0-2500 or 0-3000 psig gauge to calibrate the 1000-2500 psia pressure transmitters PT-102 A, B, C, and D pressurizer pressure instruments. M&TE such as these pressure gages can exhibit nonlinear behavior at the high and low extremes, and this would not necessarily be detected during normal measuring and testing equipment (M&TE) calibrations. Industry practice is to not use the extremes of M&TE when calibrating important-to-safety devices.

The team questioned the use of a 0-2500 psig gage for calibrating PT-102A, B, C, and D because it may not provide adequate margin beyond the calibrated instrument range. As a result of this concern, the licensee added AR 98010434 to existing M&TE CR M2-98-1500. This AR will result in a review of all calibration procedures for RPS and ESFAS setpoints to ensure the calibration range is enveloped and to revise procedures as required. Further NRC review of this issue will be tracked as an IFI. **(IFI 50-336/98-213-03)**

M&TE has been identified as a problem at Millstone in the past. M&TE issues were identified as a Unit 1 Significant Items List (SIL) item although it was a site-wide problem. The various M&TE issues raised by Parsons in DRs, the existence of a Unit 1 SIL item, and related questions raised by the team demonstrate a need for continued improvement in the Unit 2 M&TE program.

3.2 Observations and Findings at Parsons

The team identified some minor differences between the Parsons' CDC validation and the team's effort. These were the result of changes to the licensee's documents between the time Parsons reviewed the available data and when NRC reviewed the data. These minor differences include the proposed RPS and ESF TS setpoint changes and the status of SP 2604P as a "DO NOT USE" document. One of the differences noted by the team was the CEA drop time test CDCs. Parsons stated that the licensee did not monitor the coil release and actual rod travel times, but Parsons determined this was acceptable based on a review of other data such as post-trip reports. The post-trip data reviewed showed neutron flux decreasing 0.4 seconds after the reactor trip signal, and Parsons interpreted this as evidence that the coils released the rods in less than 0.5 seconds. Parsons also stated that if the coils were not releasing the rods within the 0.5 seconds, the licensee would have experienced problems with the group drop time criterion of ≤2.65 seconds. As there was no evidence that this time was being exceeded, Parsons concluded the coil release and rod travel times were being met.

Parsons was unable to review IC 2426A when evaluating the FW-regulating valve closure after a reactor trip because the status of the procedure was "DO NOT USE." Parsons reviewed an alternate source, M2-EV-98-0017, "Failure Modes and Effects Evaluation for Feedwater Regulating Valve Bypass and Control Circuit Millstone Unit 2," that stated the FW-regulating valves would close in 30 seconds. Parsons indicated it would evaluate this CDC again while reviewing the new SBLOCA analysis report.

3.3 Conclusions

In general the I&C CDCs were not included in current approved-for-use plant procedures, but this was primarily because the setpoint program was being revised and the ESF time response procedure was in a "DO NOT USE" status. It is the team's understanding that these procedures will be updated prior to entry into the operating mode for which they are necessary. The NRC will verify that "DO NOT USE" procedures have been appropriately revised and returned to approved-for-use status as necessary to support changes of operating mode as part of the closure process for the Unit 2 SIL item No. 8, "Procedure Adequacy/ Procedure Upgrade Program."

The failure to translate the CEA coil release and rod motion times into plant procedures is the second example of a violation of the requirements of 10 CFR 50, Appendix B, Criterion III, "Design Control."

The team concluded the Parsons review of the I&C-related CDCs was adequate and sufficiently detailed.

4.0 Operations

4.1 Millstone Site Observations and Findings

For the CDCs sampled, the team determined that, in most cases, the parameters had been successfully translated into plant procedures and acceptance criteria.

The team noted two exceptions:

(1) As discussed in Section 4.1.4, in many cases the team had to evaluate the requirements and criteria in procedures marked "DO NOT USE." The team considered the parameters verified with these procedures as provisionally valid.

(2) In some cases, Parsons had identified a DR pertinent to the parameter. In these cases, the team concluded the parameter was valid (successfully implemented) with the exception of the DR resolution. The DRs in the operations area concerned issues such as instrument accuracy.

Additionally, the team identified two parameters that did not appear to be successfully implemented in plant procedures.

4.1.1 Feedwater Regulating Bypass Valves

The MSLB analysis for containment, ABB-CE calculation 006-ST97-C-024, Rev. 0, assumed that at power levels greater than 25 percent, the FW-regulating bypass valves would be closed. If the valves were open they might fail to close (as the presumed single failure). The open valve would provide additional feedwater from upstream piping and components, and therefore would potentially exacerbate the peak containment pressure and temperature.

The team noted that it is a common operating practice to use the bypass valves to control steam generator levels (at high power levels) when the main feedwater regulating valves are not functioning properly. In these cases, the main valve is put in manual and the bypass valve is used to control level. The licensee stated that, in the past, they had utilized this practice and placed the feedwater regulating bypass valves in manual. The team noted that the operating procedure for the feedwater system, OP-2203, Revision 13, "Plant Startup," did not have a prohibition against using the bypass valves at power levels greater than 25 percent.

The failure to have a procedural requirement to keep the FW-regulating bypass valve closed above 25 percent power (a critical parameter assumed in accident analysis) is considered an example of a violation of the requirements of 10 CFR Part 50, Appendix B, Criterion III, "Design Control." This issue is considered equivalent to an ICAVP Significance Level 3 finding. **(VIO 50-336/98-213-01, Example 3)**

The licensee issued CR M2-98-2355, dated August 14, 1998, to document the problem and its resolution. The licensee stated that it considered the condition potentially reportable to the NRC as operating in a condition outside of the design bases. The licensee stated that it would make its reportability determination within 30 days and make a report if appropriate.

4.1.2 Steam Generator Operating Level

The MSLB analysis for containment, ABB-CE calculation 006-ST97-C-024, Rev. 0, assumed that the initial steam generator level was at 70-percent narrow-range (NR) level. The team noted that operating procedure OP 2203, Revision 13, "Plant Startup," allowed steam generator allowed normal operating levels up to 75 percent NR. The increased initial inventory provides more feedwater in the faulted generator, and therefore could potentially exacerbate the peak containment pressure and temperature.

The team referred the matter to NRC technical staff, who stated that the more appropriate approach would have been to use the more conservative input value of 75 percent. However, the staff stated that the analytical methodology used to determine the resulting containment pressure and temperature after an MSLB contained sufficient conservatism such that it is unlikely that the consequences of the accident were underestimated using the nominal value. Also, from a risk-informed perspective, in addition to the low probability of a complete break of a main steam line, it is unlikely that an MSLB would occur when all the important parameters are at the worst-case values for containment pressure and temperature. Based on the above, the team concluded no further review of this issue was necessary.

4.1.3 Auxiliary Feedwater (AFW) Enthalpy CDC

The MSLB CDC for the maximum AFW enthalpy is based on 100°F. The latest revision of OP 2319B, "Condensate Storage and Surge System," states the maximum allowable condensate storage tank (CST) temperature is 120°F. Operations Form 2669A-1, "Unit 2 Turbine Building Rounds, Outside Areas," also indicates a maximum allowable CST temperature of 120°F. The CST is the water supply for the AFW pumps.

The failure to translate the appropriate AFW enthalpy temperature from the accident analysis into the operating procedure is another example of an improper translation of accident assumptions and design basis into plant procedures, contrary to the requirements of 10 CFR Part 50, Appendix B, Criterion III, "Design Control." This issue is considered equivalent to an ICAVP Significance Level 3 finding. **(VIO 50-336/98-213-01, Example 4)**

4.1.4 Use of "DO NOT USE" Procedures

During the review of operations procedures in the Unit 2 control room the inspection team found that many of emergency operating and power operations procedures were administratively classified as "DO NOT USE," based upon having exceeded their biennial review dates. TS Section 6.8.1, "Procedures," states, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Appendix A of RG 1.33 (February 1978). Appendix A of RG 1.33 includes procedures for power operation, procedures for emergencies and other significant events (including plant fires), procedures for surveillance tests, and procedures for maintenance.

TS 6.8.2.c states that each procedure of Specification 6.8.1 shall be reviewed by the Plant Operations Review Committee (PORC) or Station Operations Review Committee (SORC) and shall be approved by the Unit 2 Unit Director or Senior Vice President and Chief Nuclear Officer

(CNO)-Millstone, or be reviewed and approved in accordance with the Station Qualified Reviewer Program, before implementation. TS 6.8.2.c also requires that each procedure be reviewed periodically, as prescribed in administrative procedures.

As of August 21, 1998, the licensee had not maintained current all of the procedures recommended in Appendix A of RG 1.33, failing to review certain procedures periodically, as required by TS 6.8.2.c. Specifically, station procedure DC 1, "Administration of Procedures and Forms," Rev. 7, dated August 12, 1998, which sets forth requirements for periodic review of procedures, allows procedures to be designated as "DO NOT USE" if the required biennial review cannot be completed before the biennial review expiration date. As of August 21, 1998, the licensee had designated 144 procedures as "DO NOT USE" because the biennial reviews had not been completed. These procedures included the AOP 2579 Fire Procedure series and the emergency operating, power operations, surveillance, and maintenance procedures. Station procedure DC 1, page 53 of 104, states that the "DO NOT USE" process is not applicable to procedures dealing with medical or fire emergencies.

The licensee decided to defer the required reviews and updates because of limited resources and because most of the station accident analyses were being updated with the latest design information. The NRC staff understands that Unit 2 had been defueled and was in an extended shutdown when procedures exceeded their biennial review date and that information from the revised accident analyses will need to be factored into many of these procedures. The team did not observe any "DO NOT USE" procedure being used (other than simulator training) for safety-related activities. Further, none of the procedures designated as "DO NOT USE" are applicable or necessary with the plant defueled.

The use of "DO NOT USE" on procedures has been an issue in the past with Millstone Unit 2. A 1991 violation, 50-336/91-81-12, identified that more than 100 station procedures had not received a biennial review. A 1993 violation, 50-336/93-20-01, identified more than 200 station procedures had not received their biennial review. Also, the facility's internal quality assurance (QA) organization made similar findings. In March 1994, in response to the 1993 violations, the station issued DC-1, Rev. 1, (biennial review) that allowed procedures that had not received their biennial review to be placed in a "DO NOT USE" status to ensure that before use, the procedures would receive the required reviews. The facility was in full compliance in June 1996.

The failure to maintain current some 144 procedures that were identified as "DO NOT USE" because they exceeded their biennial review dates, is considered a violation of RG 1.33 and station TS 6.8. This group of procedures included the AOP 2579 fire procedure series and emergency operating, power operations, surveillance, and maintenance procedures. TS 6.8 requires procedure review and management approval and neither is mode dependent. However, since none of the procedures designated as "DO NOT USE" were required for current plant conditions, i.e., no fuel in the reactor vessel, the team considered the significance of this violation to be below the level of significance of a Severity Level IV Violation. Therefore, in accordance with Section IV of the NRC Enforcement Policy, this is considered to be a Non Cited Violation. **(NCV 50-336/98-213-04)**

Also, during the simulator demonstration at the training facility, the team identified that the EOPs being used in the simulator for licensed operator training were in draft status that was a different revision than those in the Unit 2 control room binders or as identified in site nuclear records. These draft procedures have not been reviewed and approved by the appropriate site management. Since only approved procedures are allowed for licensing actions, the lack of approved procedures prevents the NRC from administering license operator examinations and is a significant training concern.

CR M3-98-3781 was written to evaluate and address the appropriateness of the "DO NOT USE" process as it applies to all station procedures and CR M2-98-2414 was written to address "DO NOT USE" status of procedures used for licensed operator training and examinations.

4.1.5 Observation of Training Simulator Demonstration

The team observed an operating crew respond to both an MSLB and a LOCA scenario on the Unit 2 simulator at the Millstone Training Facility. The team also reviewed the EOPs and performed plant tours. The team determined that the operating crew was very professional, demonstrated a thorough knowledge of the EOPs, and exhibited good communication skills during the response to the accident scenarios.

The review of EOPs involved a verification that the accident analysis assumptions, design bases, licensing bases, and plant operation conformed with each other when appropriate. The team determined that EOPs 2532, Rev. 15, "Loss of Primary Coolant," and EOP 2536, Rev. 14, "Excess Steam Demand," were clear, concise and easily readable. EOPs 2532 and 2536 are symptom-based procedures derived from the generic CEOG procedure guidance. The team found that the licensee appropriately modified the generic CEOG procedure to agree with the configuration of Unit 2. A step deviation document was prepared that described in detail why and where a deviation from the CEOG-approved procedures existed. In general, the deviations were a result of inserting Unit 2 plant-specific information for components. Plant-specific instrument setpoints were developed using the setpoint methodology provided in the generic CEOG procedure development documents. In addition a setpoint upgrade program has been completed and incorporated into the Unit 2 EOPs.

4.2 <u>Observations and Findings at Parsons</u>

For the case of the FW-regulating bypass valve, the Parsons engineers stated that according to the information they had, OP-2203, "Plant Startup," did not specifically describe the use of the bypass valves at high power levels. However, since the bypass valves are typically closed above 25-percent power, the Parsons reviewer was unaware of the operations practice. The Tier 2 program did not include an operations oriented review of each critical assumption or parameter. Further, it is difficult to anticipate possible operator actions not precluded by procedures.

4.3 <u>Conclusions</u>

Although the team noted two instances in the operations area in which the licensee failed to adequately translate design requirements into operating procedures, overall the team concluded that the licensee had adequately translated design bases requirements into plant procedures. Further, team found that the licensee trained its operators on EOP implementation and that the EOPs were consistent with the current design and licensing bases. However, the team also determined that the licensee's deferral of the biennial review of EOPs, making "DO NOT USE" was contrary to the requirements of TS 6.8.1. This decision by the licensee was based on the fact that the majority of the accident analyses were still a in progress and to conserve resources during the current extended outage. Further, the EOP revision used in the simulator (Rev. 17) did not match the revision used in the control room or in the licensee's procedure tracking program. Without approved procedures in place to support licensed operator training, the NRC cannot administer licensed operator examinations.

The team considered that the Parsons review was comprehensive and at the appropriate level of detail. Although Parsons did not identify that the operating procedures did not preclude operation with the feedwater bypass valves open at greater than 25 percent power, this is not a typical nor anticipated operating configuration.

5.0 Entrance and Exit Meetings

The team conducted an entrance meeting on August 10, 1998, for the Millstone Unit 2 Tier 2 inspection. On August 31, 1998, the team conducted an entrance meeting at the Parsons offices in Reading, Pennsylvania. During each of these meetings, the team discussed the scope, duration, and expected support requirements for each phase of the inspection.

On October 6, 1998, the team leader conducted an exit meeting at the Millstone Training Facility that was open for public observation. During this meeting, the team's findings and observations were discussed. A partial list of attendees is given in Appendix B.

Appendix A

List of Apparent Violations, Unresolved Items, and Inspector Followup Items

This report categorizes the inspection findings as violations (VIO), apparent violations being considered for escalated enforcement (EEI), unresolved items (URIs), or inspector followup items (IFI) in accordance with Chapter 610 of the NRC Inspection Manual. An apparent violation is a matter about which the Commission has enough information to conclude that a violation of a legally binding requirement has occurred. The violation is classified as apparent until the NRC assigns a severity level, and the licensee is given a chance to respond to the NRC's determinations. A URI is a matter about which the Commission requires more information to determine whether the issue in question is acceptable or constitutes a deviation, nonconformance, or violation. The NRC may issue enforcement action resulting from its review of the identified URIs. An IFI is a matter for which additional information is needed that was not available during the inspection.

Item Number	Type	Section(s)	Status	Title
50-336/98-213-01	VIO	2.2.1 3.1.1 4.1.1 4.1.2	Open	Failure to translate accident analyses assumptions, inputs, or results into plant procedures contrary to 10 CFR Part 50, Appendix B, Criterion III.
50-336/98-213-02	IFI	3.1.1	Open	Vendor recommended testing not incorporated in control element drive mechanism maintenance procedures
50-336/98-213-03	IFI	3.1.3	Open	Use of 0 -2500 or 0 -3000 psig gauge to calibrate 1000 -2500 psia pressure transmitters PT-102 A, B, C, and D, pressurizer pressure instruments.
50-336/98-213-02	NCV	4.1.4	Open	Utilization of "DO NOT USE" classification for procedures contrary to RG 1.33 and TS 6.8.

Appendix B
Entrance and Exit Meeting Attendees
(Partial List)

NAME	ORGANIZATION
Northeast Nuclear Energy Company	
M.Bowling	Unit 2 Recovery Officer
J. McElwain	Unit 2 Recovery Officer
P. Loftus	Manager, Regulatory Affairs
M. Ahern	Manager, Design Engineering
D. Harris	Coordinator, Regulatory Compliance
J. Fougere	Manager, ICAVP
R. Necci	Director, Configuration Management Program
R. Laudenat	ICAVP Program Director, Regulatory Affairs
S. Brinkman	Director, Unit 2 Engineering
R. Boehling	Asst. Director, Unit 2 Engineering
F. Mattioli	Supervisor, ICAVP
J. Price	Director, Unit 2
R. Ewing	Supervisor, Design Engineering, Unit 2
K. Fox	Supervisor, Engineering, Unit 2
R. Joshi	Manager, Regulatory Compliance, Unit 2
G. Komoski	ICAVP Inspection Lead, Design Engineering
B. Wilkens	Manager, Programs and Engineering Standards
R. Lawrence	Representative, ICAVP
R. Bonner	Engineering Supervisor, Unit 2 Operations
J. Pizzi	Representative, ICAVP
R. Crittenden	Representative, ICAVP
M. Bain	Manager, Technical Support Engineering
M. Flasch	Manager, Recovery Oversight
P. DiBeneregio	Director A &P, Nuclear Oversight
M. Healy	Lead, Nuclear Oversight
Connecticut Nuclear Energy Advisory Council	
T. Concannon	Representative
US Nuclear Regulatory Commission	
E. Imbro	NRC/Deputy Director, ICAVP, SPO
P. Koltay	NRC/Chief, ICAVP, SPO
R. McIntyre	NRC/ICAVP, SPO - Team Leader
B. Hughes	NRC/ICAVP, SPO - Team Member
P. Narbut	NRC/ICAVP, SPO - Team Member
R. Quirk	NRC Contractor - Team Member
D. Beaulieu	NRC Senior Resident Inspector - Unit 2
S. Jones	Resident Inspector - Unit 2

Appendix C

List of Critical Design Characteristics (CDCs)

No.	Calculation	Parameter-Critical Design Characteristic	Discipline
01	MSLB-CT	Core power level =2771.1 MWT for 102 percent assuming 17.1 MWT from pump heat	I&C
02	MSLB-CT	Max. Pressurizer Pressure = 2300 psia	Operations
03	MSLB-CT	Max RCS Cold Leg temperature = 551.25 @ 102 percent pwr	Operations
04	MSLB-CT	Max RCS Cold Leg temperature = 534.25 @ 0 percent pwr	Operations
05	MSLB-CT	Maximum Initial RCS Flow = 422,466	Mechanical
06	MSLB-CT	Steam Generator mass @ 0 percent power steam = 16,606.7 lbm liquid = 438,181.8 lbm	Operations
07	MSLB-CT	SG Mass @ 102 percent power steam = 23,516..4 lbm liquid = 267,330.2 lbm	Operations
08	MSLB-CT	Bypass of Feedwater Regulating Valve closes @ > 25 percent pwr	Operations
09	MSLB-CT	MAX AFW 100°F	Operations
10	MSLB-CT	Time until AFW reaches SG ≥ 180 seconds	Operations
11	MSLB-CT	CS water temperature 100° F maximum	Operations
12	MSLB-CT	RWST Min. Volume for Spray = 26000 gals	Operations
13	MSLB-CT	Max. Ultimate Heat Sink Temp.= 77°F	Mechanical
14	MSLB-CT	Initial containment temp 120°F (MAX)	Operations
15	MSLB-CT	Initial containment pressure 14.27 psia (min)	Operations
16	MSLB-CT	Containment Free Volume: 1.899E+6 ft^3 (minimum)	Mechanical
17	MSLB-CT	Isolate AFW to affected SG in 600 seconds	Operations
18	MSLB-CT	Containment pressure setpoint for reactor trip = 20.53 psia (max) (5.83 psig)	I&C
19	MSLB-CT	Containment High Pressure Reactor trip delay ≤0.9 seconds max	I&C
20	MSLB-CT	Low SG pressure reactor trip setpoint 384.7 psia (min)	I&C
21	MSLB-CT	Reactor trip delay after low SG pressure trip setpoint <= 0.9 seconds	I&C

No.	Calculation	Parameter-Critical Design Characteristic	Discipline
22	MSLB-CT, MSLB-RCS, SBLOCA,	Insert Rods within 2.75 seconds	I&C
23	MSLB-CT, MSLB-RCS, SBLOCA,	CEA Control Rods release time = 0.5 seconds	I&C
24	SBLOCA, MSLB-CT, MSLB-RCS	CEA insertion time from 180 steps to 18 steps = 2.25 seconds	I&C
25	MSLB-CT	ESAS actuation with MSIAS initiates with containment pressure high signal ≤ 5.83 psig (4.8 psig + 1.03 psi uncertainty)	I&C
26	MSLB-CT	FW pumps trip < 1.15 seconds after high containment pressure signal	I&C
27	MSLB-CT	FW isolation within 14 seconds after containment high signal	I&C
28	MSLB-CT	MSSV Limit Pressure. The 8 SG Safety Valves are modeled as one valve that starts to open @ 1030 psia (was 1000 psia) and reaches full open at 1081.5 psia	Mechanical
29	MSLB-CT	ESAS containment spray initiation on containment high-high pressure signal <= 11.08 psig	I&C
30	MSLB-CT	Containment Spray pump actuation time, assuming VA-20 failure is 16 seconds	I&C
31	MSLB-CT	Cont. Spray pump actuation time for fast transfer failure - 35.6 seconds	I&C
32	MSLB-CT	Containment Heat Removal - Containment Spray: Header Fill Time, Train A - 33 seconds Header Fill Time, Train B - 26 seconds	Mechanical
33	MSLB-CT	Containment Heat Removal - Containment Spray: Minimum CS Flow Rate is 1300 gpm/Pump (one pump operating) 0 percent-50 percent Power Cases	Mechanical
34	MSLB-CT	Containment Heat Removal - Containment Spray: Minimum CS Flow Rate is 2600 gpm total (1300 gpm/pump) -102 percent Power Case	Mechanical
35	MSLB-CT	Initiate CAR System - Peak Pressure Case: 2 CAR Coolers (min.) operating - slow speed	Mechanical
36	MSLB-CT	Initiate CAR System - Peak Pressure Case Max. Air Side Fouling = 0.000	Mechanical

No.	Calculation	Parameter-Critical Design Characteristic	Discipline
37	MSLB-CT	Initiate CAR System - Peak Pressure Case: CAR Air Flow = 34,800 cfm/fan (2 fans operating)	Mechanical
38	MSLB-CT	Initiate CAR System - Peak Pressure Case: CAR Heat Removal Capacity - 99.35 MBTU/hr	Mechanical
39	MSLB-CT	Initiate CAR System - Peak Temperature Case: 4 CAR coolers (min.) operating - slow speed	Mechanical
40	MSLB-CT	Initiate CAR System - Peak Temperature Case: Max. Air Side Fouling 0.000	Mechanical
41	MSLB-CT	Initiate CAR System - Peak Temperature Case: CAR Heat Removal Capacity - 99.35 MBTU/hr	Mechanical
42	MSLB-CT	SIAS on CHPS setpoints ≤ 5.83 psig	I&C
43	MSLB-CT	Max time from CHS to time CAR cooling unit fan is at rated speed with VA-20 failure - 15 seconds	I&C
44	MSLB-CT	Max time from CHS to time CAR cooling unit fan is at rated speed with fast transfer failure - 26 seconds	I&C
45	MSLB-CT	Setpoint ≤ 5.83 psig SIAS signal for RBCCW & SW	I&C
46	MSLB-CT	Component Cooling - RBCCW - Peak Pressure Case: Pre-SRAS Flow to Miscellaneous Users = 1200 gpm	Mechanical
47	MSLB-CT	Component Cooling - RBCCW - Peak Pressure Case RBCCW Heat Exchanger Overall Heat Transfer Area	Mechanical
48	MSLB-CT	Component Cooling - RBCCW - Peak Pressure Case Max. Shell Side Fouling = 0.0005	Mechanical
49	MSLB-CT	Component Cooling - SW - Peak Pressure Case: Max. Tube Side Fouling = 0.0005	Mechanical
50	MSLB-CT	Component Cooling - RBCCW - Peak Pressure Case: RBCCW Flow per CAR (Pre-SRAS)=2000 gpm	Mechanical
51	MSLB-CT	Component Cooling - SW - Peak Pressure Case: Min. RBCCW Tube Side Flow = 7570 gpm	Mechanical
52	MSLB-RCS	RCS Flow = 360,000 gpm (nominal) (37,640 lbm/sec @ 549°F)	Mechanical
53	MSLB-RCS	RWST boron concentration = 1720 ppm (min)	Operations
54	MSLB-RCS	AFW Full Flow (2 Pumps) to Affected SG = 1320 gpm (maximum) = 2 x (600 gpm + 10 percent uncertainty)	Operations
55	MSLB-RCS	Low flow trip setpoint in 1.35 seconds - 85 percent of initial coolant flow	I&C

No.	Calculation	Parameter-Critical Design Characteristic	Discipline
56	MSLB-RCS	CEA breakers open in 2 seconds for low coolant flow + 0.65 seconds	I&C
57	MSLB-RCS	Rod insertion begins 2.5 seconds after break	I&C
58	MSLB-RCS	SIAS on low Pressurizer pressure at 1576 psia	I&C
59	MSLB-RCS	RCS low flow trip setpoint = 85 percent of initial flow	I&C
60	MSLB-RCS	Trip delay =0.65 seconds	I&C
61	MSLB-RCS	Reactor trip on SG pressure = 656 psia	I&C
62	MSLB-RCS	SG Low pressure trip delay = 0.9 seconds	I&C
63	MSLB-RCS	SIAS initiates on low Pressurizer pressure of 1576 psia for boron injection	I&C
64	MSLB-RCS	HPSI delay is less than 25 seconds for boron injection	I&C
65	MSLB-RCS	CVCS - Emergency Borate	Operations
66	MSLB-RCS	MSIAS initiation on low SG pressure ≥476 psia	I&C
67	MSLB-RCS	MSIVs closed within 6.9 seconds	I&C
68	MSLB-RCS	FRV and FWIV close within 14 seconds of MSIAS initiation	I&C
69	MSLB-RCS	Isolate Main Steam Line	Operations
70	MSLB-RCS	ESAS Actuation on 1576 psia to add inventory	I&C
71	MSLB-RCS	ESAS Actuates HPSI within 25 seconds for inventory	I&C
72	MSLB-RCS	RCS-P/I HPSI Flow Initiate (1 pump available)	Mechanical
73	MSLB-RCS	RCS-PTS	Operations
74	SBLOCA	RCS Pump Performance	Mechanical
75	SBLOCA	Max SG tube plugging - 500 tubes	Mechanical
76	SBLOCA	Max Safety Injection Tank temperature = 106.8°F	Operations
77	SBLOCA	Charging System Injection Temperature = 140°F	Mechanical
78	SBLOCA	FW isolation valves close in 30 seconds (minimum) after a scram	I&C
79	SBLOCA	Reactor Trip TM/LP on minimum floor pressure of 1700 psia	I&C
80	SBLOCA	TM/LP Trip delay = 0	I&C
81	SBLOCA	Minimum SBLOCA ESAS actuation setpoint > 1500 psia	I&C
82	SBLOCA	ESAS Actuation - SIAS Initiate: HPSI Flow Delay = 45 seconds (maximum)	Mechanical

No.	Calculation	Parameter-Critical Design Characteristic	Discipline
83	SBLOCA	Charging system response time = 35 seconds max.	Operations
84	SBLOCA	Core Cooling - HPSI Flow - Flow per tables established for 5 percent pump degradation (was 5 percent and 7 percent degradation)	Mechanical
85	SBLOCA	Core Cooling - Charging: Charging Pump Flow = 42 gpm (was 39.6 gpm)	Mechanical
86	SBLOCA	All RCPs manually tripped <300 Seconds	I&C
87	SBLOCA	MSSV Limit Pressure: MSSVs open @ Tech. Spec. Setpoint + 3 percent Tolerance	Mechanical
88	SBLOCA	MSSV Limit Pressure Capacity = 220.6 lbm/sec/valve. Minimum Blowdown = 6 percent	Mechanical
89	SBLOCA	ESAS initiation on 0 percent SG narrow range level	I&C
90	SBLOCA	MDAFW pump initiation within 240 seconds of reaching 0 percent NR level	I&C
91	SBLOCA	TDAFW pump initiated manually within 600 seconds	I&C
92	SBLOCA	AFW Flow Rate: Minimum Flow - 5 percent and 7 percent Pump Degradation Curves	Mechanical

Appendix D
List of Acronyms

AFW	auxiliary feedwater
ANSI	American National Standards Institute
AR	action request
ASME	American Society of Mechanical Engineers
CDC	critical design characteristic
CEA	control element assembly
CEDM	control element drive mechanism
CFR	*Code of Federal Regulations*
CMP	configuration management plan
CR	condition report
CST	condensate storage tank
ECCS	emergency core cooling system
EDG	emergency diesel generator
EMC	electromagnetic compatibility
EMI	electromagnetic interference
EOP	emergency operation procedure
ESF	engineered safety feature
ESFAS	engineered safety feature actuation system
EWR	engineering work request
FSAR	Final Safety Analysis Report
FSARCR	Final Safety Analysis Report Change Request
FW	feedwater
HELB	high-energy line break
HPSI	high pressure service injection
I&C	instrumentation and control
ICAVP	Independent Corrective Action Verification Program
IFI	inspection followup item
IST	inservice testing requirement
LCO	limiting condition of operation
LER	Licensee Event Report
LOCA	loss-of-coolant accident
MCC	motor control center
MSLB	main steam line break
MSLBCT	main steam line break containment analysis
MSLBRCS	main steam line break reactor coolant system analysis
M&TE	measuring and test equipment

NCR	nonconformance reports
NCV	non-cited violation
NGP	Nuclear Group Procedure
NNECO	Northeast Nuclear Energy Company
NRC	U.S. Nuclear Regulatory Commission
PAM	post-accident monitoring
P&ID	piping and instrumentation diagrams
PDCR	Plant Design Change Request
PORC	Plant Operations Review Committee
PTSCR	Plant Technical Specification Change Request
RG	Regulatory Guide
RPS	reactor protection system
RWST	refueling water storage tank
SAR	safety analysis report
SBLOCA	small break loss of coolant accident
SE	safety evaluation
SER	safety evaluation report
SORC	Station Operations Review Committee
SP	surveillance procedure
SWS	service water system
TM/LP	thermal margin/low pressure
TRM	Technical Requirements Manual
TS	Technical Specification
UIR	unresolved item report
USQ	unresolved safety question
VIO	violation
VTM	vendor technical manual